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August 24, 2026

Lisa Felice
Executive Secretary
Michigan Public Service Commission
7109 West Saginaw Highway
Lansing, MI 48917

RE: 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
MPSC Case No. U-22046

Dear Ms. Felice:

Attached for electronic filing in the above captioned matter is DTE Electric Company's Revised Direct Testimony and Exhibits of Witnesses Steven B. Ambrose, Jennifer E. Nelson, Quinn Gerdes, Allen J. Kryscynski, Joseph E. Robinson, and Jason D. De Stigter. Corrections to testimony and exhibits are outlined briefly in the attachment to this letter and redlined versions of testimony and exhibits will be provided to the parties for reference. Also attached is a Proof of Service.

Please feel free to contact me with questions, comments, or concerns.

Very truly yours,

Jon P. Christinidis Digitally signed by Jon P. Christinidis
Date: 2026.08.24 19:41:12 -04'00'

Jon P. Christinidis

JCP/erb
Attachments

cc: Service List

U-22046 Principal Corrections

Witness	Revisions
Ambrose	Updated testimony to add the word "Revised" following references to Exhibit A-24 Sch N3. Revisions to A-24 Sch N3 correct an inadvertent cost categorization error by reallocating amounts to the appropriate categories. These changes were provided in discovery and do not affect total IT cost.
Nelson	JEN-3 line 17; JEN-52 lines 14, 18, 20; Exhibit A-14 Sch D5.7 row 58 "Public Service Electric & Gas Co." removed, row 78 "% of Proxy Group" updated columns "Volumetric Risk Mitigation", "Jurisdiction Test Year", "Jurisdiction Rate Base Methodology".
Gerdes	QG-3 line 24; Exhibit A-39 Sch AD8 p.3 line 24 column (c), line 26 column (c).
Kryscynski	Exhibit A-13 Schedule C5.6 was corrected to address the calendar year timing for corrective maintenance and a reduction in Preventative Maintenance expense. See pages AJK-5 line 8; AJK-7 lines 9, 11, 12, 17; AJK-13 lines 4, 10; AJK-17 line 8; AJK-45 line 13 for corresponding testimony corrections.
Robinson	Updated testimony to add the word "Revised" where appropriate. See pages JER-14 to JER-17 for corrections to hardening and arc wire miles; Exhibit A-12 Sch B5.4 p.1 column (f) rows 20, 24, 25; p.9 column (f) rows 28, 33, 42, 43; p.16 column (c) rows 6, 12, 13; p.17 column (f) row 35; p.18 column (f) row 38; p.22 column (f) row 188. Updated testimony to add the word "Revised" following references to Exhibit A-13 Schedule C5.6 which Witness Robinson co-sponsors.
De Stigter	Updated testimony to add the word "Revised" following references to Exhibit A-28 Sch R3. Within Exhibit A-28 Sch R3, corrections were made to Figures 4-11, 4-12, 4-14, 4-15, 4-16, 4-17, 4-19, 4-20, 4-21, 4-22, 5-1, 5-4, and corrections were made to certain percent and dollar figures on pages 106, 107, and 108.

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-22046

QUALIFICATIONS

AND

REVISED DIRECT TESTIMONY

OF

STEVEN B. AMBROSE

DTE ELECTRIC COMPANY
QUALIFICATIONS AND REVISED DIRECT TESTIMONY OF STEVEN B AMBROSE

Line No.

1 **I Background and Qualifications**

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

3 A1. My name is Steven B. Ambrose. My business address is One Energy Plaza, Detroit,
4 Michigan, 48226. I am a Vice-President and the Chief Information Officer for DTE
5 Energy (DTE).

6

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

8 A2. I am testifying on behalf of DTE Electric Company (DTE Electric or Company).

9

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

11 A3. In 1991, I earned a Bachelor's degree in Business Administration from Bellevue
12 College. In 2008, I earned a Master's degree in Business Administration with high
13 distinction from the University of Michigan.

14

15 **Q4. What work experience do you have?**

16 A4. I joined DTE Energy in 1998 and since that time have served in a variety of
17 progressively more responsible information technology (IT) roles including the
18 oversight of the Company's enterprise business systems, the IT operations of DTE
19 Energy's non-utility affiliates, and the stewardship of the Company's IT strategy
20 and enterprise architecture. In 2003, I was appointed Director of IT Process and
21 Skills where I oversaw all of DTE's application development staff and
22 methodologies and oversaw IT governance functions including its Project
23 Management Office ("PMO"), quality management, asset utilization, workforce
24 planning, and process management and metrics.

1 I was appointed in 2009 to Director of Enterprise Performance Management
2 ("EPM") and Chief of Staff to the CEO, in which I was responsible for the oversight
3 of corporate performance and coordinated various corporate-wide initiatives,
4 including the development and roll-out of corporate priorities, vision, and mission
5 materials, initiating committees to oversee each of the corporate priorities, and the
6 company's adoption of continuous improvement methodologies like Six Sigma and
7 Hoshin Kanri, a management tool for continuous improvement. I was appointed to
8 my current position in 2011.
9
10 **Q5. What are your current duties and responsibilities?**
11 A5. As a Vice-President and the Chief Information Officer for DTE Energy, I am
12 responsible for securing, operating, and applying the Company's information
13 technology investments and assets toward achieving DTE's strategic objectives.
14 These objectives include, among other things, service and operational excellence,
15 exceptional customer satisfaction, storm response excellence, and outstanding
16 productivity.
17
18 **Q6. Do you hold any certifications or are you a member of any professional**
19 **organizations?**
20 A6. I have maintained my active Project Management Professional ("PMP")
21 certification since 2001.
22
23 **Q7. Have you previously sponsored testimony before the Michigan Public Service**
24 **Commission (MPSC or Commission)?**
25 A7. Yes. I have sponsored the IT testimony in the following case:

1 U-21860 2025 Electric Rate Case

2

3 **II Purpose of Testimony and Summary**

4 **Q8. What is the purpose of your direct testimony?**

5 A8. The purpose of my direct testimony is to:

6 1. Introduce DTE Electric's key drivers and strategy for Information Technology
7 investments to support maintaining the security, reliability and resiliency, and
8 cost effectiveness of IT assets.
9 2. Describe the IT capital investment framework and planning process that drives
10 the IT Organization's project prioritization and cost estimation processes;
11 3. Support the reasonableness of DTE Electric's IT capital expenditures in the
12 amount of $155.0 million for the historical test year ended December 31, 2025,
13 $198.4 million in the bridge period (for the 14 months ending February 28,
14 2027), and $173.8 million for the projected test period ending February 29,
15 2028; and
16 4. Discuss the variance between projected differences in 2025 and 2026 as
17 compared to final order for Case No. U-21860 dated February 19, 2026 for
18 projects that meet the requirement established in the MPSC's Order dated May
19 2, 2019 in Case No. U-20162.

20

21 **Q9. How would you summarize your testimony?**

22 A9. Information Technology (IT) represents the systems, platforms, and applications
23 that occupy an increasingly ubiquitous and critical position in modern utility
24 operations. IT focuses on managing information and making it electronically
25 accessible to users through information processing, networking, and cloud systems

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(while Operational Technology (OT) focuses on enabling communication to keep assets and systems operational). IT is continuously advancing and offering innovative and useful capabilities that DTE Electric can apply to the benefit of its customers. To successfully capture those capabilities, the Company must also continuously analyze and plan for how to maintain and modernize its systems in a manner that is cost-effective and delivers the promise of IT advancements for customers and the community. The IT investments presented in my direct testimony represent the Company's plan for this work, which has been developed with the purpose of continuing to provide secure and reliable service to customers for years to come.

Q10. How is your testimony organized?

A10. My testimony consists of the following sections:

Section I Background and Qualifications

Section II Purpose of Testimony and Summary

Section III IT Key Drivers and Investment Framework

Section IV Investment Framework, Selection, and Approval

Section V Cost Recovery Request and MPSC Requirements

Section VI IT Capital Investment Details

A. Shared IT Portfolio

1. Information Technology for IT Sub-Portfolio

2. Information Protection Security Sub-Portfolio

3. Infrastructure Operations Sub-Portfolio

4. Enterprise Data and Digital Platform Sub-Portfolio

Line No.

B. Corporate Applications Portfolio

C. Plant & Field Portfolio

D. Customer IT Portfolio

E. Projects Under $250,000

Section VII Historical Spend Variance

Q11. Are you sponsoring any exhibits in this proceeding?

A11. Yes. I am sponsoring the following exhibits:

Exhibit	Schedule	Description
A-12	B5.7	Projected Capital Expenditures - Information Technology
A-12	B5.7.1	Corporate Applications
A-12	B5.7.2	Customer IT
A-12	B5.7.3	Not used in this rate case
A-12	B5.7.4	Plant & Field
A-12	B5.7.5	Information Technology for IT (IT for IT)
A-12	B5.7.6	Information Protection Security (IPS)
A-12	B5.7.7	Infrastructure Operations
A-12	B5.7.8	Enterprise Data and Digital Platform
A-24	N1	IT Business Cases – Executive Summaries
A-24	N2	Historical Spend Variance Summary
A-24	N3 Revised	IT Capital Investments with Additional Project Details
A-13	C5.13	Projected Operation and Maintenance Expenses – Information Technology

Line No.

Q12. Were these exhibits prepared by you or under your direction?

A12. Yes, they were.

III IT Key Drivers and Investment Framework

Q13. Does the DTE IT Organization solely serve DTE Electric?

A13. The IT Organization serves DTE Electric, DTE Gas, and the DTE Energy enterprise as a whole. It works with the DTE Electric business units to prioritize IT investment needs and develop IT solutions. Specifically, for DTE Electric, the IT Organization seeks to enable the Company to carry out its mission of providing safe, reliable, low-cost energy to customers. This objective is accomplished through the development of IT investment plans based on robust, data-based budgeting and planning, a rigorous project prioritization and cost estimation process, and appropriate metrics and measures that guide project implementation and cost management.

Q14. What are DTE Electric's key investment drivers for IT?

A14. The Company's key IT investment drivers are (1) cybersecurity for grid reliability and customer protection, (2) reliability and resiliency of IT assets, and (3) cost effectiveness of IT investments (affordability). Each of these drivers is reflected through the prudent investments for which DTE Electric is seeking recovery in this case as detailed in Section VI below and in the Company's project selection and effective cost management processes and practices.

Q15. What is the cybersecurity investment driver?

Line No.

1 A15. DTE Electric remains focused on improving the security of its assets, systems, and
2 customer data from cyber threats. Cyberattacks on utilities can cause widespread
3 blackouts, economic disruptions, and even weaken national defense, as energy
4 companies operate within one of sixteen critical infrastructure sectors identified by
5 the federal government "whose assets, systems, and networks, whether physical or
6 virtual, are considered so vital to the United States that their incapacitation or
7 destruction would have a debilitating effect on security, national economic security,
8 national public health or safety, or any combination thereof."[1] As cyber threats
9 continue to become more sophisticated over time, the Company must likewise
10 continue to (1) mature its security protections to be prepared for ever-evolving
11 threats, and (2) meticulously operate those protections to be ready to respond to
12 threats as they arise. DTE Electric's cybersecurity investments align with the
13 Company's security controls supported by National Institute of Standards and
14 Technology (NIST) security standards and North American Electric Reliability
15 Corporation Critical Infrastructure Protection (NERC CIP) reliability standards.
16
17 **Q16. What is the reliability and resiliency investment driver?**
18 A16. The Company's IT systems must operate continuously without interruption,
19 particularly at those times when the grid is stressed and customers most need the
20 IT systems to function. During the most significant storms and the hottest summer
21 days, customers need the DTE Electric customer channels (*e.g.*, mobile app,
22 website, etc.) to reliably provide the most current information and Company crews
23 need IT systems to function reliably to restore power. This investment driver results

[1] Presidential Policy Directive (PPD) 21 (issued Feb. 12, 2013), available at https://www.cisa.gov/sites/default/files/2023-01/ppd-21-critical-infrastructure-and-resilience-508_0.pdf (identifying the energy sector as "uniquely critical due to the enabling functions [it] provide[s] across all critical infrastructure sectors").

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in (1) initial investments in IT systems and solutions and (2) constant maintenance of those systems and solutions to ensure reliability and resiliency. Ongoing investment in systems, hardware, software, and component maintenance must occur to keep IT assets healthy and ensure their reliability and resiliency for customers.

Q17. What is the Cost Effectiveness of IT Investments (Affordability) investment driver?

A17. DTE Electric strives to invest in ways that optimize the cost effectiveness of IT investments for the benefit of customers in two primary ways. First, the Company employs a number of strategies to ensure investments are made at the most economical price point. These strategies include, for example, competitive bidding, consideration of alternatives, and maximization of investment value by considering economies of scale and cost-effective maintenance. Second, the Company achieves economic feasibility by using IT assets to improve internal processes and asset efficiencies to prevent outages, repairs, and replacements.

Q18. How do DTE Electric's key IT investment drivers translate into IT investments?

A18. The Company's IT investments, as driven by these key drivers, can be viewed through the lenses of Portfolios and Investment Categories.

The four IT investment Portfolios generally align with DTE Electric's business units and thus indicate the part of the Company for which the investment will bring value:

Line No.

1 (1) Shared IT, and its Sub-Portfolios:

2 (a) Information Technology for IT (IT for IT),

3 (b) Information Protection Security (IPS),

4 (c) Infrastructure Operations,

5 (d) Enterprise Data Analytics and Digital Transformation,

6 (2) Corporate Applications;

7 (3) Plant & Field; and

8 (4) Customer IT

9

10 Within each IT investment Portfolio and Sub-Portfolio, the Company organizes and
11 plans its IT investments using five Categories. Each Category corresponds to an IT
12 investment purpose – the nature of the value brought to the Portfolio by that
13 investment. In certain cases, an investment may apply to multiple Categories, in
14 which case DTE Electric categorizes the project according to the investment
15 category that represents the project's most prominent purpose and features:

16 (1) Regulatory/Compliance;

17 (2) Sustainment;

18 (3) Return-to-Health;

19 (4) IT Enhancements; and

20 (5) Strategic.

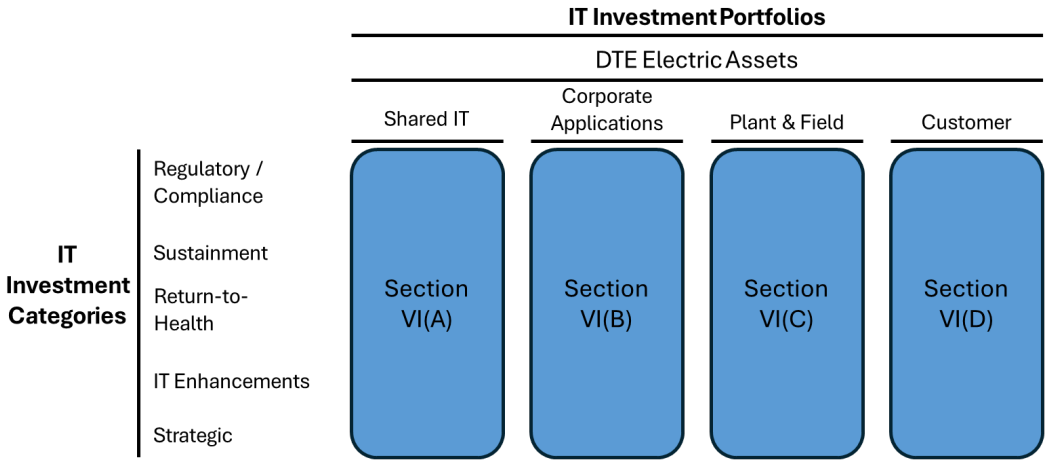
21

22 The interplay between the Portfolios and Categories is illustrated by Figure 1. As I
23 note above, a particular investment may have components or aspects that fall into
24 more than one category. For purposes of my testimony, investments are organized

Line No.

1 according to the primary category to which they relate. In the remainder of this
2 section, I describe each of the Portfolios and Categories of IT investments.

3 Figure 1 IT Investment Portfolios and Categories



4

5 IT Portfolios

6 **Q19. What is included in the Shared IT Portfolio?**

7 A19. The Shared IT Portfolio supports the DTE Energy enterprise by establishing the IT
8 foundation required by the other Portfolios. The investments within the Shared IT
9 Portfolio are presented in Section VI.A of my testimony. The Shared IT Portfolio
10 encompasses four Sub-Portfolios:

11

12 1. Information Technology for IT (IT for IT) – The IT for IT Sub-Portfolio
13 consists of capital investments made for the enterprise as a whole or that enable the
14 functioning of the IT Organization in support of the Company. These investments
15 represent initiatives that either are more periodic in nature than ongoing year-over-

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1 year asset replacements or bring significant new capabilities to the IT department.
2 See Section VI.A.1.
3
4 2. Information Protection Security (IPS) – IPS Sub-Portfolio investments
5 focus on the reliability of cybersecurity infrastructure and improving the
6 Company's overall cybersecurity posture in IT and Operational Technology (OT).
7 The Company seeks to improve the combined risk posture across IT and OT by
8 implementing a unified approach to security governance, covering both areas while
9 recognizing that cybersecurity requirements and risk appetite may differ across the
10 two domains. DTE's cybersecurity investments use a balanced approach to keep
11 cybersecurity infrastructure healthy and appropriately updated to address emerging
12 threats, while the Company increases its focus on maturing cybersecurity controls
13 in the OT domain. See Section VI.A.2.
14
15 3. Infrastructure Operations – The Infrastructure Operations Sub-Portfolio is
16 responsible for the design, implementation, and secure operation of the Company's
17 overall IT Infrastructure. This includes all the Company's physical IT assets (i.e.,
18 datacenters, servers, computers, network devices, and the licensed software that
19 supports those assets). This Sub-Portfolio is responsible for the day-to-day
20 operation of these assets, the overall health of the assets (including operational
21 growth, capacity, and availability standards), and from a project perspective, the
22 enhancement of these assets to meet project requirements. See Section VI.A.3.
23
24 4. Enterprise Data & Digital Platform – The Enterprise Data and Digital Sub-
25 Portfolio is responsible for building and maintaining the Company's cloud-based

and on-premises data and digital platforms. This includes data storage and processing infrastructure, software for data management and usage, and foundational capabilities to enable analytics, critical business applications, and day-to-day operations. This Sub-Portfolio supports DTE's data and business operations users by providing infrastructure, building applications and integrations to source systems, organizing and documenting available data, and ensuring the reliable delivery of timely, secure, high-quality data and digital solutions to business partners throughout the Company. See Section VI.A.4.

Q20. What is included in the Corporate Applications Portfolio?

A20. The Corporate Applications Portfolio encompasses investments in IT assets and applications used by the enterprise to execute critical internal business functions. This Portfolio supports enterprise business units including Human Resources, Finance and Controller, Legal, Supply Chain, and Fleet & Facilities. The investments within Corporate Applications span the investment Categories discussed further below, and the specific projects are detailed in Section VI.B of my testimony.

Q21. What is included in the Plant & Field Portfolio?

A21. The Plant & Field Portfolio supports IT business systems used by the Company to operate and maintain its plants (e.g., Energy Supply (ENS), Generation Optimization (GenOpts), and the Company's nuclear generating facility, Fermi2) and its field force (e.g., Distribution Operations (DO)). The business systems supported by this Portfolio include core technologies, such as the Work and Asset Management system, which tracks plant maintenance work and is used across all

Line No.

organizations. The Portfolio also supports department-focused systems, including Outage Management, equipment tagging, Mapping, and similar technologies. The investments in the Plant & Field Portfolio cover various categories, which are discussed below. Specific projects are detailed in Section VI.C of my testimony.

Q22. What is included in the Customer IT Portfolio?

A22. The Customer IT Portfolio comprises key systems integrating with the Company's SAP Customer Relationship and Billing (CR&B) platform or other significant Customer systems like those that support the Error Free Communication Initiative. Investments in the Customer Service Portfolio directly impact the Company's interactions with customers. The investments within the Customer IT Portfolio span the investment Categories discussed further below, and the specific projects are detailed in Section VI.D of my direct testimony.

IT Investment Categories

Q23. How does the Company determine the category for each proposed IT investment?

A23. The Company has established specific criteria for each category that I detail below. As explained in Section IV of my testimony below, the Company has continued to review and refine the criteria for each category to ensure the projects are accurately categorized. These refinements facilitate the project selection and prioritization process outlined in Section IV and further advance the Company's key investment drivers to the benefit of customers.

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As part of their categorization, projects are classified as either discretionary or non-discretionary. Non-discretionary investments which fall within the Regulatory/Compliance, Sustainment, and Return-to-Health Categories represent projects that are required by either regulatory directive, compliance standards, or operational necessities essential to maintain a functioning utility system. These represent as "must-do" investments and foregoing them would prevent the Company from safe and reliable service. Discretionary projects, by contrast fall outside the non-discretionary criteria yet remain critical to ensure cybersecurity, support power system reliability and resiliency, or contribute to operational efficiencies.

Q24. What is included in the Regulatory/Compliance category of IT investment?

A24. Investments in the Regulatory/Compliance category represent nondiscretionary spending required to meet and maintain compliance with current or anticipated regulatory and compliance standards over the next two years. In addition to the MPSC, other regulatory agencies that can trigger Regulatory/Compliance projects include, but are not limited to, the North American Electric Reliability Corp (NERC), the Federal Energy Regulatory Commission (FERC), the Nuclear Regulatory Commission (NRC), and the Transportation Security Administration's (TSA) Oil and Natural Gas Pipeline Security standards. These Investments generally include system patching, security configuration of assets, and management of evidence, audit data, and log files in support of ensuring customer and employee security and the reliability and resiliency of IT assets.

Q25. What is included in the Sustainment category?

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A25. The Sustainment category represents non-discretionary spend required to maintain existing applications critical to the Company's day-to-day operations. Capital investments in this category include functional periodic releases, infrastructure upgrades (adaptive maintenance), performance tuning, and data storage enhancements to ensure the reliability and resilience of IT assets.

Q26. What is included in the Return-to-Health category?

A26. The Return-to-Health category represents non-discretionary spend to update or replace hardware and software systems nearing end of life (EOL). These systems that are approaching the end of their serviceable lives and, without update or replacement, will cease to function and adversely impact the Company's Operations. An example is replacing end-of-life network devices, such as data-center core switches and routers, with new components to enhance the connection bandwidth between the Company's data centers.

Q27. What is included in the IT Enhancements category?

A27. The IT Enhancements category includes discretionary investments that make incremental improvements to existing systems, enhancing cybersecurity, reliability and resilience, or cost effectiveness of IT Assets. These investments include adding new features, expanding capabilities on existing platforms, consolidating redundant systems, and enhancing infrastructure for improved operational reliability. IT Enhancement investments may also include technology solutions designed to automate existing manual processes, support regulatory/compliance requirements, and drive efficiency in current processes.

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1 **Q28. What is included in the Strategic category?**

2 A28. While the IT Enhancement category generally focuses on incremental
3 improvements to existing systems, investments falling into the Strategic category
4 are generally linked to the introduction of new value-generating assets or the
5 enablement of new capabilities. This category includes cases where existing
6 applications or assets are at risk of near term obsolescence, as well as multi-year
7 programs that deliver new scope or functionality on an annual basis. For example,
8 the Transparency Electric Data project introduced a new platform to bridge
9 communication gaps on electric reliability investments amid severe weather
10 outages, enhancing localized transparency and increasing customer/stakeholder
11 confidence.

12

13 **IV Investment Framework, Selection, and Approval**

14 **Q29. How would you describe DTE's IT investment selection and approval process?**

15 A29. The Company's investment selection and cost estimation processes are sound and
16 comparable to industry best practices and standards. DTE continues to evaluate
17 opportunities to refine its investment prioritization and cost estimation processes in
18 the interest of making the best project selection with ongoing application of
19 established criteria such as those refined for project categorization since Case No.
20 U-21534, as detailed later in this testimony.

21

22 **Q30. What is DTE's approach to IT investment identification and selection?**

23 A30. The Company utilizes a disciplined budgeting and planning process, recognizing
24 that the Company operates on a limited capital budget. In any given year there is
25 more work that has been identified as needed than the IT Organization can execute

Line No.

1 due to capital budget constraints. As such, the Company may need to adjust or re-
2 sequence a scheduled high priority item based on other emerging needs of greater
3 urgency.
4
5 In addition, as DTE considers cybersecurity, reliability and resiliency of its IT
6 investments, it must also continue to effectively optimize the life cycle of those
7 investments. The Company is always seeking to refresh, replace, and maintain IT
8 investments in a manner that supports these drivers. The Company successfully
9 manages IT asset life cycles by considering thresholds for tolerance in business
10 processes, manual work arounds, and customer needs. For example, a field crew
11 member whose laptop is at end of life may receive a replacement before a System
12 Operations Center (SOC) crew member with a similarly aged machine, since the
13 field crew may have less flexibility to borrow another machine or apply a
14 workaround.
15
16 As discussed in Case No. U-21860, the Company implemented refinements to its
17 estimation and qualification processes for IT investments following Case No.
18 U-21534. The framework outlined in that filing now forms the foundation of the
19 Company's project evaluation approach and continues to guide the proactive,
20 comprehensive assessment of IT projects prior to approval and execution.
21
22 **Q31. What process does the Company use to identify and prioritize IT investment**
23 **projects?**
24 A31. The Company develops and refines its investment strategies and plans across the
25 enterprise through its Annual Planning Cycle (APC). The APC process determines

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where specific, targeted investments will be focused based on near-term priorities and current conditions over a rolling three-year time frame. The APC process as applied to the IT Organization is detailed in Figure 2, below. This process is aligned with the enterprise-wide APC process, with refinements as I discuss later in this section.

Figure 2 DTE IT APC Cadence

The IT APC activities occur in phases. The N+2 Planning phase involves review of capital investments two years out from the investment planning year (N). In the N+1 Planning phase, final investments are approved and appropriated for investments one year out from the investment planning year (N).

Q32. Describe the PPS model used to evaluate discretionary project benefits.

A32. The Company developed the Project Prioritization Score (PPS) model as a framework to evaluate, score, and prioritize discretionary projects. The PPS is used as a standardized scoring and ranking methodology to bring consistency to assessment of discretionary projects across multiple IT investment Portfolios. Commencing with the 2025 investment planning cycle, the Company refined the PPS scoring criteria to align with its key investment drivers, as indicated in Table 1.

Line No.

1 Table 1 Project Prioritization Score Criteria

2

	Strategic Fit			Financial Impact		Operational Impact	
Selection Criteria	Strategic Alignment	Customer Experience	Employee Engagement	Affordability	Cost Benefit	Operational Reliability	Fundamental Capability
Weight (total=100%)	10 %	15%	10%	30%	10%	20%	5%

3 **Q33. What occurs in the "Submitted" state for a capital investment within the IT**
4 **APC process?**

5 A33. In the "Submitted" state, for each capital investment, the business unit submits
6 detailed project scope that identifies the opportunity, functionality, or capability
7 sought with the requested investment, along with its value proposition, related key
8 output measures, key objectives, alternative analysis, and cost estimate.

9

10 At this early-stage within the APC process, a Stage 1 estimate is developed. Stage
11 1 estimates focus on feasibility, desirability, and strategic alignment. These broad-
12 scope estimates provide 3–5 year planning cycles and are based on high-level
13 requirements, historical benchmarks, and analogs.

14

15 **Q34. What happens in the "Screening" state for a capital investment within the IT**
16 **APC process?**

17 A34. In the "Screening" state, requested capital investments undergo a comprehensive
18 review of their alignment with the Company's key investment drivers of (1)
19 cybersecurity for grid reliability and customer protection, (2) reliability and
20 resiliency of IT assets, and (3) cost effectiveness of IT assets. All capital
21 investments, non-discretionary and discretionary, also undergo assessments for
22 alignment with Cloud and Capital Accounting Policy, Supply Chain, Architecture,
23 Security, and Compliance. In addition, discretionary projects are evaluated through

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1 the Project Prioritization Score (PPS) assessment. At this state the estimates
2 progress to a level 2 estimate.

3 **Q35. What happens in the "Qualified" state for a capital investment within the IT**
4 **APC process?**
5 A35. In the "Qualified" state of the IT APC process, the Company utilizes PPS scores
6 and execution capacity to prioritize the capital investment. This ensures that
7 investments with the highest return on investments (ROI) and those that align with
8 the key IT drivers constitute the IT investment plan. Beginning in 2025, the
9 Company is requiring that all projects that are Qualified have a level 2 cost estimate.
10 Level 2 cost estimates are used for detailed project control and near-final decision
11 making. The Qualified projects meeting these criteria then constitute the IT
12 investment plan proposed for approval.
13
14 **Q36. What is the next step in the IT APC process?**
15 A36. In the "TIC Approved" state, the IT investment plan is recommended for review
16 and approval by the Company's Technology Investment Committee (TIC), which
17 is comprised of executives from across DTE.
18
19 **Q37. What are the next steps that occur within the IT APC process before the**
20 **project is approved?**
21 A37. Upon review and approval by the TIC, projects are promoted to the "Detailed
22 Estimate" state, in which a stage 3 estimate is developed. Stage 3 estimates are used
23 for final funding approvals and execution planning. Upon completion of the stage
24 3 estimates in the "Detailed Estimates" state, these projects are then promoted to

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the "Approval Workflow" state for stakeholder approval. Lastly, capital dollars appropriation is completed in the "Approved" state to begin execution.

Q38. Can you please explain the details that are provided in Column I of Exhibit A-24, Schedule N3 Revised?

A38. Column I of Exhibit A-24, Schedule N3 Revised provides estimate classifications for each capital project.

Q39. Can you please describe each of the estimate classifications featured in Exhibit A-24, Schedule N3 Revised?

A39. Yes. Each project's estimated cost listed in Exhibit A-24, Schedule N3 Revised is assigned to one of three estimate classification levels.

Level 1 is intended to provide an initial order of magnitude estimate to determine feasibility and whether the project should proceed. Level 2 is intended to support project design, budget development, initial funding requests, and resource allocations. Level 3 estimates are developed to deliver a high-confidence forecast of project cost, with increased accuracy suitable for moving into execution.

Q40. What are the requirements for Level 1 estimate?

A40. Projects with a Level 1 estimate must have an initial scope of work, an estimated timeframe for project completion, and a preliminary indication of cost. Level 1 estimates evaluate the feasibility, desirability, and strategic alignment of a proposed investment. This early-stage, broad-scope estimates support the Company's 3- to 5-year planning horizon and are derived from high-level requirements, historical cost information from a similar project, and analogous project data.

Line No.

1

2 **Q41. Have each of the projects estimates in Exhibit A-24, Schedule N3 Revised been**
3 **designated as Level 1 meet the requirements for Level 1 estimate?**
4 A41. Yes. As of the date of this filing, each of the projects with a Level 1 estimate
5 featured in Exhibit A-24, Schedule N3 Revised have an initial scope of work, an
6 estimated timeframe for project completion, and a preliminary indication of cost.
7 Items 1 through 4 in the Company's Part III Attachment 15 provide additional
8 details on the internal approvals and business cases that the Company is presenting
9 for these projects.
10
11 **Q42. How were the Level 1 estimates developed?**
12 A42. Level 1 estimates are developed as early-stage estimates that incorporate several
13 key considerations. High-level cost models are informed by external research, such
14 as industry benchmarks and utility peer trends, as well as internal historical data
15 and lessons learned from similar projects. The enterprise architecture team
16 evaluates technology fit and complexity using a standardized complexity matrix to
17 confirm alignment with DTE's platform strategy (for example, SaaS, PaaS, or
18 on-premise solutions). This serves as a strategic feasibility checkpoint to assess
19 platform compatibility and roadmap alignment; where a proposed solution is
20 misaligned or technically infeasible, architects work with business stakeholders to
21 refine requirements and reset expectations.
22
23 **Q43. What are the requirements for a Level 2 estimate?**
24 A43. Projects with a level 2 estimate must have a business case, detailed scope of work,
25 work breakdown structure, initial designs, and a project completion timeframe.

Line No.

Level 2 estimates support DTE's project funding and prioritization decisions. These estimates reflect increased granularity and confidence across labor, non-labor, and vendor cost estimates and are reviewed through formal governance channels. Level 2 estimates serve as a critical checkpoint before committing resources and funding at scale. Approved level 2 estimates are incorporated into the company's investment portfolio and underpin formal alignment with strategic priorities.

Q44. Have the projects in Exhibit A-24, Schedule N3 Revised that are designated with a Level 2 satisfied all requirements associated with that classification?

A44. Yes. As of the date of this filing, each of the projects with a level 2 estimate featured in Exhibit A-24, Schedule N3 Revised have a business case, detailed scope of work, work breakdown structure, initial designs, and a project completion timeframe. Items 1 through 4 in the Company's Part III Attachment 15 provide additional details on the internal approvals and business cases that the Company is presenting for these projects.

Q45. How are the Level 2 estimates developed?

A45. For projects with a level 2 estimate, capital costs are estimated using preliminary quotes obtained from vendors and contractors, reflecting the more defined scope and strategic decisions at this stage. All key decisions impacting cost, scope, and execution—including execution strategy (PMO oversight versus distributed leadership, and agile, phased, or hybrid delivery approaches), vendor selection with licensing models and implementation partners, solution configurations, and downstream IT workstream impacts across infrastructure, security, support, and integration—are reviewed for executive approval and finalized. These estimates

Line No.

provide a defined cost range based on the specified solution and comprehensive assessment of technical and resource requirements.

Q46. What are the requirements for a Level 3 estimate?

A46. Projects with a level 3 estimate must have detailed designs, a defined procurement strategy, vendor proposals, and a proposed schedule. Level 3 estimates are used for final funding approvals and execution planning. Level 3 estimates are developed once the solution design is finalized and all requirements are fully documented, providing the most detailed view of project costs based on the scope known at that time.

Q47. Have the projects in Exhibit A-24, Schedule N3 Revised that are designated with a Level 3 satisfied all requirements associated with that classification?

A47. Yes. As of the date of this filing, all projects featured in Exhibit A-24, Schedule N3 Revised with a level 3 estimate have detailed designs, a procurement strategy, vendor proposals, and a proposed schedule. Items 1 through 4 in the Company's Part III Attachment 15 provide additional details on the internal approvals and business cases that the Company is presenting for these projects.

Q48. How were the capital costs estimated Level 3 estimates?

A48. Level 3 estimates are based on fully defined scope and are considered execution ready. At this execution-ready stage, vendor cost estimates are secured and incorporated into detailed cost breakdowns; full resource plans are developed covering internal teams, external partners, and third-party dependencies; and detailed workstream estimates are documented across functional areas including

Line No.

endpoints, infrastructure, application support, cybersecurity, and training. Execution readiness is confirmed through validated project timelines, milestones, and delivery models, while strict governance oversight requires any post-estimate changes to scope, schedule, or cost to receive approval from business unit stakeholders and finance. Contracting and procurement activities are initiated or finalized based on this cost structure, establishing the foundation for performance tracking and financial control throughout delivery. See below Figure 3, which shows the IT cost estimation progression overlayed on the DTE APC cadence:

Figure 3 IT Cost estimation progression

In sum, DTE's cost estimation methodology for IT capital investments is designed to support strategic decision-making, investment planning and disciplined execution. This approach provides clear purpose and criteria for cost estimation by applying progressive elaboration as the project matures. By aligning estimation rigor with decision milestones as part of the annual planning cycle, DTE reinforces transparency, strategic alignment, and disciplined execution of IT investments.

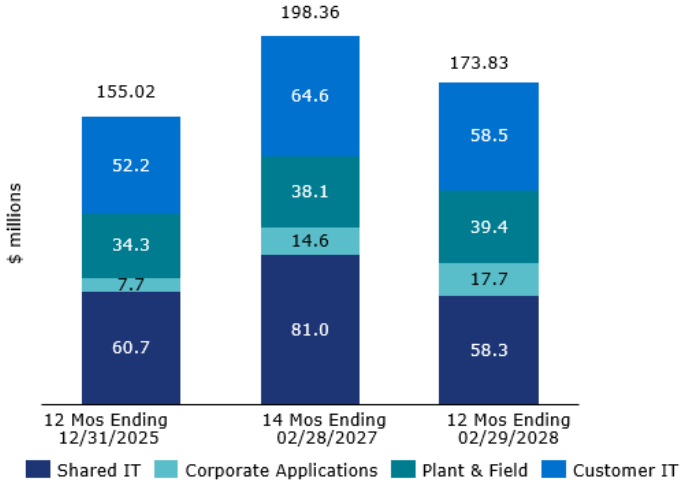
Q49. How does the Company explore and consider alternate solutions for each project in the IT APC process?

Line No.

1 A49. For each new investment represented in my testimony, the Company has considered
2 the following standard alternatives:
3 • Maintain status quo: forego or delay the investment; "do nothing" within
4 the instant rate case period and defer the activity to a future period;
5 • Manual: revert to a manual process rather than updating or replacing the
6 existing system, where applicable or possible; and
7 • Look outside: look outside of the platform for an alternative to implement
8 in place of the existing solution that has an advantage for customers or the business
9 unit.
10 These alternatives are addressed where applicable in Section VI of my testimony
11 and in the executive summaries for the IT investments provided as part of Exhibit
12 A-24, Schedule N1 IT Business Cases – Executive Summaries.
13
14 **V. Cost Recovery Request and MPSC Requirements**
15 **Q50. What level of IT investment capital does your testimony support?**
16 A50. My testimony supports DTE Electric IT capital expenditures in the amount of
17 $155.0 million for the historical test year ended December 31, 2025, $198.4 million
18 in the bridge period (for the 14 months ending February 28, 2027), and $173.8
19 million for the projected test period ending February 29, 2028. These amounts are
20 represented graphically in Figure 4, below.

Line No.

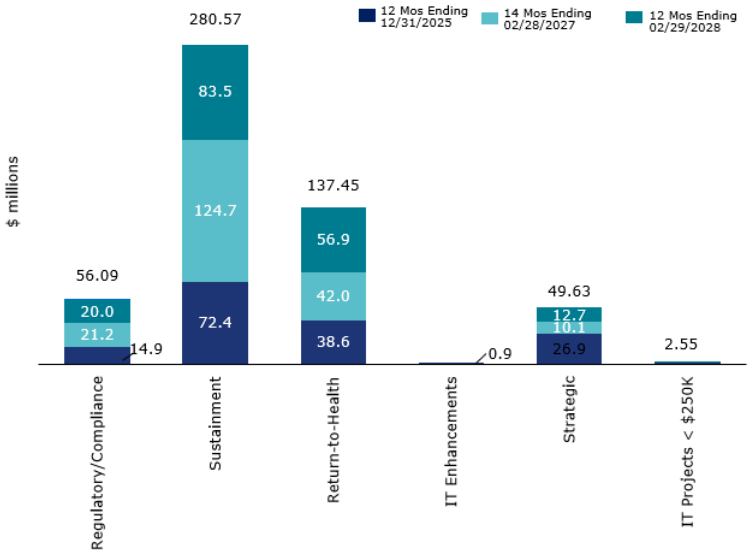
Figure 4 DTE Electric Capital Expenditure by Period



Q51. How are these expenditures spread across the IT investment Categories?

A51. See Figure 5, below, for a depiction of these expenditures by investment category.

Figure 5 DTE Electric IT Capital Expenditure by category



Line No.

1 **Q52. What are the Commission's requirements as specified in previous orders**
2 **regarding the information to be provided in support of IT projects proposed**
3 **for cost recovery?**
4 A52. Historically, in Case No. U-18238, the Commission set forth ten filing requirements
5 directly related to the highest cost Top 25 IT and OT projects in the projected test
6 year. These requirements can be found in the Part III filing. The Part III filing
7 requirements were further enhanced in the Commission's order dated May 18,
8 2023, in the same proceeding, to include additional information in a spreadsheet
9 and readable PDF format. In the Commission's order in Case No. U-20162 dated
10 May 2, 2019, the MPSC instructed the Company to provide a breakdown of both
11 O&M and Capital cost into two or three Sub-Categories and adopted nine additional
12 requirements for projects greater than $0.5 million addressing scope, schedule, cost,
13 and alternatives. In its order for Case No. U-18238 regarding updates to the Rate
14 Case Filing Requirements, issued on July 9, 2024, the Commission provided
15 updated guidance for the detailed filing requirements related to Information
16 Technology. As part of the Part III filing, utilities must now include project-level
17 details covering capital and O&M cost breakdowns, project scope, expected
18 benefits or value, alternatives considered, and project timing. In the Commission's
19 order in Case No. U-21297 dated December 1, 2023, the Commission directed the
20 Company to provide an exhibit outlining IT O&M spend. No new requirements
21 were established in the Commission's final order in Case No. U-21534 dated
22 January 23, 2025 (Case No. U-21534 Final Order) and Case No. U-21860 dated
23 February 19, 2026 (Case No. U-21860 Final Order).
24
25 The exhibits listed below have been developed to meet the aforementioned
26 requirements and will be provided with the testimony:

Line No.

1 • Exhibit A-12 Schedule B5.7 is a summary view of IT capital cost by
2 Portfolio and investment category across the historical year (2025), bridge year (14
3 months ending 02/28/2027), and projected test year (12 months ending 02/29/2028)
4 periods.
5 • Exhibits A-12 Schedules B5.7.1 through B5.7.8 present the capital spend in
6 the historical, bridge, and projected test periods within each Portfolio. I have
7 structured my testimony to address IT projects under the Portfolio they support, in
8 the same order that the Portfolios and projects in these exhibits are presented, for
9 each project more than $250,000.
10 • Exhibit A-24 Schedule N1 presents the executive summaries for each
11 business case associated with each project over $250,000. Exhibit A-24 Schedule
12 N1 tracks to the same order of projects as Exhibit A-12 Schedules B5.7.1 through
13 B5.7.8. I also provide the corresponding business cases for each project in my
14 workpapers.
15 • Exhibit A-24 Schedule N3 Revised provides a greater level of detail
16 consistent with the format set forth in the rate case filing requirements issued on
17 May 18, 2023 in Case No. U-18238. Each of these IT projects are presented by year
18 and then in Portfolio and project order.
19 • All variance commentary provided within my testimony will reconcile to
20 Exhibit A-12 Schedules B5.7 - B5.7.8. Where additional historical recovery is
21 being requested, please refer to Exhibit A-24 Schedule N2.
22 • The IT O&M spend information required in Case No. U-21297 is included
23 as Exhibit U-22046 IT O&M Exhibit A-13 Schedule C5.13. The 'A&G
24 Capitalized' on line 15 reflects the transfer (allocation) of A&G costs to capital as

Line No.

an overhead. The amount of A&G transferred (allocated) is based on the percentage of total direct labor charged to capital.

Q53. What are the capital cost and the corresponding O&M costs for IT Projects?

A53. The capital costs reflected in Exhibit A-24, Schedule N-3 and Exhibit A-12 Schedule B5.7 represent the portion of IT costs, including hardware costs, software costs, and software development costs, allowed to be capitalized in accordance with the Company's accounting policies. These policies define the scope and phases of a project that can be capitalized and the scope and phases of the project that should be expensed. According to these policies the O&M cost is considered cost-to-achieve (CTA). The O&M costs reflected in Exhibit A-24, Schedule N3 Revised represent the total O&M cost-to-achieve for each project and are provided for informational purposes only.

Q54. Can you provide a more detailed description of other IT O&M cost?

A54. Yes. In addition to CTA expense, the Company's IT operating expense, as shown on Exhibit A-13, Schedule C5.13, includes operational labor support (Base Operate) and software maintenance cost (License Management & Maintenance). The IT operational labor support cost represents IT resources that support hardware and software defect remediation (e.g., Office 365 not working as expected, Password Reset Support, multi-factor authentication (MFA) failure and access requests), business support services (e.g., IT Help Desk, Data Center Operation), and IT administration. Commercial software maintenance and support cost represents IT O&M expense, including software maintenance and license for use fees, for on premise and cloud solutions for certain software contracts.

Line No.

Q55. What projected adjustments did you make to O&M as reflected in columns (e) through (h)?

A55. Increases based on the inflation rate (columns e-g) were applied to the adjusted historical test period expenses for the period January 2026 through February 2028, as supported by Witness Uzenski. Line 5, column h reflects an adjustment of $9.8 million for CTA costs driven by volume, in the projected test period, as described in Exhibit A-24, Schedule N3 Revised

Q56. Are there any IT projects that have already been approved for cost recovery in previous rate cases with no additional spend being requested in the instant case?

A56. Yes, the projects listed in Table 2 were approved for cost recovery in Case Nos. U-21534 and U-21860 and are not described further in this testimony.

Table 2 IT Projects Approved in U-21534 and U-21860

Project Name	Portfolio	Category	U-21860 Exhibit Reference	U-21534 Exhibit Reference
Advance Metering Infrastructure (AMI) Field Collection System	Plant & Field	Return-to-Health	Line 22 A-12 B5.7.4	Line 20 A-12 B5.7.4
Advance Metering Infrastructure Application Health	Plant & Field	Sustainment	-	Line 1 A-12 B5.7.4
Agency Web Site AGW Rebuild	Customer Service	Return-to-Health	-	Line 29 A-12 B5.7.2

Line
No.

Project Name	Portfolio	Category	U-21860 Exhibit Reference	U-21534 Exhibit Reference
Application Portfolio Management – APM	Information Technology for IT	Strategic	-	Line 2 A-12 B5.7.5
Azure Active Directory Federation Implementation	Information Protection & Security	Strategic	Line 13 A-12 B5.7.6	Line 10 A-12 B5.7.6
Business Planning and Development (BPD) and Electric Sales & Marketing (ESM) Application Health	Customer Service	Sustainment	Line 11 A-12 B5.7.2	Line 2 A-12 B5.7.2
ClickSoft Application Health	Plant & Field	Sustainment	Line 2 A-12 B5.7.4	Line 3 A-12 B5.7.4
Cloud Security project	Information Protection & Security	Return-to-Health	Line 7 A-12 B5.7.6	Line 5 A-12 B5.7.6
Core ERP Data Archiving	Corporate Applications	Return-to-Health	Line 7 A-12 B5.7.1	Line 10 A-12 B5.7.1
Customer Consent and Preference Management	Customer Service	Regulatory/Compliance	Line 1 A-12 B5.7.2	-
Customer Experience Suite	Customer Service	Return-to-Health	Line 31 A-12 B5.7.2	Line 19 A-12 B5.7.2
Customer Relationship and Billing Program Enhancement	Customer Service	IT Enhancements	Line 41 A-12 B5.7.2	Line 21 A-12 B5.7.3
Customer Service Infrastructure Landscape & Growth	Customer Service	Return-to-Health	Line 32 A-12 B5.7.2	Line 26 A-12 IT Projects <$250K

Line
No.

Project Name	Portfolio	Category	U-21860 Exhibit Reference	U-21534 Exhibit Reference
Cyber Excellence Plan (CEP) Program	Information Protection & Security	Strategic	Line 14 A-12 B5.7.6	Line 11 A-12 B5.7.6
Data Power Replacements	Infrastructure Operations	Strategic	Line 37 A-12 B5.7.7	Line 37 A-12 B5.7.7
Endpoint Protection	Information Protection & Security	IT Enhancements	Line 11 A-12 B5.7.6	Line 8 A-12 B5.7.6
Enterprise Data Analytics – Alteryx and Qlik License Renewal	Enterprise Data & Digital Platform	Strategic (sustainment)	Line 2 A-12 B5.7.8	-
Enterprise Data Platform Application Health	Enterprise Data & Digital Platform	Strategic (sustainment)	Line 1 A-12 B5.7.8	Line 1 A-12 B5.7.8
Enterprise Mobility Management	Information Protection & Security	Strategic	Line 17 A-12 B5.7.6	Line 12 A-12 B5.7.6
Enterprise Monitoring Licensing Renewal	Infrastructure Operations	Sustainment	Line 6 A-12 B5.7.6	Line 8 A-12 B5.7.7
Enterprise Monitoring Strategy Implementation	Infrastructure Operations	Sustainment	Line 40 A-12 B5.7.7	Line 42 A-12 B5.7.7
EOL - Linux Return to Health	Plant & Field	Return-to-Health	Line 25 A-12 B5.7.4	-
eSOMS CORA Access Integration	Plant & Field	Return-to-Health	Line 26 A-12 B5.7.4	-
External Secure File Transfer Replacement	Infrastructure Operations	Strategic	Line 41 A-12 B5.7.7	Line 43 A-12 B5.7.7
Field Service Edge (FSE) Replacement – ClickSoft	Plant & Field	Return-to-Health	Line 24 A-12 B5.7.4	-

Line
No.

Project Name	Portfolio	Category	U-21860 Exhibit Reference	U-21534 Exhibit Reference
Field Service Management-ClickSoft for EFO (Electric Field Operations)	Plant & Field	Strategic	Line 35 A-12 B5.7.4	Line 31 A-12 B5.7.4
Firewall Threat Protection	Infrastructure Operations	Strategic	Line 42 A-12 B5.7.7	Line 44 A-12 B5.7.7
Fuel Supply-Plant Fuel Management System	Plant & Field	Return-to-Health	Line 27 A-12 B5.7.4	Line 23 A-12 B5.7.4
Industrial Hygiene	Corp Apps	Strategic	Line 16 A-12 B5.7.1	-
IT Application Environments Enhancements	Customer Service	IT Enhancements	Line 42 A-12 B5.7.3	Line 22 A-12 B5.7.3 (Hatsios)
Load Balancer Asset Health and Re-Engineering	Infrastructure Operations	Return-to-Health	Line 20 A-12 B5.7.7	Line 21 A-12 B5.7.7
Maximo HSE Support	Plant & Field	Strategic	Line 38 A-12 B5.7.4	Line 34 A-12 B5.7.4
Maximo Platform Program	Plant & Field	Return-to-Health	Line 28 A-12 B5.7.4	Line 24 A-12 B5.7.4
Meter Data Management (MDM) Consolidation	Plant & Field	Return-to-Health	Line 29 A-12 B5.7.4	Line 25 A-12 B5.7.4
MIGP Large Customer Prepayment	Customer Service	Regulatory/ Compliance	Line 3 A-12 B5.7.2	Line 10 A-12 B5.7.3 (Hatsios)
Migrate IVR to the Cloud	Customer Service	Return-to-Health	Line 35 A-12 B5.7.2	Line 23 A-12 B5.7.2
Modernize Disaster Recovery Tools	Infrastructure Operations	Return-to-Health	Line 22 A-12 B5.7.7	Line 23 A-12 B5.7.7

Line
No.

Project Name	Portfolio	Category	U-21860 Exhibit Reference	U-21534 Exhibit Reference
Organizational Management Optimization	Corporate Applications	Strategic	Line 17 A-12 B5.7.1	Line 17 A-12 B5.7.1
PCI Compliance	Customer Service	Regulatory/ Compliance	Line 7 A-12 B5.7.2	Line 12 A-12 B5.7.3 (Hatsios)
Plant & Field Document Repository	Plant & Field	Return-to-Health	Line 31 A-12 B5.7.4	Line 27 A-12 B5.7.4
Powerley Customer Platform Application Health	Customer Service	Sustainment	Line 24 A-12 B5.7.2	Line 12 A-12 B5.7.2
Recovery Manager for AD-Disaster Recovery Edition	Information Protection & Security	Strategic	Line 19 A-12 B5.7.6	Line 16 A-12 B5.7.6
Replace DO Lines - SOC Radio	Plant & Field	Return-to-Health	Line 32 A-12 B5.7.4	Line 28 A-12 B5.7.4
SIP in Call Center	Customer Service	Strategic	Line 55 A-12 B5.7.2	Line 45 A-12 B5.7.3 (Hatsios)
Storm Cloud	Infrastructure Operations	Strategic	Line 44 A-12 B5.7.7	Line 47 A-12 B5.7.7
Storm Resiliency	Plant & Field	Sustainment	Line 17 A-12 B5.7.4	-
Storm Simulation Lab	Plant & Field	Strategic	Line 40 A-12 B5.7.4	Line 37 A-12 B5.7.4
Supervisory Control and Data Acquisition (SCADA) System Improvement	Plant & Field	Sustainment	Line 16 A-12 B5.7.4	Line 15 A-12 B5.7.4
Time of Day	Customer Service	Regulatory/ Compliance	Line 10 A-12	Line 10 A-12

Line No.

Project Name	Portfolio	Category	U-21860 Exhibit Reference	U-21534 Exhibit Reference
			5.7.2	B5.7.2

VI. IT Capital Investment Details

Q57. What information is contained in this section of your testimony?

A57. As noted above, the information provided in the Company's Part III submission provides a detailed overview of IT capital investments organized into the IT Portfolios and Categories that I discuss in my testimony. This section of my testimony provides summaries of each of those investments. Within the Portfolios, the investments are organized by the investment Categories and appear in the same order as they do in the corresponding capital Exhibit A-12 Schedules B5.7.1 through B5.7.9. The business case executive summaries for these investments are provided in Exhibit A-24, Schedule N1.

A. Shared IT

Q58. Please recall how the Shared IT Portfolio investments are organized.

A58. The Shared IT Portfolio investments fall into one of five Sub-Portfolios: (a) Information Technology for IT; (b) Information Protection Security; (c) Infrastructure Operations; (d) Enterprise Data Analytics

1. Information Technology for Information Technology (IT for IT)

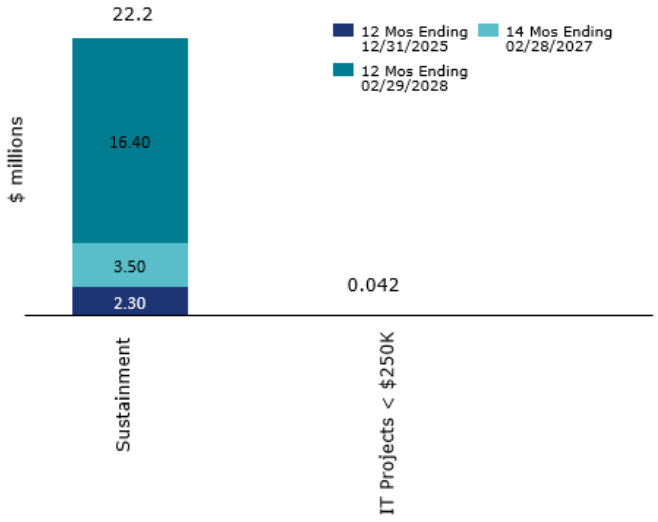
Q59. What are the projected costs for investments in IT for IT Sub-Portfolio?

A59. As reflected on line 5 of Exhibit A-12 Schedule B5.7, page 1, capital expenditures for IT for IT total $2.4 million for the historical test year ended December 31, 2025,

Line No.

1 $3.5 million in the bridge period (for the 14 months ending February 28, 2027), and
2 $16.4 million for the projected test period ending February 29, 2028.

3 The synopsis below generally provides the total spend for each line item the
4 Company requests in this rate case and the details regarding breakout by historical
5 period, projected bridge period, and projected test period, are each laid out in
6 Exhibit A-12, Schedule B5.7.5, in columns d, g and h, respectively. Figure 6
7 represents a high-level view of capital allocation within the Sub-Portfolio.
8
9 Figure 6 IT for IT investment



10

Line No.

1 a) Sustainment

2 **Q60. Please explain the IT for IT Sub-Portfolio investment in the Sustainment**
3 **category.**

4 A60. The Company will invest $19.9 million in the Sustainment category over the 26
5 months ending February 29, 2028, and has a historical spend of $2.3 million in
6 2025, as shown on lines 1-3 of Exhibit A-12, Schedule B5.7.5.

7 (1) IT for IT Application Health

8 The Company is seeking recovery for $5.2 million in the IT for IT Application
9 Health project over the 26 months ending February 29, 2028, and the historical
10 spend of $2.3 million in 2025, as shown on line 1 of Exhibit A-12, Schedule B5.7.5.
11 This investment represents an ongoing annual commitment to ensure the reliability,
12 stability, and continuous enhancement of the Company's IT Services Platform. The
13 project includes necessary production upgrades and improvements to core
14 enterprise tools, including ServiceNow, GitHub, and Azure DevOps.
15
16 Applications receive support provided by the vendor and regular upgrades to
17 mitigate security vulnerabilities. Annually, the Company completes version
18 upgrades (two annually for ServiceNow and as made available by providing
19 vendors for other applications). This project enhances workflows to improve
20 efficiency, adds new items to the service catalog to take advantage of the
21 ServiceNow solution to improve efficiency, enables automations, extends
22 discovery and event management to reduce unplanned outages, and manages
23 vulnerability identification and remediation. ServiceNow is essential to the

Line No.

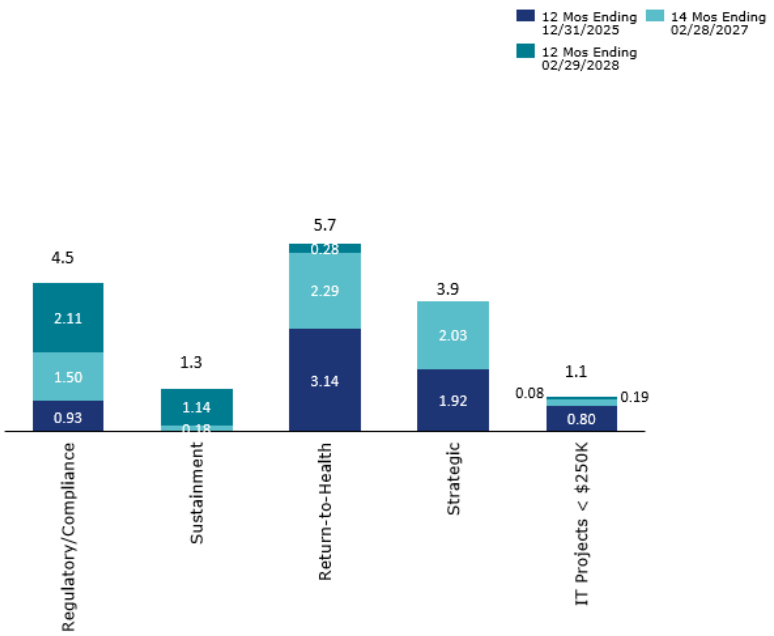
1 Company's IT governance and control and a critical tool for supporting Sarbanes-
2 Oxley (SOX) and PCI testing.
3
4 The Company reports spending $2.6 million less over 24 months ending December
5 31, 2026 than that approved for recovery per Case No. U-21860 Final Order,
6 primarily due to license renewal timing changes. In 2025, the project exceeded the
7 approved amount by $0.8 million due to vendor cost increases and a 10%
8 disallowance. In 2026, $4.0 million in license costs were restructured under a multi-
9 year agreement, offset by a $0.7 million level 3 disallowance. The ServiceNow
10 Application License Renewal is now identified as a separate project, as described
11 in Section VI.A.1.a.(3). See Exhibit A-24, Schedule N3 Revised Lines 1 – 4 for
12 additional project details.
13
14 (2) IT for IT Tools
15 The Company is seeking recovery for $1.2 million in the IT for IT Tools project
16 over the 26 months ending February 29, 2028, as shown on line 2 of Exhibit A-12,
17 Schedule B5.7.5.
18
19 This project represents the Company's investment in sustaining the enterprise tools
20 that underpin DTE's IT governance, compliance, and identity-management
21 functions. These tools support essential functions such as identity and access
22 management, SOX compliance activities, security remediation, and integration
23 across incident, release, and software development processes. The initiative ensures
24 that core platforms, such as SailPoint and other IT4IT governance tools, remain
25 secure, current, and fully integrated with the Company's access, compliance, and

Line No.

1 IT operations workflows. See Exhibit A-24, Schedule N3 Revised, Lines 5 – 7 for
2 additional project details.
3
4 (3) ServiceNow Application License Renewal
5 The Company is seeking recovery for $13.5 million in the ServiceNow Application
6 License Renewal project over the 26 months ending February 29, 2028, as shown
7 on line 3 of Exhibit A-12, Schedule B5.7.5.
8 The ServiceNow software license agreement is due for renewal at the conclusion
9 of its current three-year term. ServiceNow remains a foundational enterprise
10 platform supporting IT service management, demand and portfolio management,
11 asset management across multiple IT and business functions. The platform is
12 deeply integrated into day-to-day operational processes and serves as the system of
13 record for request intake, approvals, incident and problem management, and
14 compliance-driven workflows. Renewal of the ServiceNow license is necessary to
15 ensure continuity of operations and avoid disruption to business-critical services.
16 Failure to renew would result in the loss of access to core operational capabilities,
17 negatively impacting service delivery, compliance obligations, and productivity
18 across multiple teams. See Exhibit A-24, Schedule N3 Revised, Line 8 for
19 additional project details.
20
21 2. Information Protection & Security
22 **Q61. What are the projected costs for investments in the Information Protection &**
23 **Security (IPS) Sub-Portfolio?**
24 A61. As reflected on line 6 of Exhibit A-12 Schedule B5.7, page 1, capital expenditures
25 for IPS total $6.8 million for the historical period ended December 31, 2025, $6.2

Line No.

1 million in the bridge period (for the 14 months ending February 28, 2027), and $3.6
2 million for the projected test period ending February 29, 2028.
3
4 The synopses below generally provide the total spend for each line item the
5 Company requests in this rate case. The details regarding breakout by historical
6 period, projected bridge period, and projected test period, are each laid out in
7 Exhibit A-12, Schedule B5.7.6 in columns (d), (g), and (h), respectively. Figure 7
8 represents a high-level view of capital allocation within the Sub-Portfolio.
9
10 Figure 7 IPS – IT Investment
11



12

Line No.

a) Regulatory/Compliance

Q62. What is the IPS Sub-Portfolio investment in the Regulatory/Compliance category?

A62. The Company is seeking recovery for $3.6 million in the Regulatory/Compliance category over the 26 months ending February 29, 2028, and the historical spend of $0.9 million in 2025 as shown on lines 1 to 4 of Exhibit A-12, Schedule B5.7.6. These investments are described below.

(1) Advanced Privileged Access Management - NERC

The Company is seeking recovery for $1.1 million in the Advanced Privilege Access Management - NERC project over the 12 months ending February 29, 2028, as shown on line 1 of Exhibit A-12, Schedule B5.7.6.

This investment addresses the Company's need to sustain and enhance privileged access controls for systems subject to NERC reliability and cybersecurity requirements. The project supports the transition from the Company's existing Privileged Access Management (PAM) solution, which has reached end-of-life, to a new on-premise PAM platform designed to meet evolving regulatory, infrastructure, and security requirements applicable to NERC-regulated environments. Changes in the PAM vendor market, combined with increased infrastructure demands and reliance on vendor-provided professional services, have materially increased the cost and risk of maintaining the existing solution. Continued operation of the current platform would require additional infrastructure investment while providing limited ability to adapt to updated compliance and audit expectations. The proposed on-premise solution provides equivalent core PAM

Line No.

1 functionality while introducing enhanced security and compliance capabilities
2 tailored to regulated operational technology and critical infrastructure
3 environments. These capabilities include real-time session monitoring, just-in-time
4 privileged access elevation, integrated compliance reporting aligned with NERC,
5 SOX, and PCI standards, and direct integration with ServiceNow for access
6 governance and change management. See Exhibit A-24, Schedule N3 Revised,
7 lines 9,10 for additional project details.
8
9 (2) Communication Compliance and Data Loss Prevention (DLP)
10 The Company is seeking recovery for $0.18 million in the Communication
11 Compliance and Data Loss Prevention (DLP) project over the 14 months ending
12 February 28, 2027, and has a historical expenditure of $0.13 million in 2025, as
13 shown on line 2 of Exhibit A-12, Schedule B5.7.6.
14
15 The Company's current Data Loss Prevention and Communication Compliance
16 capabilities are primarily email-focused and depend significantly on manual,
17 reactive review processes. Coverage across modern collaboration platforms is
18 limited or inconsistently applied, and the existing deployment includes minimal
19 automated, preventative enforcement. While these controls support baseline
20 compliance expectations, they do not provide the level of automation, consistency,
21 or platform breadth necessary for proactive, enterprise-wide monitoring and
22 enforcement. Deployment of Data Loss Prevention is informed by multiple external
23 compliance obligations, including PCI DSS, NERC CIP, Sarbanes-Oxley, HIPAA,
24 and applicable Michigan data protection statutes. These frameworks require
25 organizations to safeguard sensitive information, monitor data movement, and

Line No.

1 maintain auditable controls to support regulatory oversight. A mature DLP
2 capability provides standardized, preventative controls that enable consistent
3 monitoring and enforcement across modern communication and collaboration
4 platforms, while also supporting auditability and regulatory review.
5
6 In the current state, the Company's DLP deployment is primarily limited to
7 outbound email and does not provide comprehensive or preventative protection,
8 across modern enterprise collaboration platforms. Microsoft Teams, SharePoint,
9 OneDrive, collaboration-based attachments, Copilot interactions, and third-party
10 integrated applications rely largely on manual, after-the-fact review and
11 enforcement rather than automated, policy-driven controls. These coverage
12 limitations and reliance on reactive processes are documented in internal regulatory
13 responses and project materials and underscore the need to expand and mature DLP
14 capabilities to support consistent, enterprise-wide data protection. Maturing Data
15 Loss Prevention (DLP) is now necessary because both the regulatory environment
16 and the threat landscape have reached an inflection point, which no longer tolerates
17 reactive or manually enforced controls. External oversight frameworks applicable
18 to DTE—including PCI DSS, NERC CIP, Sarbanes-Oxley, HIPAA, and Michigan
19 data protection statutes—are increasingly explicit in their expectation of
20 demonstrable, preventative, and consistently enforced safeguards, particularly
21 across cloud-based email and collaboration platforms that now represent the
22 primary surface for sensitive data movement. At the same time, cyber threat activity
23 targeting critical infrastructure has accelerated and shifted toward exploitation of
24 these same platforms, making delayed or partial controls materially riskier.
25 Continuing to rely on baseline DLP capabilities that are largely manual and reactive

Line No.

1 increases the likelihood of audit findings, regulatory scrutiny, and operational
2 exposure as expectations continue to rise. Advancing to automated, policy-driven
3 enforcement at this stage allows DTE to proactively align with regulator
4 expectations, reduce cumulative compliance risk, and demonstrate responsible
5 stewardship of sensitive data before gaps are identified externally. By
6 implementing now, DTE can stay ahead of evolving requirements and threat
7 realities, rather than responding after deficiencies have already been observed,
8 exposed and potentially taken advantage of.
9
10 The Company reports a variance of $0.3 million more over 24 months ending
11 December 31, 2026 than that approved for recovery per Case No. U-21860 Final
12 Order due to the full disallowance of this work. The Company requests
13 consideration of approval for this investment in light of the critical need for the
14 capabilities described above and their importance to the Company's data
15 protection, compliance, and information governance objectives. See Exhibit A-24,
16 Schedule N3 Revised, Lines 11, 12 for additional project details.
17
18 (3) Non-Windows and Mobile Endpoint Protection
19 The Company is seeking recovery for $0.2 million in the Non-Windows and Mobile
20 Endpoint Protection project over the 26 months ending February 29, 2028, and has
21 a historical spend of $0.08 million as shown on line 3 of Exhibit A-12, Schedule
22 B5.7.6.
23
24 This investment supports strengthening endpoint security by fully deploying
25 Microsoft Defender across corporate-owned assets that are not currently protected.

Line No.

1 The effort standardizes advanced threat protection across shared enterprise
2 infrastructure which supports both gas and electric operations, including servers,
3 mobile devices, and Mac endpoints.
4
5 In 2025, the program focused on onboarding non-Windows servers into Microsoft
6 Defender to address gaps in endpoint visibility and protection. In 2027, the project
7 expands Defender coverage to all corporate-owned mobile devices, implementing
8 mobile-specific security controls such as antivirus protection, application blocking,
9 and mobile threat defense for iOS and Android platforms. This phase also includes
10 the onboarding of Azure cloud servers, which had been within the original 2025
11 project scope.
12
13 The Company reports a $0.3 million less over 24 months ending December 31,
14 2026 than that approved for recovery per Case No. U-21860 Final Order reflecting
15 scope deferral to 2027 to align with enterprise portfolio priorities. See Exhibit A-
16 24, Schedule N3 Revised, Lines 13,14 for additional project details.
17
18 (4) Patch and Certification Management Program
19 The Company is seeking recovery for $2.1 million in the Patch and Certification
20 Management Program project over the 26 months ending February 29, 2028, and
21 has a historical spend of $0.7 million as shown on line 4 of Exhibit A-12, Schedule
22 B5.7.6.
23
24 The Company will continue to invest in incremental cybersecurity enhancements
25 that strengthen certificate lifecycle management, vulnerability governance, and

Line No.

1 integration of existing security tools. These activities are structured as a multi-year
2 effort to modernize security operations, improve compliance visibility, and reduce
3 cyber risk through greater automation and coordination among existing DTE
4 platforms. In 2027, the Company plans to further expand Secure Socket layers
5 (SSL)/ Transport Layer security (TLS) certificate management across additional
6 corporate network segments and begin onboarding an initial subset of Operational
7 Technology (OT) assets. Parallel activities will include continued onboarding of
8 applications into Microsoft Defender Vulnerability Management (MDVM),
9 progress toward automated patching workflows, and implementation of Web
10 Application Firewalls (WAF) for 5–10 Azure/Entra web applications. This
11 investment will also continue to refine ServiceNow configurations to support
12 consistent certificate and vulnerability tracking and remediation processes.
13 Consistent with prior years, this work builds on existing technology investments
14 and focuses funding on implementation support and expertise transfer. See Exhibit
15 A-24, Schedule N3 Revised, Lines 15 – 17 for additional project details.
16
17 b) Sustainment
18 **Q63. Please explain the IPS Sub-Portfolio investment in the Sustainment category.**
19 A63. The Company will invest $1.3 million in the Sustainment category over the 26
20 months ending February 29, 2028, as shown on lines 5 and 6 of Exhibit A-12,
21 Schedule B5.7.6.

Line No.

1 (1) Cloud and Endpoint Security Application Health

2 The Company is seeking recovery for $0.7 million in the Cloud and Endpoint
3 Security Application Health project over the 26 months ending February 29, 2028,
4 as shown on line 5 of Exhibit A-12, Schedule B5.7.6.
5
6 The Company's continued adoption of cloud-based technologies and support for
7 remote work have expanded the number of connected endpoints, applications, and
8 communication channels across the organization. While these capabilities improve
9 operational efficiency, they also increase system complexity and elevate exposure
10 to cybersecurity, data protection, and compliance risks, including ransomware,
11 phishing, credential compromise, and non-compliance with applicable regulatory
12 requirements. The Company has evaluated, deployed, and integrated core security
13 capabilities across its production environment, where they are operating as intended
14 and meeting baseline requirements for performance, security, and compliance.
15 These solutions are subject to periodic quality management and audit reviews, to
16 ensure continued alignment with the Company's security posture.
17
18 This investment is required to sustain the effectiveness of these controls, as the
19 operating environment and threat landscape evolve. Key capabilities, including
20 Endpoint Privilege Management, Enterprise Mobility Management, Endpoint
21 Protection, and Data Loss Prevention, work together to maintain least-privilege
22 access, secure corporate and mobile devices, protect workloads from advanced
23 threats, and prevent unauthorized disclosure of sensitive information. See Exhibit
24 A-24, Schedule N3 Revised, Lines 18, 19 for additional project details.

Line No.

(2) Security Information & Event Management (SIEM) Storage Application Management

The Company is seeking recovery for $0.6 million in the Security Information & Event Management (SIEM) Storage Application Management project over the 26 months ending February 29, 2028 as shown on line 6 of Exhibit A-12, Schedule B5.7.6.

This investment supports the continued operation of DTE's Security Information and Event Management (SIEM) platform, by providing additional storage capacity as existing hardware approaches its operational limits. This enhancement is necessary to sustain support for the Company's expanding Operational Technology (OT) environment. SIEM provides real-time monitoring and analysis of security events, generates alerts for investigation, and retains security logs required for regulatory compliance and auditing, including requirements under NERC, PCI, SEC, SOX, and TSA. These regulations mandate the logging and retention of security events. Without an operational SIEM, required logging would not occur, placing the Company in non-compliance. SIEM is a critical component of the Company's cybersecurity posture, enabling the monitoring and detection of cybersecurity threats. Failure to detect cybersecurity incidents could expose the Company to financial, reputational, and customer data integrity risks. See Exhibit A-24, Schedule N3 Revised, Lines 20, 21 for additional project details.

c) Return-to-Health

Q64. What is the IPS Sub-Portfolio investment in the Return-to-Health category?

Line No.

1 A64. The Company is seeking recovery for $2.6 million in the Return-to-Health category
2 over the 26 months ending February 29, 2028, and the historical spend of $3.1
3 million in 2025, as shown in lines 7 to 9 of the Capital Expenditures – Exhibit A-
4 12, Schedule B5.7.6. These investments are described below.
5
6 (1) Advanced Privileged Access Management
7 The Company is seeking recovery for $2.0 million in the Advanced Privileged
8 Access Management project over the 26 months ending February 29, 2028, and has
9 a historical spend of $2.84 million in 2025, as shown on line 7 of Exhibit A-12,
10 Schedule B5.7.6.
11
12 This investment responds to changes in the Privileged Access Management market
13 and an updated understanding of infrastructure and professional service
14 requirements necessary to protect privileged accounts across the Company's
15 enterprise and cloud environments. The Company's existing PAM solution has
16 reached end-of-life and no longer provides sufficient scalability, visibility, or cost
17 efficiency to support current operational and security needs.
18
19 The project implements a new on-premise PAM solution to secure privileged access
20 associated with the Company's cloud platforms and enterprise systems. While
21 maintaining the core functionality of the legacy platform, the new solution enables
22 expanded capabilities required to address evolving cybersecurity risks and
23 enterprise use cases. These include real-time monitoring and inventory of
24 privileged accounts, Active Directory bridging, just-in-time and just-enough access
25 elevation, out-of-the-box compliance reporting for NERC, SOX, and PCI,

Line No.

1 behavioral analytics, geofencing, and integrated change management through
2 ServiceNow.
3
4 The Company reports a variance of $1.0 million more over 24 months ending
5 December 31, 2026 than that approved for recovery per Case No. U-21860 Final
6 Order. Of this amount, $0.4 million is due to 10% Level 3 disallowance in 2025
7 and 2026. The remaining $0.6 million reflects the incremental costs to support the
8 pre- and post-implementation audits conducted by PwC in conjunction with the
9 vendor that required additional vendor support and resource support. See Exhibit
10 A-24, Schedule N3 Revised, Lines 22, 23 for additional project details.
11
12 (2) Cybersecurity Defense Center (CSDC) Growth and Lifecycle
13 Management
14 The Company is seeking recovery for $0.6 million in the Cybersecurity Defense
15 Center (CSDC) Growth and Life Cycle Management project over the 26 months
16 ending February 29, 2028, and the historical spend of $0.02 million in 2025, as
17 shown on line 9 of Exhibit A-12, Schedule B5.7.6.
18
19 This investment supports ongoing cybersecurity monitoring and hardware lifecycle
20 management necessary to maintain effective detection of and defense against
21 threats to the Company's cyber assets. The project leverages existing tools and
22 processes to preserve the Company's ability to monitor and respond to
23 cybersecurity threats and incidents, including the replacement of network taps and
24 sensors to ensure continued network visibility. In 2027 and 2028, the Company will
25 replace network taps, vulnerability scanners, syslog servers, and analyst

Line No.

1 workstations as these assets reach the end of their useful life, ensuring reliable log
2 collection, analysis, and incident response capabilities.
3
4 The Company reports a $0.25 million less over 24 months ending December 31,
5 2026 than that approved for recovery per Case No. U-21860 Final Order due to the
6 acceleration of planned cybersecurity asset replacement procurements from 2025
7 into 2024. See Exhibit A-24, Schedule N3 Revised, Lines 25 – 28 for additional
8 project details.
9
10 d) Strategic
11 **Q65. What is the IPS Sub-Portfolio investment in the Strategic category?**
12 A65. The Company is seeking recovery for $2.0 million in the Strategic category over
13 the 12 months ending December 31, 2026, and the historical spend of $1.9 million
14 in 2025, as shown in lines 10-12 of the Capital Expenditures – Exhibit A-12,
15 Schedule B5.7.6. These investments are described below.
16
17 (1) Automated Provisioning
18 The Company is seeking recovery for $1.5 million in the Automated Provisioning
19 project over the 26 months ending February 29, 2028, and the historical spend of
20 $1.4 million in 2025, as shown on line 10 of Exhibit A-12, Schedule B5.7.6.
21
22 This project replaces the Company's legacy Identity and Access Management
23 (IAM) solution, completing implementation and retiring the legacy tool. The
24 project supports key processes including HR onboarding, user access reviews,
25 compliance audits, and role-based access implementation, streamlining access

Line No.

1 management while strengthening system security. From 2023 through 2026, the
2 Company is onboarding additional Sarbanes-Oxley (SOX) applications,
3 automating workflows, and integrating with Privileged Access Management and
4 Single Sign-On solutions to improve security, user experience, and compliance
5 with SOX requirements.
6
7 The Company reports a variance of $1.2 million more over 24 months ending
8 December 31, 2026 than that approved for recovery per Case No. U-21860 Final
9 Order. Of this amount, $0.2 million is due to the 10% disallowance applied in 2025
10 and 2026 per final order Case No. U-21860. The remaining $1.0 million supports
11 additional design, development, testing, and coordination activities required to
12 incorporate Provisioning User Access Review (PUAR) functionality, resulting in
13 incremental labor and professional service costs necessary to support the project's
14 security, compliance, and access governance objectives. See Exhibit A-24,
15 Schedule N3 Revised, Lines 29, 30 for additional project details.
16
17 (2) Cyber Resilient Offline Data Recovery
18 The Company is seeking recovery for $0.5 million in the Cyber Resilient Offline
19 Data Recovery project over the 14 months ending February 28, 2027 as shown on
20 line 12 of Exhibit A-12, Schedule B5.7.6.
21
22 The Ransomware Recovery project has been renamed as the Cyber Resilient
23 Offline Data Recovery. This project establishes a secure cyber recovery capability
24 to restore DTE's most critical operational systems and data in the event of a cyber
25 incident, including ransomware. It implements a commercial data recovery solution

Line No.

and protected data vault with stronger controls than standard backups, using immutable backups for both on-premise and cloud-hosted critical data and supporting automated infrastructure, server, and file or mass data restores. The solution includes an isolated recovery environment and validated recovery processes for critical power generation and gas distribution systems, including Gas SCADA, to ensure reliable, secure restoration of operations.

The Company reports a variance of $0.4 million less over 24 months ending December 31, 2026 than that approved for recovery per Case No. U-21860 Final Order due to deferral following re-evaluation of project scope with other organizational priorities. See Exhibit A-24, Schedule N3 Revised, Line 32 for additional project details.

3. Infrastructure Operations

Q66. What are the projected costs for investments in the Infrastructure Operations Sub-Portfolio?

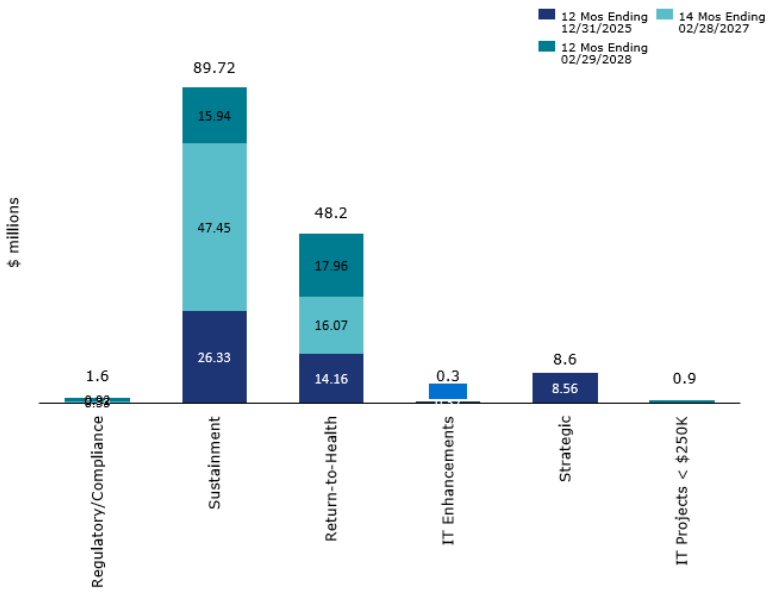
A66. As reflected on Line 7 of Exhibit A-12 Schedule B5.7, page 1, capital expenditures for Infrastructure Operations total $49.9 million for the historical test year ended December 31, 2025, $63.8 million in the bridge period (for the 14 months ending February 28, 2027), and $35.5 million for the projected test period ending February 29, 2028.

The synopses below generally provide the total spend for each line item the Company requests in this rate case and the details regarding breakout by historical period, projected bridge period, and projected test period, are each laid out in

Line No.

Exhibit A-12, Schedule B5.7.7, in columns d, g and h, respectively. Figure 8 below represents a high-level view of capital allocation within the Sub-Portfolio.

Figure 8 Infrastructure Operations – IT Investment



a) Regulatory/Compliance

Q67. What is the Infrastructure Operations Sub-Portfolio investment in the Regulatory/Compliance category?

A67. The Company is seeking recovery for $1.3 million in the Regulatory/ Compliance category over the 26 months ending February 29, 2028, and the historical spend of $0.3 million in 2025 as shown on lines 1-2 of the Capital Expenditures – Exhibit A-12, Schedule B5.7.7. These investments are described below.

(1) Government Cloud Foundation

The Company is seeking recovery for $0.6 million in the Government Cloud Foundation project in the Regulatory/Compliance category of the Infrastructure

Line No.

1 Operations Sub-Portfolio over the 26 months ending February 29, 2028 as shown
2 on line 1 of the Capital Expenditures – Exhibit A-12, Schedule B5.7.7.
3 This investment supports the Company's need for a secure and compliant
4 Government Cloud environment to host regulated workloads subject to U.S.-only
5 data residency, screened-personnel access, and FedRAMP-aligned security
6 requirements. The investment establishes a single, enterprise-sanctioned
7 Government Cloud foundation, either Azure Government or AWS GovCloud,
8 consistent with the Company's cloud strategy for regulated workloads. The
9 investment provides standardized identity, secure networking, regulated landing
10 zones, policy-based security controls, centralized logging and monitoring, and
11 controlled onboarding pathways to ensure consistent application of security and
12 compliance requirements. In the absence of a unified Government Cloud
13 foundation, the Company relies on on-premises environments or duplicative
14 controls, increasing risk, cost, and operational complexity. This investment reduces
15 regulatory and operational risk while improving reliability and delivery efficiency,
16 while preserving flexibility for commercial cloud use cases. See Exhibit A-24,
17 Schedule N3 Revised, Line 33 for additional project details.
18
19 (2) Tower and Lighting Inspections and Repairs
20 The Company is seeking recovery for $0.6 million in the Tower and Lighting
21 Inspections and Repairs project in the Regulatory/Compliance category of the
22 Infrastructure Operations Sub-Portfolio over the 26 months ending February 29,
23 2028, and the historical spend of $0.3 million in 2025 as shown on line 2 of the
24 Capital Expenditures – Exhibit A-12, Schedule B5.7.7.
25

Line No.

1 The Tower and Lighting Inspections and Repairs project is an annual effort that
2 evaluates the integrity of the physical towers that carry the DTE network
3 telecommunications lines and the real estate upon which the towers are built. These
4 towers are used to provide reliable, efficient, and redundant network systems that
5 are used by DTE IT and DTE Business Units in support of customers. Federal
6 Communications Commission (FCC) regulations ensure the capability, security,
7 and safety of these lines in the transmission of DTE data. See Exhibit A-24,
8 Schedule N3 Revised, Lines 34 - 37 for additional project details.
9
10 b) Sustainment
11 **Q68. What is the Infrastructure Operations Sub-Portfolio investment in the**
12 **Sustainment category?**
13 A68. The Company is seeking recovery for invest $63.4 million in the Sustainment
14 category of the Infrastructure Operations Sub-Portfolio over the 26 months ending
15 February 29, 2028, and the historical spend of $26.3 million over 12 months ending
16 December 31, 2025, as shown in lines 3 to 17 of the Capital Expenditures – Exhibit
17 A-12, Schedule B5.7.7. These investments are described below.
18
19 (1) Backup Environmental Growth
20 The Company is seeking recovery for $1.1 million in the Backup Environmental
21 Growth project over the 26 months ending February 29, 2028, and the historical
22 spend of $0.5 million in 2025, as shown on line 3 of Exhibit A-12, Schedule B5.7.7.
23
24 The Backup Environmental Growth investment is an ongoing annual initiative
25 required to meet business data storage, access, and retention requirements. This

Line No.

1 project replaces aged backup and storage infrastructure, including storage arrays,
2 backup servers, repositories, and associated capacity with current, scalable
3 technology that supports DTE's growing data needs through 2028. The backup
4 environment increases approximately 18% each year, requiring corresponding
5 increases in capacity to maintain compliance with data access and retention
6 policies. Without these investments, data retention, recoverability, and business
7 continuity would be at risk, directly impacting DTE's ability to meet customer and
8 operational requirements. The Company reports a variance of $0.2 million more
9 over 24 months ending December 31, 2026 than that approved for recovery per
10 Case No. U-21860 Final Order due to a 20% estimate level disallowance. However,
11 this investment is necessary to complete the migration and platform transition
12 activities described above. Allowing recovery of the full amount avoids prolonging
13 reliance on unsupported tools and the associated operational inefficiencies and
14 security risks. See Exhibit A-24, Schedule N3 Revised, Lines 38-41 for additional
15 project details.
16
17 (2) Cloud Automation Tools License Renewal
18 The Company is seeking recovery for $1.1 million in the Cloud Automation Tool
19 License Renewal project over the 14 months ending February 28, 2027 as shown
20 on line 4 of Exhibit A-12, Schedule B5.7.7.
21
22 This investment renews licenses for Terraform, Domain Name Server (DNS),
23 Device42, Infoblox, and LucidSuite—core automation tools that enable DTE's
24 cloud foundation. These tools automate infrastructure provisioning, enforce policy-
25 as-code for compliance and security, monitor cloud spend and security posture, and

Line No.

1 support dynamic scalability and resiliency for storm-critical applications. Without
2 renewed licenses, these capabilities would be compromised, increasing the risk of
3 uncontrolled cloud costs, inefficient operations, and weakened security as DTE's
4 cloud environment continues to expand. See Exhibit A-24, Schedule N3 Revised,
5 Line 42 for additional project details.
6
7 (3) Cloud Program Application Health
8 The Company is seeking recovery for $3.1 million in the Cloud Program
9 Application Health project over the 26 months ending February 29, 2028 as shown
10 on line 5 of Exhibit A-12, Schedule B5.7.7.
11
12 This investment sustains the Storm Cloud Gen 2 platform using Infrastructure as
13 Code (IaC) automation for scalable, secure, and resilient infrastructure that supports
14 storm-critical and customer-facing applications. This initiative delivers operational
15 efficiencies through automated, auditable deployments that minimize human error,
16 accelerate service delivery, and reduce long-term infrastructure costs. This
17 investment follows a phased maturity approach that incrementally matures platform
18 capabilities. In 2026, the focus is on establishing foundational functions, including
19 baseline environment alignment, reusable Kubernetes and analytics components,
20 integrated logging and metrics, drift detection, resource controls, onboarding
21 materials, and CI/CD integration with IT service management processes. In 2027,
22 the work will focus on advancing platform governance and automation through the
23 implementation of a centralized policy engine, Infrastructure-as-Code (Iac)
24 compliance scanning, expanded monitoring and security automation, standardized
25 modular infrastructure patterns, an artifact registry, additional training, and cloud

1 cost optimization enhancements. Additionally, the project aims to migrate the
2 existing Virtual Private Network between DTE's data centers and the Azure cloud
3 with the Azure ExpressRoute gateway. The Azure ExpressRoute gateway peering
4 points facilitate private connections between client networks and Microsoft Azure
5 cloud datacenters with resilient routes. This capability provides a low-latency
6 Microsoft backbone network that forms a highly resilient connection. All the
7 applications that are currently leveraging the VPN connectivity between the on-
8 prem and cloud would be migrated to the Azure ExpressRoute gateway as a part of
9 this effort. By 2028, the initiative extends these capabilities to hybrid and multi-
10 cloud environments through hybrid IaC development, federated governance,
11 business aligned dashboards, and domain specific templates for data science and
12 machine learning workloads. See Exhibit A-24, Schedule N3 Revised, Lines 43- 45
13 for additional project details.
14
15 (4) Collaboration Application Health
16 The Company is seeking recovery for $3.9 million in the Collaboration Application
17 Health project over the 26 months ending February 29, 2028, and has a historical
18 spend of $3.5 million in 2025, as shown on line 6 of Exhibit A-12, Schedule B5.7.7.
19
20 This project is an annual investment to sustain the collaboration platform,
21 implement hardware and environment upgrades, security patches, and adopt both
22 major and minor software releases to avoid or account for software version
23 obsolescence. The collaboration platform is a group of systems that enable
24 employee productivity through collaborative communications, meetings, email,
25 calendaring, instant messaging, co-authoring, and phone calls. Improvements of

Line No.

1 this type are often critical in ensuring that system integrity is maintained allowing
2 for the timely adoption of security patches and emerging versions.
3
4 The Company reports a variance of $8.8 million less over 24 months ending
5 December 31, 2026 than that approved for recovery per Case No. U-21860 Final
6 Order. Of this amount, $1.6 million increase was due to 10% disallowance applied
7 in 2025 and 2026 as directed by final order U-21860. This was offset by a $10.4
8 million reduction associated with the removal of on-premise Microsoft Enterprise
9 Agreement license costs from this investment, which are now addressed under a
10 separate investment described in Section VI.A.3.b.9. See Exhibit A-24, Schedule
11 N3 Revised, Lines 46- 49 for additional project details.
12
13 (5) Dell Storage Hardware Refresh
14 The Company is seeking recovery for $2.3 million in the Dell Storage Hardware
15 Refresh project over the 26 months ending February 29, 2028, as shown on line 7
16 of Exhibit A-12, Schedule B5.7.7.
17
18 This investment supports the agreement that the Company must contractually
19 execute in order to ensure the continuity of enterprise storage services. This contract
20 is crucial as it affects the Company's storage capabilities, supporting all servers and
21 enterprise-wide applications hosted on them. By renewing the Dell agreement, the
22 Company can continue to meet its storage obligations critical enterprise
23 applications that host both external and internal customer data. See Exhibit A-24,
24 Schedule N3 Revised, Lines 50- 52 for additional project details.
25

Line No.

1 (6) Endpoint End of Life Electric Support Services

2 The Company is seeking recovery for $1.9 million in the Endpoint End of Life
3 Electric Support Services project over the 26 months ending February 29, 2028,
4 and a historical spend of $0.8 million in 2025, as shown on line 17 of Exhibit A-
5 12, Schedule B5.7.7.
6
7 This annual investment supports required endpoint operational services to address
8 end-user issues that impact daily work activities. The project continues the
9 Company's partnership with a third-party service provider to support endpoint asset
10 health and lifecycle management. This investment supports the deployment and
11 ongoing operation of endpoint assets purchased under the Endpoint End-of-Life
12 (EOL) program. See Exhibit A-24, Schedule N3 Revised, Lines 53-56 for
13 additional project details.
14
15 (7) Enterprise Monitoring Strategy Operational Growth

16 The Company is seeking recovery for $1.0 million in the Enterprise Monitoring
17 Strategy Operational Growth project over the 26 months ending February 29, 2028,
18 and the historical spend of $0.6 million in 2025, as shown on line 9 of Exhibit A-
19 12, Schedule B5.7.7.
20
21 The Enterprise Monitoring Strategy Operational Growth project is an annual
22 investment that supports expansion of the monitoring of critical applications,
23 infrastructure, security, services, and user experiences. This expanded monitoring
24 provides increased ability to extract and present data logs, implement real-time
25 decision-making dashboards, provide analysis of application infrastructure,

Line No.

1 security, inter-connectivity, services, and proactively respond to increased demand
2 on the IT infrastructure from processing business systems and user load.
3 See Exhibit A-24, Schedule N3 Revised, Lines 58-60 for additional project details.
4
5 (8) Field Communications Network (FCN) Growth and Upgrade
6 The Company is seeking recovery for $0.9 million in the Field Communications
7 Network (FCN) Growth and Upgrade project over the 26 months ending February
8 29, 2028, and the historical spend of $0.3 million in 2025, as shown on line 10 of
9 the Exhibit A-12, Schedule B5.7.7.
10
11 The Field Communications Network (FCN) Growth and Upgrade project is an
12 ongoing annual sustainment investment that provides redundant communication
13 and control for field devices, routers, switches, and hubs, which monitor and control
14 the bulk electric system. This program replaces devices that are reaching the end of
15 useful life, adds devices to accommodate load or geographical growth, and adds
16 functionality, automation, and redundancy to the alternate System Operations
17 Center location. Annually, this effort in both hardware and labor is required to
18 ensure the communication hardware requiring replacement, upgrade, or
19 reconfiguration meets the requirements of the business and the Company's
20 customers. See Exhibit A-24, Schedule N3 Revised, Lines 61-64 for additional
21 project details.

Line No.

1 (9) Microsoft License Renewal

2 The Company is seeking recovery for $27.5 million in the Microsoft License
3 Renewal project over the 12 months ending December 31, 2026 as shown on line
4 11 of Exhibit A-12, Schedule B5.7.7.
5
6 This investment supports the 2026 renewal of the Microsoft Enterprise Agreement,
7 which is renewed on a three-year cycle, and the continued support of the
8 Company's enterprise collaboration platform. The Microsoft 365 platform provides
9 critical enterprise functionality, including collaborative communications, meetings,
10 email, calendaring, instant messaging, co-authoring, and calling, and enables secure
11 access across multiple devices. These capabilities are essential to maintaining
12 application availability, supporting remote work, and enabling employees to
13 execute business processes efficiently. Without this investment, the Company
14 would face increased risk associated with unsupported collaboration services,
15 including reduced reliability of email, meetings, messaging, and calling, and
16 limited ability to support remote and mobile work. These impacts would adversely
17 affect business operations and workforce productivity. See Exhibit A-24, Schedule
18 N3 Revised, Lines 65 for additional project details.
19
20 (10) Network Engineering Licenses Renewals

21 The Company is seeking recovery for $2.2 million in the Network Engineering
22 Licenses Renewals project over the 14 months ending February 28, 2027 as shown
23 on line 12 of Exhibit A-12, Schedule B5.7.7.
24

Line No.

1 This investment supports the continued operation of the Company's Network and
2 Telecommunication infrastructure, which provides essential enterprise services
3 including WiFi, telephony, Wide Area Network (WAN), Local Area Network
4 (LAN), and Internet Protocol Address Management (IPAM). These services are
5 critical to the safe and reliable operation of the electric system, customer service
6 functions, and crew safety across the Company's service territory. The
7 infrastructure is delivered through strategic vendor platforms, including Cisco and
8 Infoblox, under licensing and support agreements that expire in 2026 and therefore
9 require renewal. Renewal of these agreements is necessary to maintain core
10 network services, including Domain Name System (DNS) and Dynamic Host
11 Configuration Protocol (DHCP), as the do-nothing alternative would result in a
12 breakdown of communications supporting critical systems. See Exhibit A-24,
13 Schedule N3 Revised, Line 66 for additional project details.
14
15 (11) Network Hardening and Operations
16 The Company is seeking recovery for $0.9 million in the Network Hardening and
17 Operations project over the 26 months ending February 29, 2028, and the historical
18 spend of $0.4 million in 2025, as shown on line 13 of Exhibit A-12, Schedule
19 B5.7.7.
20
21 The Network Hardening and Operations project is an annual investment that
22 supports Network Engineering services for the deployment and operation of
23 Network End-of-Life assets. The project assesses network conditions and
24 implements required hardening upgrades to maintain reliable service, with

Line No.

1 third-party support providing necessary supplemental labor. See Exhibit A-24,
2 Schedule N3 Revised, Lines 67-70 for additional project details.
3
4 (12) Palo Alto License Renewal
5 The Company is seeking recovery for $5.9 million in the Palo Alto License
6 Renewal project over the 26 months ending February 29, 2028 and the historical
7 spend of $5.8 million in 2025, as shown on line 14 of Exhibit A-12, Schedule
8 B5.7.7.
9 This investment supports the continued operation of the Company's network
10 security infrastructure in response to evolving internal and external security threats
11 across the Company's IT and OT/control networks. The Company leverages Palo
12 Alto security platforms to protect critical network assets and maintain an effective
13 security posture. Palo Alto licensing was renewed in 2025 to ensure functionality
14 and vendor support for these security assets, and the associated licensing and
15 support will expire in 2028, requiring renewal. The do-nothing alternative was
16 evaluated and rejected, as failure to renew these licenses would significantly
17 degrade the Company's network security posture. See Exhibit A-24, Schedule N3
18 Revised, Lines 71-72 for additional project details.
19
20 (13) Server Engineering Support Services
21 The Company is seeking recovery for $6.7 million in the Server Engineering
22 Support Services project over the 26 months ending February 29, 2028, and the
23 historical spend of $4.7 million 2025, as shown on line 15 of Exhibit A-12,
24 Schedule B5.7.7.

Line No.

1 This investment supports Server and Database Engineering and Operations through
2 a Managed Service Agreement that provides defined services to meet project and
3 system upgrade demands. The planned spend supports deployment of End-of-Life
4 assets and ongoing services, including project support, vulnerability management,
5 and server and database upgrades, without which the Company would be unable to
6 execute critical infrastructure work.

7 The Company reports a variance of $2.0 million more over 24 months ending
8 December 31, 2026 than that approved for recovery per Case No. U-21860 Final
9 Order. Of this amount, $0.7 million is due to the 10% disallowance in 2025 and
10 2026 as per final order U-21860. The remaining $1.3 million for additional scope
11 incurred in 2025 related to procurement of additional R730 physical servers and
12 Dell TLA warranty support. See Exhibit A-24, Schedule N3 Revised, Line 73-76
13 for additional project details.
14
15 (14) VMWare License Renewal
16 The Company is seeking recovery for $9.8 million in the VMWare License
17 Renewal project for the historical spend in 2025, as shown on line 16 of Exhibit A-
18 12, Schedule B5.7.7.
19
20 VMware is a virtualization and cloud computing software for IT infrastructure like
21 VRealize operations, VRealize automation, VMWare Hypervisor and vCenter
22 Server and vSphere Client, which the Company uses to run critical applications,
23 such as AMI, Maximo, and SAP. The software licensing reached expiration in 2025

Line No.

1 and renewal of the licenses was required to ensure that the Company's critical
2 infrastructure and applications remain operational.
3
4 The Company reports a variance of $4.7 million more over 24 months ending
5 December 31, 2026 than that approved for recovery per Case No. U-21860 Final
6 Order. The original plan assumed a three-year contract renewal. Following receipt
7 of the initial quote, the vendor increased the contract pricing, which prompted the
8 Company to negotiate and execute a five-year agreement. The five-year licensing
9 period increased the total contract cost compared to a three-year licensing period,
10 resulting in the reported variance, while providing longer-term contract stability.
11 See Exhibit A-24, Schedule N3 Revised, Line 77 for additional project details.
12
13 c) Return-to-Health
14 **Q69. What are the Infrastructure Operations Sub-Portfolio investment in the**
15 **Return-to-Health category?**
16 A69. The Company is seeking recovery for $34.0 million in the Return-to-Health
17 category of the Infrastructure Operations Sub-Portfolio over the 26 months ending
18 February 29, 2028, and the historical spend of $14.2 million over 12 months ending
19 December 31, 2025, as shown in lines 18 to 35 of the Capital Expenditures Exhibit
20 A-12, Schedule B5.7.7. These investments are described below.
21
22 (1) Conference Room Audio Video Support
23 The Company is seeking recovery for $0.5 million in the Conference Room Audio
24 Video Support project over the 26 months ending February 29, 2028, and the

Line No.

1 historical spend of $0.3 million in 2025, as shown on line 18 of Exhibit A-12,
2 Schedule B5.7.7.
3
4 The Conference Room Audio Video Support project in an annual investment that
5 will continue in 2027 and 2028. This project aims to offer technical expertise and
6 the hardware necessary for maintaining equipment in the Company's conference
7 rooms to ensure effective collaboration capabilities.

8 The Company reports a variance of $0.4 million less over 24 months ending
9 December 31, 2026 than that approved for recovery per Case No. U-21860 Final
10 Order. This variance reflects a reduction in project scope, as work in 2025 was
11 limited to updates for 10 conference rooms, resulting in lower expenditures than
12 originally forecast. See Exhibit A-24, Schedule N3 Revised, Lines 78-81 for
13 additional project details.
14
15 (2) Data Center Modernization and Optimization
16 The Company is seeking recovery for $1.6 million in the Data Center
17 Modernization and Optimization project over the 26 months ending February 29,
18 2028, and the historical spend of $0.7 million in 2025, as shown on line 19 of
19 Exhibit A-12, Schedule B5.7.7.
20
21 The Data Center Modernization and Optimization project is an annual investment
22 that will continue in 2027 and 2028. Data Center Modernization centers on
23 corporate application servers, storage and core communications, and the
24 distribution layer of services. Data Center Modernization focuses on the

Line No.

1 Company's central computing centers: the Detroit Data Center (DDC), Ann Arbor
2 Data Center (ADC), Electrical Systems Operations Center (ESOC) and Alternate
3 Systems Operations Center (ASOC). Four Uninterruptible Power Supplies (UPS)
4 in core data centers have exceeded their 20-year service life; this project will
5 replace them and the associated batteries to ensure power redundancy during
6 outages. UPS units are crucial for providing emergency backup power until
7 generators kick in, safeguarding critical IT equipment. Replacing the UPSs ensures
8 reliable power during outages, maintaining business operations. The batteries are
9 over five years old and will be upgraded to a newer technology that doubles their
10 lifespan and reduces annual maintenance by 50%. Delaying the replacement of
11 these end-of-life assets would increase the risk of loss of redundant power to the
12 infrastructure assets that the Company uses to host its business applications and
13 customer data. See Exhibit A-24, Schedule N3 Revised, Lines 82-84 for additional
14 project details.
15
16 (3) Digital Worker Experience Electric EOL
17 The Company is seeking recovery for $5.7 million in Digital Worker Experience
18 Electric EOL over the 26 months ending February 29, 2028, and the historical spend
19 of $3.6 million in 2025, as shown on line 34 of Exhibit A-12, Schedule B5.7.7.
20
21 The Digital Worker Experience EOL is an annual investment to replace end-of-life
22 endpoint devices like Laptops and Desktops to maintain the interfacing
23 connectivity to DTE business systems, communications, and data. The primary
24 interface devices used by the employees of DTE to access business systems,
25 communications and data are on Laptops, desktops, tablets, and smart devices.

Line No.

1 These devices become degraded after 5 years of service due to the age and versions
2 of the internal components such as (mother boards, storage & wireless
3 components). Refer to Table 3 below, Endpoint Device Replaced by Year.
4
5 Table 3 Device Type and Count Breakdown

Device Type	Refresh Year				
	2025 Planned	2025 Actual	2026	2027	2028
Laptop	676	812	400	400	400
Desktop	114	240	100	100	100
Monitors	63	213	100	100	100
Plotters, MacBooks, iPads		92			

6
7 The Company reports a variance of $2.0 million more over 24 months ending
8 December 31, 2026 than that approved for recovery per Case No. U-21860 Final
9 Order. This variance reflects the procurement of additional devices in 2025 and
10 2026 beyond the levels originally planned, as shown in Table 3, including laptops,
11 desktops, monitors, and other endpoint devices. See Exhibit A-24, Schedule N3
12 Revised, Lines 85-88 for additional project details.
13
14 (4) End of Life Replacement of Network Equipment supporting
15 Field Communications
16 The Company is seeking recovery for $2.4 million in End of Life (EOL)
17 Replacement of Network Equipment supporting Field Communications over the 26
18 months ending February 29, 2028, as shown on line 20 of Exhibit A-12, Schedule
19 B5.7.7.

Line No.

1

2 Network assets supporting Field Communications a.k.a. Operational Technology
3 Network Services have a definite End of Life (EOL). Without replacement, these
4 assets will become unviable and unreliable, which could result in unplanned
5 disruptions to critical business operations, and/or become vulnerable to potential IT
6 Security concerns and may provide a logical ingress point for bad actors (hackers).
7 This project aims to secure an investment to replace approximately 350 EOL
8 switches supporting field communications between 2027 and 2028. See Exhibit A-
9 24, Schedule N3 Revised, Lines 89-90 for additional project details.

10

11 (5) Endpoint Operating System and Hardware Upgrade

12 The Company is seeking recovery for $5.7 million in the Endpoint Operating
13 System (OS) and Hardware Upgrade project over the 26 months ending February
14 29, 2028, and has a historical spend of $1.7 million in 2025, as shown on line 21 of
15 Exhibit A-12, Schedule B5.7.7.

16

17 The Company's endpoint devices that have operating systems on antiquated
18 technology which will no longer be supported through Microsoft's standard support
19 process. This will prevent the user from being able to perform their job
20 responsibilities. Updating endpoint operating systems to Windows 11 will reduce
21 the Company's exposure to operating-system-based vulnerabilities within the
22 Company's network.

23

24 The Company reports a variance of $5.6 million less over 24 months ending
25 December 31, 2026 than that approved for recovery per Case No. U-21860 Final

Line No.

1 Order. This variance reflects a schedule adjustment of the project scope, as the
2 project was originally planned for completion in 2027. This is due to a strategic
3 funding reallocation toward higher priority initiatives across multiple portfolios to
4 support organizational needs. Table 4 below provides a breakdown of the planned
5 project scope for the 2025–2028 period.
6
7 Table 4 Endpoint OS and Hardware Upgrade 2025–2028

Category	Scope	2025 (completed to date)	2026–2028 (planned)
Devices upgraded	OS upgraded	4,349	-
Windows 10 incompatible	Replace device	-	4,252
Windows 11 incompatible	Replace device	-	1,200
OS upgrade required	Upgrade OS	-	2,300

8
9 See Exhibit A-24, Schedule N3 Revised, Lines 91-94 for additional project details.
10
11 (6) Field Worker Device End of Life
12 The Company is seeking recovery for $3.2 million in the Field Worker Device End
13 of Life project over the 26 months ending February 29, 2028, and has a historical
14 spend of $0.4 million in 2025, as shown on line 22 of Exhibit A-12, Schedule
15 B5.7.7.
16
17 This annual investment will establish and execute the annual EOL replacement
18 cycle for the enterprise Mobile Data Terminal (MDT) devices. MDT is a
19 computerized device used on mobile devices (devices in transit or devices that are
20 mounted on systems that are always on the move) to communicate with a

Line No.

1 centralized control system. Mobile data terminals are equipped with technology to
2 provide maps and information systems regarding geographic locations and other
3 information relevant to the tasks and actions performed by the devices they are
4 mounted on. These capabilities allow field workers to resolve customer issues
5 efficiently and provide input to customer service representatives so they may
6 effectively respond to customer queries. The lifecycle of the current MDT fleet has
7 been stretched to the point that field crew are experiencing multiple device and
8 connectivity failures. This impacts the crew's ability to gain insight into customer
9 issues and outages, provide updates to leadership and customer service, and
10 communicate resolution and closure of customer concerns in a safe and efficient
11 way.
12
13 Table 5 Field Worker Device Replacement Forecast by year

Device Type	2026	2027	2028
Mobile Data Terminals w/ docks	100	100	100

14
15 The Company reports a variance of $0.5 million less over 24 months ending
16 December 31, 2026 than that approved for recovery per Case No. U-21860 Final
17 Order. This is due to a strategic funding reallocation toward higher-value initiatives
18 across multiple portfolios. See Exhibit A-24, Schedule N3 Revised, Lines 95-98 for
19 additional project details.
20
21 (7) IT Infrastructure EOL Asset Replacement
22 The Company is seeking recovery for $1.7 million in the IT Infrastructure EOL
23 Asset Replacement project (previously known as End-of-life Asset Replacements)

Line No.

over the 26 months ending February 29, 2028, and the historical spend of $0.6 million in 2025, as shown on line 23 of Exhibit A-12, Schedule B5.7.7.

The EOL Asset Replacement is an annual investment that supports replacement of servers, storage, databases, and operating licenses that are at end of their serviceable life, which means they are no longer capable of accepting operating system or security vulnerability remediation, capacity has reached the upper threshold of processing ability, or the technology will no longer interact with newer components within the architecture. These assets located within the Company's corporate data centers or major secondary sites rely on continuous upgrades to ensure that security, capacity, and operating parameters can meet business requirements (see Table 6 below).

Table 6 Device Lifecycle Management Standards

Component	Lifecycle
Servers	5 Years
Storage	3 Years
Operating Systems	Annual Upgrades
Databases	Annual Upgrades

The Company reports a $0.23 million more over 24 months ending December 31, 2026 than that approved for recovery per Case No. U-21860 Final Order.. The additional spend is required to complete the end-of-life (EOL) assets within the scope, specifically the Maestro Upgrade and the HPOM Replacement with Dynatrace which required design changes and external consulting support,

Line No.

1 resulting in higher-than-planned costs. See Exhibit A-24, Schedule N3 Revised,
2 Lines 99-102 for additional project details.
3
4 (8) Network EOL Support – SOC Operations
5 The Company is seeking recovery for $0.5 million in the Network EOL Support –
6 SOC Operations project over the 26 months ending February 29, 2028 as shown on
7 line 26 of Exhibit A-12, Schedule B5.7.7.
8
9 This project is to replace End of Life network hardware that supports SOC
10 operations and associated application portfolio including EMS, GMS and ADMS
11 in 2027 and 2028. These updated solutions will address the components that have
12 reached their end of designed and serviceable life, as well as provide additional
13 network expansions to meet business-partner requirements, expectations, and
14 demand. The Company has 18 switches that have been serving us for over 7 years
15 and will reach end of life later in 2026. These switches need to be replaced to
16 provide reliable and secure Network services to SOC operations and associated
17 application portfolio. See Exhibit A-24, Schedule N3 Revised, Lines 106-107 for
18 additional project details.
19
20 (9) Network Security End of Life Asset Replacement
21 The Company is seeking recovery for $1.2 million in the Network Security End of
22 Life Asset Replacement project over the 26 months ending February 29, 2028 as
23 shown on line 27 of Exhibit A-12, Schedule B5.7.7.

Line No.

1 The Company's network security infrastructure includes a significant number of
2 components that will reach end of life (EOL) over the 2027–2028 period.
3 Components that exceed their EOL dates lose vendor support and become
4 non-serviceable, increasing the risk of security vulnerabilities and impacts to
5 network availability. This investment supports the timely replacement of EOL
6 network security hardware to ensure continued vendor support and to avoid
7 operating beyond supported lifecycles. The assets in scope provide critical security
8 and connectivity services across the Company, including web access for business
9 units; secure operation of customer-facing systems such as payment platforms;
10 protection of electric and gas field communications, including SCADA and
11 metering networks; secure operation of energy supply plant control systems; and
12 protected information exchange with financial, regulatory, and employee-benefits
13 partners. See Exhibit A-24, Schedule N3 Revised, Lines 108-109 for additional
14 project details.
15
16 (10) Network UPS End of Life Replacement and Business Continuity
17 The Company is seeking recovery for $0.7 million in the Network UPS End of Life
18 Replacement and Business Continuity project over the 26 months ending February
19 29, 2028, as shown on line 28 of Exhibit A-12, Schedule B5.7.7.
20
21 The Company's network Uninterruptible Power Supply (UPS) units are aging, and
22 battery replacements are required more frequently. Unexpected UPS failures can
23 result in outages in telecom closets, disrupting the operation of network equipment
24 that supports end-user connectivity at the access layer for workstations and laptops.
25 This investment supports collaboration with a third-party vendor to deploy and

Line No.

1 manage UPS solutions that provide reliable network connectivity for the
2 Company's end users. The scope includes monitoring, maintenance, repairs, and
3 deployment of UPS units over a three-year period, with replacements aligned to the
4 Company's established end-of-life criteria. The Company reports a variance of $0.1
5 million more over 24 months ending December 31, 2026 than that approved for
6 recovery per Case No. U-21860 Final Order, primarily due to the 20% disallowance
7 in 2026. See Exhibit A-24, Schedule N3 Revised, Lines 110-112 for additional
8 project details.
9
10 (11) Replace Data Center End of Life Network Infrastructure
11 The Company is seeking recovery for $1.0 million in the Replace Data Center End
12 of Life Network Infrastructure previously called Network Data Center End of Life
13 Project over the 26 months ending February 29, 2028, and the historical spend of
14 $0.4 million in 2025, as shown on line 29 of Exhibit A-12, Schedule B5.7.7.
15
16 This annual investment is required to replace data-center core switches, routers, and
17 install new components to allow the Company to increase the connection bandwidth
18 between its two data centers. Business applications with a requirement of failover
19 and backup capabilities rely on the operability of these devices to ensure continuity
20 in the event of an unplanned outage. See Exhibit A-24, Schedule N3 Revised, Lines
21 113-116 for additional project details.
22
23 (12) Replace End of Life Microwave Infrastructure
24 The Company is seeking recovery for $0.9 million in the Replace End of Life
25 Microwave Infrastructure previously known as Microwave End of Life project over

Line No.

1 the 26 months ending February 29, 2028, and the historical spend of $0.4 million
2 in 2025, as shown on line 30 of Exhibit A-12, B5.7.7.
3
4 This investment supports the Company's microwave communications
5 infrastructure, which the Company owns and operates to provide reliable
6 transmission of data, voice, and video across DTE facilities. The project supports
7 hardware upgrades and configuration changes necessary to sustain higher network
8 speeds and improve overall system performance. This annual investment includes
9 replacement of microwave paths, enhancements to stabilize the microwave ring,
10 and updates required to comply with Federal Communications Commission (FCC)
11 changes related to deregulation of the 6-gigahertz (GHz) frequency band. These
12 efforts improve infrastructure redundancy, availability, and security. See Exhibit
13 A-24, Schedule N3 Revised, Lines 117-120 for additional project details.
14
15 (13) Replace End of Life Network Infrastructure
16 The Company is seeking recovery of $1.5 million for the Replace End of Life
17 Network Infrastructure previously called Network End of Life Electric (project
18 over the 26-month period ending February 29, 2028, and recovery of $0.7 million
19 of historical expenditures incurred in 2025, as shown on line 35 of Exhibit A-12,
20 Schedule B5.7.7.
21
22 The Network End of Life Electric project is an ongoing investment to replace EOL
23 network hardware that is not physically located in either of the corporate data
24 centers. These updated solutions will address the components that have reached
25 their end of designed and serviceable life and provide additional network

Line No.

expansions to meet business partner requirements, expectations, and demand. (see Table 7).

Table 7 Network Devices Replaced by Year

Year	2025	2026	2027	2028
Assets Replaced	34	44	40	60

The Network EOL – Electric project will annually fund only those devices within the purview of Infrastructure and Operations. This investment will maintain the core foundation for investments like Time of Use billing, and accounts for planned data loads as new electric-grid-control systems come online. It will further increase the size and capacity of existing equipment as key electrical-control points for required security upgrades. Examples of these enhancements are support for perimeter intrusion detection and streaming real-time video surveillance at locations that are deemed critical or high. This updated infrastructure will provide improved stability and supportability across the network. See Exhibit A-24, Schedule N3 Revised Line 121-124 for additional project details.

(14) Security Infrastructure Growth and EOL

The Company is seeking recovery for $3.0 million in the Security Infrastructure Growth and EOL project over the 26 months ending February 29, 2028, and the historical spend of $2.0 million in 2025, as shown on line 31 of Exhibit A-12, Schedule B5.7.7.

Security Infrastructure Growth and EOL is an ongoing investment that will continue through 2027 and 2028. This project targets the annual replacement of

Line No.

1 approximately 15% to 20% of security infrastructure equipment to maintain system
2 reliability and supportability. This includes all upgrades, Return Merchant
3 Authorizations, configuration changes, firewalls, Domain Name System, Global
4 Protect, Certificate management etc. These systems have an average life span of
5 five to seven years, consistent with original equipment manufacturer (OEM)
6 recommendations. The Security Infrastructure End of Life project covers a much
7 broader suite of activities to support Network Security annual sustainment. As
8 reflected in Table 8 below, the equipment follows the replacement cycles shown to
9 ensure it remains within the vendor's supportable life.
10
11 Table 8 Security Asset Lifecycle

Asset	Lifecyle
System Baselining	4 years
Firewalls	5 years
Domain Name System (DNS)	6/7 years
Vulnerability Tool	6 years
Web Proxy	5 years
DataPower	4 years
Windows server hardware/software	5-7 years

12
13 The Company reports a variance of $0.75 million more over 24 months ending
14 December 31, 2026 than that approved for recovery per Case No. U-21860 Final
15 Order. Of this amount, $0.15 million is due to the 10% disallowance applied in
16 2025 per final order U-21860. The remaining $0.6 million reflects the replacement
17 of SOC and ESOC firewalls required to address capacity constraints identified in
18 2025. See Exhibit A-24, Schedule N3 Revised, Lines 125-128 for additional project
19 details.

Line No.

1 (15) Virtual Desktop Infrastructure Asset Health

2 The Company is seeking recovery for $1.8 million in the Virtual Desktop
3 Infrastructure Asset Health project over the 26 months ending February 29, 2028,
4 and has a historical spend of $1.5 million in 2025, as shown in line 32 of Exhibit
5 A-12, Schedule B5.7.7.
6
7 This investment supports the Company's continued migration of its virtual desktop
8 and application infrastructure from a Citrix-based environment to a hybrid Azure
9 solution utilizing Azure Virtual Desktop (AVD). The Company is replacing Citrix
10 assets with Azure-based capabilities as existing Citrix components reach end of life
11 (EOL), maximizing the value of current investments while aligning with the
12 Company's cloud strategy. This effort represents a continuation of work initiated
13 in 2024 and, by 2026, more than 50% of the Citrix environment will be migrated to
14 Azure. 2027 and 2028 investment supports incremental growth and represents the
15 final phase of removing Citrix from the Company's environment. Completion of
16 this phase is necessary to maintain reliable virtual access and application delivery
17 for approximately 7,000 users across the enterprise.
18
19 The Company reports a variance of $1.1 million more over 24 months ending
20 December 31, 2026 than that approved for recovery per Case No. U-21860 Final
21 Order. Of this amount, $0.2 million is due to the 10% and 20% disallowances
22 applied in 2025 and 2026 by the Commission. The remaining $0.9 million is due to
23 the purchase of an additional 529 virtual desktops in 2025 to support enterprise
24 needs. See Exhibit A-24, Schedule N3 Revised, Lines 129-132 for additional
25 project details.

Line No.

1 (16) Wide Area Network and Wireless Local Area Network
2 Expansion

3 The Company seeks recovery of $2.2 million for the Wide Area Network (WAN)
4 and Wireless Local Area Network (WLAN) Expansion project over the 26-month
5 period ending February 29, 2028, and has historical expenditure of $1.0 million in
6 2025, as shown on line 33 of Exhibit A-12, Schedule B5.7.7.
7
8 This investment supports the upgrade of the Company's WAN and core telephony
9 infrastructure and the expansion of WLAN capabilities to meet enterprise needs.
10 The scope includes telephony platform replacement with Microsoft Teams
11 integration and E911 support, WLAN expansion to additional locations, data-center
12 WiFi controller implementation, and access point replacements at the Detroit
13 headquarters, improving reliability, redundancy, and readiness for future growth.
14 See Exhibit A-24, Schedule N3 Revised, Lines 133-136 for additional project
15 details.
16
17 d) IT Enhancements
18 **Q70. What is the Infrastructure Operations Sub-Portfolio investment in the IT**
19 **Enhancements category?**
20 A70. The Company is seeking recovery for a historical spend of $0.3 million in 2025, in
21 the IT Enhancement category of the Infrastructure Operations Sub-Portfolio as
22 shown in line 36 of the Capital Expenditures – Exhibit A-12, Schedule B5.7.7. The
23 investment is described below.

Line No.

1 (1) Network Segmentation (phase 2+) emergent extension

2 The Company is seeking recovery for the historical expenditure of $0.3 million in
3 the Network Segmentation (phase 2+) emergent extension in 2025 as shown on line
4 36 of Exhibit A-12, Schedule B5.7.7.
5
6 The Network Segmentation (phase 2+) emergent extension project will continue in
7 2026. Cyber threats continue to rise, and it has become increasingly important to
8 add additional cybersecurity countermeasures to the Company's networks. Legacy
9 network switches must be replaced due to incompatibility with the new N9K-FX3
10 network switches. This incompatibility prevents the configuration of the Cisco
11 Application Centric Infrastructure (ACI) technology that restricts traversing the
12 DTE network. This has impacted the installation and use of firewalls to isolate
13 applications running on obsolete operating systems. This project will support
14 installation and configuration of a combination of Cisco N9X3 network switch
15 based ACI technology and firewalls to isolate applications from intrusion.
16 Separation of critical applications and data from general infrastructure is necessary
17 to mitigate the risk of cybersecurity incidents.
18
19 The Company reports a variance of $0.4 million over 24 months ending December
20 31, 2026 than that approved for recovery per Case No. U-21860 Final Order, due
21 to reprioritization of higher-priority organizational needs beginning in 2026. See
22 Exhibit A-24, Schedule N3 Revised, Line 137 for additional project details.

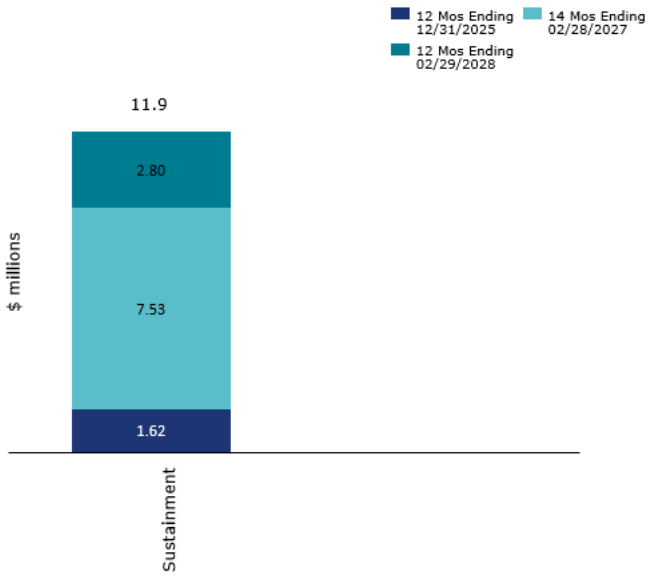
Line No.

4. Enterprise Data & Digital Platform

Q71. What are the projected costs for investments in the Enterprise Data & Digital Platform Sub-Portfolio?

A71. As reflected on line 8 of Exhibit A-12, Schedule B5.7, page 1, capital expenditures for Enterprise Data & Digital Platform total $1.6 million for the historical test year ended December 31, 2025, $7.5 million in the bridge period (for the 14 months ending February 28, 2027), and $2.8 million for the projected test period ending February 29, 2028. The synopsis below generally provides the total spend for each line item the Company requests in this rate case and the details regarding breakout by historical period, projected bridge period, and projected test period, are laid out in Exhibit A-12, Schedule B5.7.8, in columns d, g, and h. Figure 9 below represents a high-level view of capital allocation within the Sub-Portfolio.

Figure 9 Enterprise Data & Digital Platform – IT Investment



Line No.

a) Sustainment

Q72. What is the Enterprise Data & Digital Platform Sub-Portfolio investment in the Sustainment category?

A72. The Company is seeking recovery for $10.3 million in the Sustainment Category of the Enterprise Data Analytics Sub-Portfolio over the 26 months ending February 29, 2028, and the historical spend of $1.6 million in 2025, as shown on line 1 - 3 of the Capital Expenditures Exhibit A-12, Schedule B5.7.8. These investments are described below.

(1) Digital Platform Application Health

The Company is seeking recovery for $4.5 million into the Digital Platform Application Health project over the 26 months ending February 29, 2028, as shown on line 1 of Exhibit A-12, Schedule B5.7.8.

The Digital Platform Application Health investment supports the ongoing operation, stability, and reliability of foundational digital platform applications. This investment supports maintaining the core Enterprise Data Platform and Digital Platform applications that enable analytics, reusable digital components, and common services relied upon by multiple business applications across the Company. This investment ensures the continued availability, security, and performance of the underlying platforms and foundational services that support digital products and enterprise capabilities. The do-nothing alternative was evaluated and rejected, as proactive maintenance and management of these foundational components are necessary to mitigate operational and cybersecurity risk and to ensure that dependent applications can continue to function reliably

Line No.

during normal operations and critical events, including storm response, crew coordination, and time reporting. See Exhibit A-24, Schedule N3 Revised, Lines 139- 141 for additional project details.

B. Corporate Applications

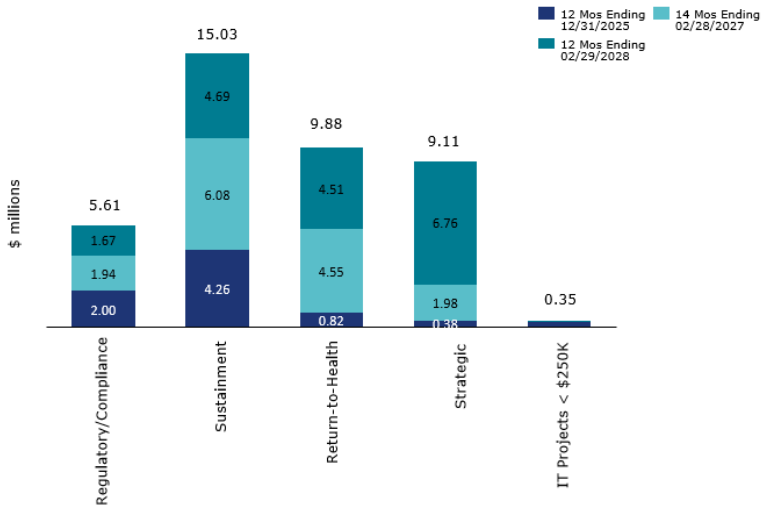
Q73. What are the projected costs for investments in the Corporate Applications Portfolio?

A73. As reflected on Line 2 of Exhibit A-12, Schedule B5.7, page 1, capital expenditures for Corporate Applications total $7.7 million for the historical year ended December 31, 2025, $14.6 million in the projected 14-month bridge period ending February 28, 2027, and $17.7 million for the projected test period ending February 29, 2028.

The synopses below provides the total spend for each line item the Company requests in the instant case, and the cost details for projects in this Portfolio broken out by historical period, projected bridge period, and projected test period, are provided in Exhibit A-12, Schedule B5.7.1, in columns (d), (g) and (h), respectively. Figure 10 represents a high-level view of capital allocation within the Portfolio.

Line No.

Figure 10 Corporate Applications – IT Investment



a) Regulatory/Compliance

Q74. What are the Corporate Applications investments in the Regulatory/Compliance category?

A74. The Corporate Applications Portfolio is seeking recovery for $3.6 million in the Regulatory/Compliance category over the 26 months ending February 29, 2028 and the historical spend of $2.0 million over the 12 months ending in December 2025, as shown in lines 1 and 2 of the Capital Expenditures - Exhibit A-12, Schedule B5.7.1. These investments are described below.

(1) Core ERP Stacks and Packs

The Company is seeking recovery for $3.6 million in the Core ERP Stacks and Packs project over the 26 months ending February 29, 2028, and the historical spend of $1.6 million in 2025, as shown on line 1 of Exhibit A-12, Schedule B5.7.1.

Line No.

1 The Core ERP Stacks and Packs project is a recurring annual investment to ensure
2 that the SAP ERP system is up to date with the latest required support packs and
3 stacks. The Company's Core Enterprise Resource Planning (ERP) platform – the
4 SAP ERP system – supports all resource planning processes and systems for the
5 Corporate Services, Human Resources (HR), and Finance Organizations. Examples
6 of critical processes that SAP supports are Financial Close, Financial Asset
7 Management, Financial Reporting, Time Management, Payroll Processing,
8 Purchasing, and Tax Management. There are also critical integrations that support
9 Customer Billing and Asset and Work Management. The SAP ERP system requires
10 regular support pack patching to ensure that it remains updated with the necessary
11 software and platform support to comply with legal and regulatory requirements
12 for payroll, benefits, and HR reporting, meet corporate reporting mandates, and
13 minimize outages by aligning all required patching within the same outage window.
14 See Exhibit A-24, Schedule N3 Revised, Lines 145 - 148 for additional project
15 details.
16
17 (2) Secure 2.0 Act for 401K
18 The Company is seeking recovery for a historical spend of $0.4 million in Secure
19 2.0 Act for 401K project in 2025, as shown on line 2 of Exhibit A-12, Schedule
20 B5.7.1.
21
22 SECURE 2.0 Act – Section 603 requires that catch-up contributions to qualified
23 retirement plans be treated as Roth contributions for employees with compensation
24 greater than $145,000, effective for taxable years beginning after December 31,
25 2023. This investment supports the system changes necessary for the Company to

Line No.

1 comply with this statutory requirement and ensure accurate tax treatment of
2 employee retirement contributions. In addition, this investment supports updates to
3 the 401(k) catch-up election design to simplify plan administration and ensure
4 consistent processing of tax rollovers. The scope includes enabling rollover of
5 post-tax benefit deductions to other post-tax deductions and automatically rolling
6 an employee's Roth post-tax contributions into a 401(k) Roth rollover once
7 contribution limits are reached. These changes ensure regulatory compliance,
8 improve operational efficiency, and maintain accurate and reliable administration
9 of the Company's retirement plans. See Exhibit A-24, Schedule N3 Revised, Line
10 149 for additional project details.
11
12 b) Sustainment
13 **Q75. What are the Corporate Applications investments in the Sustainment**
14 **category?**
15 A75. The Corporate Applications Portfolio is seeking recovery for $10.8 million in the
16 Sustainment category over the 26 months ending February 29, 2028, and the
17 historical spend of $4.3 million in 2025, as shown in line 3 through line 9 of the
18 Capital Expenditures - Exhibit A-12, Schedule B5.7.1. These investments are
19 described below.
20
21 (1) Corporate Services Application Health
22 The Company seeks recovery of $1.8 million for the Corporate Service Application
23 Health project over the 26-month period ending February 29, 2028, plus $0.6
24 million of historical 2025 expenditures, as shown on line 3 of Exhibit A-12,
25 Schedule B5.7.1.

Line No.

1 This ongoing annual investment upgrades and ensures the health, reliability, and
2 security of 40 applications in the Corporate Applications Portfolio running on
3 unsupported infrastructure and operating systems. These applications such as Safe
4 Worker Observations, fleet and fuel management, and emissions monitoring
5 support critical functions across Supply Chain, Environmental Management, and
6 Corporate Safety organizations. The project delivers software, hardware, and
7 database patches; version upgrades for regulatory changes; security vulnerability
8 resolutions; and vendor software updates to prevent outages, business disruptions,
9 system failures, and cyber threats while maintaining vendor support and
10 compliance. See Exhibit A-24, Schedule N3 Revised, Line 150 - 153 for additional
11 project details.
12
13 (2) Documentum (EDM) Application Health
14 The Company is seeking recovery for $1.8 million in the Documentum (Enterprise
15 Document Management) Application Health project over the 26 months ending
16 February 29, 2028, and the historical spend of $0.4 million in 2025, as shown in
17 line 4 of the Capital Expenditures - Exhibit A-12, Schedule B5.7.1
18
19 The Documentum Application Health project is an annual investment that is
20 required to maintain the Documentum platform. Documentum is a supported
21 interface to work management system and serves as an electronic repository which
22 connects with the Company's work management system, providing user access to
23 documents while executing work orders. The investment ensures that the
24 Documentum platform remains secure and available to meet document repository
25 objectives in support of DTE's defined document management strategy and covers

Line No.

implementation support for security vulnerability remediation, system upgrades, and system growth (sizing). See Exhibit A-24, Schedule N3 Revised, Lines 154 - 157 for additional project details.

(3) Enterprise Applications Health

The Company is seeking recovery for $1.8 million in the Enterprise Applications Health project over the 26 months ending February 29, 2028, and the historical spend of $0.7 million in 2025, as shown on line 5 of Exhibit A-12, Schedule B5.7.1.

The Enterprise Applications Health project is an annual investment that encompasses maintenance of 19 critical applications, including Primavera, Captiva, Maxavera, and RightFax, that are integral to supporting DTE's Finance, Legal, and Major Enterprise Projects Organizations. This investment prioritizes keeping these applications updated and security-patched. The benefits of this project are safeguarding these applications against outages or disruptions that might arise from IT component failures, security vulnerabilities, or incompatibility with newer technologies, ensuring strict adherence to regulatory requirements such as those mandated by NERC, and maintaining appropriate vendor support. Over the next few years, this project will focus on upgrading the PACS OnGuard system and ensure the completion of monthly patches. See Exhibit A-24, Schedule N3 Revised, Lines 158-161 for additional project details.

(4) Enterprise Resource Planning (ERP)

The Company is seeking recovery for $2.2 million in the Enterprise Resource Planning (ERP) project over the 26 months ending February 29, 2028, and the

Line No.

1 historical spend of $1.4 million in 2025, as shown on line 6 of Exhibit A-12,
2 Schedule B5.7.1.
3
4 The Enterprise Resource Planning (ERP) system is a core platform that supports all
5 resource planning processes and systems that are also supported through the SAP
6 platform for Corporate Services, Human Resources, and Finance Organizations.
7 This investment maintains the ERP system through monthly releases to upgrade
8 end-of-life components, essential critical failover testing to support SOX
9 compliance, and timely responses to evolving legal, tax, and safety requirements.
10 See Exhibit A-24, Schedule N3 Revised, Lines 162 - 165 for additional project
11 details.
12
13 (5) Financial Applications Health
14 The Company is seeking recovery for $1.7 million in the Financial Applications
15 Health project over the 26 months ending February 29, 2028, and the historical
16 spend of $0.3 million in 2025, as shown on line 7 of Exhibit A-12, Schedule B5.7.1.
17
18 The Financial Applications Health project is an annual investment that supports the
19 reliability, security, and vendor support of 18 critical financial applications,
20 including PowerPlan, OneSource, BPC, Concur, and Cadency. In 2025, the
21 Company ensured Windows 11 compatibility across all applications, implemented
22 updates to the Oracle Financial Planning Tool, and resolved a security vulnerability
23 in the Investor Relations website.
24

Line No.

1 The Company reports a variance of $0.4 million more over 24 months ending
2 December 31, 2026 than that approved for recovery per Case No. U-21860 Final
3 Order. Of this amount, $0.2 million is due to the 10% disallowance applied in 2025
4 and 2026 as per final order U-21860. The remaining $0.2 million is due to
5 PowerPlan uplift charges and application support costs incurred in 2026 to support
6 successful execution of the project. See Exhibit A-24, Schedule N3 Revised, Lines
7 166-169 for additional project details.
8
9 (6) Human Resources Health Applications
10 The Company is seeking recovery for $0.7 million in the Human Resources
11 Applications Health project over the 26 months ending February 29, 2028, and the
12 historical spend of $0.3 million in 2025, as shown on line 8 of Exhibit A-12,
13 Schedule B5.7.1.
14
15 The Human Resources Applications Health project is an annual investment that
16 ensures the health and stability of Human Resources (HR) applications, including
17 SuccessFactors Platform, OpenText, and Oracle backends, by conducting required
18 upgrades to these applications to ensure they are running on supported
19 infrastructure and replacing operating systems as needed. These upgrades ensure
20 that each application is current and operating with the latest functions and features
21 to support business processes. This project also supports the application
22 configuration changes that are built, tested, and deployed through monthly change
23 release to support Human Resources business process requirements.
24

Line No.

1 The Company reports a variance of $0.2 million more over 24 months ending
2 December 31, 2026 than that approved for recovery per Case No. U-21860 Final
3 Order. Of this amount, $0.05 million is due to the 10% disallowance applied in
4 2025 and 2026 as per final order U-21860. The remaining $0.15 million is due to
5 required enhancements to support Everbridge application administration, resulting
6 in higher costs during the period. See Exhibit A-24, Schedule N3 Revised, Lines
7 170-173 for additional project details.
8
9 (7) Production Growth
10 The Company is seeking recovery for $0.8 million in the Production Growth project
11 over the over the 26 months ending February 29, 2028, and the historical spend of
12 $0.5 million in 2025, as shown on line 9 of Exhibit A-12, Schedule B5.7.1.
13
14 The Production Growth project is an annual investment that enables the continuous
15 expansion of DTE's computing environment in response to increasing demand on
16 the Company's on-premise Corporate Application systems. The project covers
17 infrastructure assets for computing power, storage capacity, database availability
18 and middle tier infrastructure.
19
20 The Company reports a variance of $0.8 million less over 24 months ending
21 December 31, 2026 than that approved for recovery per Case No. U-21860 Final
22 Order. In 2025, a portion of the planned SAP system growth scope did not proceed
23 following implementation of data archiving, which reduced near-term capacity
24 requirements and resulted in an underspend during the year. In 2026, the remaining
25 scope was reprioritized, resulting in deferral of this work to 2027 and lower

Line No.

1 expenditures during the period. See Exhibit A-24, Schedule N3 Revised Lines 174-
2 177 for additional project details.
3
4 c) Return-to-Health
5 **Q76. What is the Corporate Applications Portfolio investment in the Return-to-**
6 **Health category?**
7 A76. The Corporate Applications Portfolio is seeking recovery for $9.1 million in the
8 Return-to-Health category over the 26 months ending February 29, 2028, and the
9 historical spend of $0.8 million in 2025, as shown on lines 10-14 of the Capital
10 Expenditures - Exhibit A-12, Schedule B5.7.1. These investments are described
11 below.
12
13 (1) Cloud Health and Safety
14 The Company is seeking recovery of $0.5 million for the Cloud Health and Safety
15 project over the 12-month historical period ending December 31, 2025 as shown
16 on line 10 of Exhibit A-12, Schedule B5.7.1.
17
18 DTE Energy's Corporate Safety processes require critical enhancements to its
19 information technology systems to support improved safety oversight and
20 regulatory compliance. The current environment is characterized by fragmented
21 platforms, manual reporting processes, and limited capabilities for trend analysis.
22 These deficiencies hinder the company's ability to proactively identify and mitigate
23 safety risks, delaying corrective actions and reducing the effectiveness of
24 enterprise-wide safety initiatives The Cloud Health and Safety Project address these
25 gaps by implementing a unified, cloud-based platform that streamlines safety data

Line No.

1 collection, reporting, and analysis. This investment will Improve operational
2 efficiency by consolidating disparate systems and eliminating duplicative
3 processes, enhance data accuracy and timeliness, enabling faster response to
4 incidents and near-misses.
5
6 The company reports a variance of $0.2 million more over 24 months ending
7 December 31, 2026 than that approved for recovery per Case No. U-21860 Final
8 Order. Of this amount, $0.03 million is due to 10% disallowance from commission
9 as noted in the U-21860 final order. The remaining variance is for additional
10 support required for completion of scope related to of Safe Worker Observation
11 (SWO), High Energy Control Assessment (HECA), Stop Work, etc. that was added
12 during implementation. See Exhibit A-24, Schedule N3 Revised, Line 178 for
13 additional project details.
14
15 (2) Compensation, Time Entry and Payroll Implementation
16 The Company is seeking recovery of $7.3 million for the Compensation, Time
17 Entry and Payroll Implementation project over the 26-month period ending
18 February 29, 2028, as shown on line 11 of Exhibit A-12, Schedule B5.7.1. This
19 multi-year project, beginning in 2026, modernizes the Company's payroll and
20 time-management capabilities through implementation of SAP Time Management
21 and SAP Employee Central Payroll, replacing the legacy SAP payroll system
22 implemented in 2007.
23
24 In Case No. U-21860, the Company sought recovery of $5.0 million for the
25 12-month period ending December 31, 2026, based on the project scope at that

Line No.

time, which included time entry and payroll functionality. As detailed planning progressed in 2026, the Company refined the project scope to incorporate compensation functionality and adjusted the implementation sequencing to support a more integrated and sustainable solution. As a result, originally planned scope for 2026 were re-sequenced to later years, and the Company reports a variance of $1.4 million less over 24 months ending December 31, 2026 than that approved for recovery per Case No. U-21860 Final Order. This variance is due to re-sequencing of project activities. The revised schedule allows the Company to manage implementation risk, better align resources, and support successful execution of the expanded scope over the full project duration ending December 31, 2029. See Exhibit A-24, Schedule N3 Revised, Lines 179-181 for additional project details.

(3) Environmental Air Regulation Management

The Company is seeking recovery for $0.2 million in the Environmental Air Regulation Management project over the over the 26 months ending February 29, 2028 and the historical spend of $0.3 million in 2025, as shown on line 12 of Exhibit A-12, Schedule B5.7.1.

The Company currently uses the Opsinfo application for regulatory air emissions reporting and voluntary environmental, social, and governance (ESG) reporting. As Opsinfo has transitioned to a cloud-based platform, the Company's existing on-premises version has become obsolete, non-upgradable, and exposed to security risk, requiring reliance on external resources to manually consolidate emissions data and prepare compliance reports. This project replaces the legacy Opsinfo system with the Sphera Cloud application to support future air and greenhouse gas

Line No.

1 emissions reporting, including MAERS, TRI, GHG, NSR, and air permit reporting.
2 Implementation of Sphera will address security concerns, ensure continued
3 compliance with regulatory and voluntary reporting requirements, and establish a
4 sustainable and reliable emissions reporting process. Based on design-phase
5 findings and vendor input, the Company determined that completing the full scope
6 in 2026 is necessary to ensure compliance, quality, and long-term sustainability of
7 the solution. See Exhibit A-24, Schedule N3 Revised, Lines 182-183 for additional
8 project details.
9
10 (4) PowerPlan PowerTax Upgrade
11 The Company is seeking recovery for $0.3 million in the PowerPlan Tax Upgrade
12 project over the over the 26 months ending February 29, 2028 as shown on line 13
13 of Exhibit A-12, Schedule B5.7.1.
14
15 The PowerTax application receives fixed-asset data from PowerPlan, enabling the
16 Company's tax department to perform compliant tax depreciation management,
17 including tax basis calculations, depreciation schedules, and gain/loss
18 determinations, in accordance with applicable IRS regulations and financial
19 reporting standards. The application ensures accurate application of complex tax
20 rules across the Company's regulated asset base.
21
22 The current version of PowerTax will reach end of life in December 2027, requiring
23 an upgrade to maintain regulatory compliance and operational reliability. Without
24 this upgrade, the Company's General Accounting and Reporting (GAAP) teams
25 would rely on an unsupported system, increasing financial reporting risk and the

Line No.

1 potential for non-compliance with GAAP requirements. The Company's expanding
2 infrastructure, including new data centers within the service territory, increases the
3 volume of assets requiring precise tax tracking and depreciation. Upgrading
4 PowerTax will support continued compliance with evolving IRS and regulatory
5 standards while maintaining reliable integration and scalability for the Company's
6 financial operations. See Exhibit A-24, Schedule N3 Revised, Line 184 for
7 additional project details.
8
9 (5) PowerPlan Upgrade
10 The Company is seeking recovery for $1.4 million in the PowerPlan Upgrade
11 project over the over the 26 months ending February 29, 2028 as shown on line 14
12 of Exhibit A-12, Schedule B5.7.1.
13
14 The PowerPlan Fixed Asset module is a critical system used by the Company to
15 manage the full lifecycle of regulated assets, including construction cost
16 accounting, asset classification, depreciation, and compliance with regulatory and
17 financial reporting requirements. The system integrates with the general ledger to
18 support accurate and timely financial reporting. The Company's existing
19 on-premises PowerPlan platform is no longer supported by the vendor, creating
20 material risk to continued compliance with regulatory accounting and depreciation
21 standards. Migration to the Software-as-a-Service (SaaS) version is necessary to
22 maintain vendor support, mitigate compliance risk, and support the Company's
23 expanding infrastructure, including new data centers serving the service territory.
24 See Exhibit A-24, Schedule N3 Revised, Line 185 for additional project details.

Line No.

d) Strategic

Q77. Please explain the Corporate Applications Portfolio investment in the Strategic category.

A77. The Company is seeking recovery for $8.7 million in the Strategic category of the Corporate Applications Portfolio over the 26 months ending February 29, 2028, and the historical spend of $0.4 million in 2025 as shown in lines 15 through 18 of the Capital Expenditures - Exhibit A-12, Schedule B5.7.1. These investments are described below.

(1) Real Estate Management

The Company is seeking recovery for $2.6 million for the Real Estate Management project over a 26-month period ending February 29, 2028, as shown on line 16 of Exhibit A-12, Schedule B5.7.1.

Through this project, DTE is launching the SAP Real Estate initiative to streamline property leasing, taxation, and legal boundary verification. Currently, access to legal documents such as lease contracts, easement drawings, and real estate transaction records is manual and time-consuming due to their storage across multiple repositories. The Real Estate Management project will implement the SAP Capital Lease Management (CLM) module and integrate it with the existing SAP Employee Central Component, Documentum, and the future SAP S/4HANA implementation. This integration will enhance productivity and support sustainable property portfolio management by eliminating manual, time-consuming tasks and providing Real Estate employees with a single repository for document access,

Line No.

1 thereby more effectively supporting Corporate Legal, Tax, Renewable, Gas, and
2 Electric Field personnel.
3
4 The Company reports a variance of $2.3 million less over 24 months ending
5 December 31, 2026 than that approved for recovery per Case No. U-21860 Final
6 Order, primarily due to a deferral of the Real Estate Management project to 2027.
7 See Exhibit A-24, Schedule N3 Revised, Line 187 for additional project details.
8
9 (2) Source-to-Pay Transformation
10 The Company is seeking recovery of $5.3 million for the Source-to-Pay
11 Modernization project over the 26-month period ending February 29, 2028, as
12 shown on line 17 of Exhibit A-12, Schedule B5.7.1.
13
14 The Company is committed to advancing long-term, sustainable energy initiatives
15 through the modernization of the electric grid and enhancements to natural gas
16 infrastructure. To support and scale these investments, Information Technology
17 Services (ITS) must modernize the Procure-to-Pay (P2P) process. The current P2P
18 framework lacks the agility, transparency, and efficiency necessary to support the
19 complex and high-volume procurement activities associated with energy
20 infrastructure projects. To address these challenges, the Company will implement
21 SAP Ariba as its enterprise source-to-pay solution. This modernization will provide
22 real-time visibility into procurement activities, supplier performance, and spend
23 management, supporting improved decision-making and compliance. The solution
24 will also enable integrated supplier collaboration and risk assessment capabilities
25 to strengthen supplier relationships and mitigate supply chain disruptions. In

Line No.

1 addition, the cloud-based platform will support increasing procurement volumes
2 and complexity as the Company expands its energy infrastructure investments. See
3 Exhibit A-24, Schedule N3 Revised, Lines 188-189 for additional details.
4
5 (3) Warehouse Efficiency
6 The Company is seeking recovery for $0.4 million in the Warehouse Efficiency
7 project over the 12 months ending December 31, 2025, as shown on line 18 of
8 Exhibit A-12, Schedule B5.7.1.
9
10 Shipping delays and product availability constraints have significantly increased
11 lead times for critical materials. As a result, the Company's planners and schedulers
12 require improved visibility into contractor-shipped and installable materials. The
13 current SAP environment does not provide the capability to track
14 direct-to-contractor shipments or internal warehouse transfers, which has resulted
15 in material stockpiling and work backlogs. This investment will implement
16 barcoding and radio-frequency identification (RFID) technologies to improve
17 material tracking and enhance SAP Supplier Relationship Management (SRM)
18 functionality for inventory management. These capabilities will provide improved
19 visibility into material locations and availability, supporting more effective
20 planning, scheduling, and execution of field work. See Exhibit A-24, Schedule N3
21 Revised, Line 190 for additional details.

Line No.

1 **C. Plant & Field**

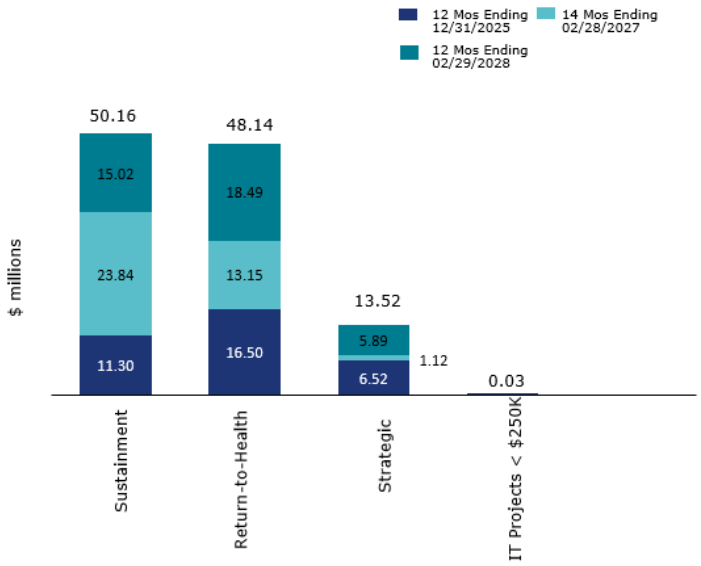
2 **Q78. What are the projected costs for investments in the Plant & Field Portfolio?**

3 A78. As reflected on Line 4 of Exhibit A-12, Schedule B5.7, page 1, capital costs for
4 Plant & Field total $34.3 million for the historical test year 2025, $38.1 million in
5 the bridge period (for the 14 months ending February 28, 2028), and $39.4 million
6 for the projected test period ending February 29, 2028.

7

8 The synopses below provide the total spend for each line item involved in the
9 Company's request for recovery in this rate case. The cost details for projects in
10 this Portfolio broken out by historical period, projected bridge period, and projected
11 test period are provided in Exhibit A-12, Schedule B5.7.4, in columns d, g and h,
12 respectively. Figure 11 represents a high-level view of capital allocation within the
13 Portfolio.

14 Figure 11 Plant & Field – IT Investment



15

Line No.

1 a) Sustainment

2 **Q79. Please explain the Plant & Field Portfolio investment in the Sustainment**
3 **category.**

4 A79. The Company is seeking recovery for $38.8 million in the Sustainment category
5 over the 26 months ending February 29, 2028, and the historical spend of $11.3
6 million in 2025, as shown in lines 1 through 21 of the Capital Expenditures Exhibit
7 A-12, Schedule B5.7.4. These investments are described below.
8
9 (1) Distribution Operations Application Health
10 The Company is seeking recovery for $7.2 million in the Distribution Operations
11 Application Health project over the 26 months ending February 29, 2028, and the
12 historical spend of $1.2 million in 2025, as shown on line 6 of Exhibit A-12,
13 Schedule B5.7.4.
14
15 The Distribution Operations Application Health project is an annual investment
16 supporting approximately 50 IT-supported applications within Distribution
17 Operations (DO). The project includes adding new functionalities to systems such
18 as Crew Management, Pole Top, and Power Track Electric and Storm Restoration
19 to accommodate evolving field operation needs and improve the mobile
20 applications used by DO field workers. Planned improvements include a redesigned
21 Outage Status App with a Supervisory Dashboard, enhancements to our central API
22 module (Plant and Field APIM), and infrastructure updates. These changes aim to
23 improve customer and employee experiences, enabling efficient restoration work
24 by field workers.

Line No.

1 The Company reports a variance of $2.1 million over 24 months ending December
2 31, 2026 than that approved for recovery per Case No. U-21860 Final Order. Of
3 this amount, $0.1 million reflects the 10 % disallowance in 2025, and the remaining
4 $2.0 million reflects additional scope to support long-term system stability and
5 performance. This includes increased sustainment requirements following the
6 migration of the Outage Status Application (OSA) and the Plant and Field Shared
7 API Management (APIM) platform to a Tier 1 cloud foundation. See Exhibit A-24,
8 Schedule N3 Revised, Lines 194 - 197 for additional project details.
9
10 (2) DTE Electric Generation Capacity Application Health
11 The Company is seeking recovery for $1.2 million in the DTE Electric Generation
12 Capacity Application Health project over the 26 months ending February 29, 2028,
13 and the historical spend of $0.7 million in 2025, as shown on line 7 of Exhibit A-
14 12, Schedule B5.7.4.
15
16 The DTE Electric Generation Capacity Application Health project is an annual
17 investment that ensures regular updates to the Generation Supply Management
18 System (GSMS). This system calculates which generation plants to offer into the
19 Midcontinent Independent System Operator (MISO) market, adhering to MISO
20 regulations and remaining current with MISO Shadow Billing. The GSMS vendor
21 targets quarterly releases for application updates which are crucial for compliance
22 and financial planning. The project will also accommodate changes in MISO's
23 back-end system, which could affect the GSMS's connectivity and interactions
24 with MISO. See Exhibit A-24, Schedule N3 Revised, Lines 198 - 201 for additional
25 project details.

Line No.

1 (3) Enterprise Automation – Process Automation

2 The Company is seeking recovery for $1.1 million in the Enterprise Automation –
3 Process Automation project over the 26 months ending February 29, 2028, and a
4 historical expenditure of $0.5 million in 2025, as shown on line 3 of Exhibit A-12,
5 Schedule B5.7.4.
6
7 Enterprise Automation engages in automation initiatives for organizations across
8 Enterprise. The initiatives may involve automating routine tasks/processes,
9 digitizing previously paper-based documents and processes, or producing a
10 platform to standardize, optimize, and/or bring productivity and new capabilities to
11 processes and procedures. This includes providing the ability to perform reporting
12 and data analytics, relevant to the digitized processes, through dashboarding tools.
13 Common digitization initiatives include building forms-based apps, for both mobile
14 and desktop use cases, and creating visualizations or dashboards for reporting and
15 data analytics Use Cases. Common automation initiatives include creating RPAs to
16 perform routine tasks/processes. The Company reports a variance of $9.0 million
17 less over 24 months ending December 31, 2026 than that approved for recovery per
18 Case No. U-21860 Final Order, due to a reduction in project scope. In 2025, the
19 scope of work associated with the Enterprise Automation project reduced to
20 reallocate resources to other priority initiatives, including the ADMS Application
21 and Production Growth. In 2026, the planned Blue Prism upgrade has been deferred
22 to a later time to reallocate resources to other priority initiatives. See Exhibit A-24,
23 Schedule N3 Revised, Lines 202 - 205 for additional project details.

Line No.

1 (4) ESRI Application Health

2 The Company is seeking recovery for $1.0 million in the ESRI Application Health
3 project over the 26 months ending February 29, 2028, and a historical expenditure
4 of $0.5 million in 2025, as shown on line 4 of Exhibit A-12, Schedule B5.7.4.
5
6 The ESRI Application Health project is an annual investment that will continue in
7 2026. This project supports enhancements to the Company's automated mapping
8 system (Geographic Information System or GIS) that supports all GPS mapping
9 data including operating maps and customer-facing outage maps. This investment
10 includes testing and installing service packs and security vulnerability remediation
11 as part of regularly scheduled release enhancements, and significant software and
12 hardware upgrades. Failure to deploy GPS releases would result in inaccurate
13 mapping data. See Exhibit A-24, Schedule N3 Revised, Lines 206 - 209 for
14 additional project details.
15
16 (5) Everyday Daily Plan (EDDP) Application Health
17 The Company is seeking recovery for $0.5 million in the Everyday Daily Plan
18 (EDDP) Application Health project over the 26 months ending February 29, 2028,
19 and a historical expenditure of $0.2 million in 2025, as shown on line 8 of Exhibit
20 A-12, Schedule B5.7.4.
21
22 Distribution Operations (DO) utilizes a unified Everyday Daily Plan (EDDP) web-
23 based tool that seamlessly operates during both storm and non-storm conditions.
24 This tool prioritizes daily work and efficiently assigns field crews to bundled work
25 packages by integrating dispatch priorities for trouble work, configurable storm

Line No.

1 settings, and planned work priorities. The interface and functionality will remain
2 consistent regardless of operational conditions, promoting ease of use and
3 adaptability. This project will implement bug fixes and application monitoring to
4 ensure the tool is operational and available 24/7. The EDDP tool will improve
5 operational efficiency, customer satisfaction, and field crew effectiveness. See
6 Exhibit A-24, Schedule N3 Revised, Lines 210 - 213 for additional project details.
7
8 (6) Fuel Supply Application Health
9 The Company is seeking recovery for $0.9 million in the Fuel Supply Application
10 Health project over the 26 months ending February 29, 2028, and a historical
11 expenditure of $0.5 million in 2025, as shown on line 10 of Exhibit A-12, Schedule
12 B5.7.4.
13
14 Fuel Supply Application Health project aims to manage and maintain key
15 applications used by Fuel Supply. These applications include Automated Rail
16 Receipt (AAR), GenMart and Energy Trading and Risk Management (ETRM).
17 Starting in 2022, quarterly vendor releases to ETRM and AAR systems were tested
18 and deployed. These upgrades are required to remain current under vendor support
19 and provide new product capabilities to end users who were included in upgrades.
20 In 2026, the ARR and ETRM applications will receive new capabilities to automate
21 workflows, enhance usability, and reduce redundancies in Fuel Supply's business
22 processes. Quarterly vendor releases are scheduled to support these systems, along
23 with three annual updates to maintain platform currency and introduce key
24 improvements throughout 2026 through 2028. See Exhibit A-24, Schedule N3
25 Revised, Lines 214 - 217 for additional project details.

Line No.

1 (7) IFS Mobile Workforce Management (MWM) Application Health

2 The Company is seeking recovery for $0.9 million in the IFS Mobile Workforce
3 Management (MWM) Application Health project over the 26 months ending
4 February 29, 2028, as shown on line 11 of Exhibit A-12, Schedule B5.7.4.
5
6 This investment represents the sustainment effort for the IFS system, implemented
7 as part of the FSE Replacement Project approved as part of Case No. U-21860 Final
8 Order. It maintains a fully supported and secure field service management platform
9 by ensuring timely maintenance, security updates, including minor and major
10 software upgrades, plus code or configuration modifications to resolve significant
11 issues or outages. Through these sustainment efforts, the IFS platform will continue
12 to optimize field service operations with efficient scheduling and dispatching tools,
13 enhance mobile access for field technicians to view job details and update statuses,
14 and streamline work order management for accurate creation, tracking, and
15 completion. This investment is essential for reliable field operations, enabling
16 timely service delivery, and supporting customer safety across DTE Electric's
17 service territory. Exhibit A-24, Schedule N3 Revised, Lines 218 - 219 for additional
18 project details.
19
20 (8) ITS ADMS Application Health

21 The Company is seeking recovery for $4.0 million in the Information Technology
22 System (ITS) - Advanced Distribution Management System (ADMS) Application
23 Health project over the 26 months ending February 29, 2028, and a historical
24 expenditure of $1.3 million in 2025, as shown on line 12 of Exhibit A-12, Schedule
25 B5.7.4.

Line No.

1 The ITS ADMS Application Health Program covers a suite of applications that
2 support safe and effective operation in the Electric System Operations Center
3 (ESOC) and for Distribution Operations Dispatch. These applications include the
4 Outage Management System (OMS), Distribution Management System (DMS),
5 Energy management System (EMS), Generation Management System (GMS), and
6 Systems Operations Management (SOM). This project provides support and
7 updates to these applications and for integration infrastructure (ESB or Enterprise
8 Service Bus) that connects all aspects of ADMS to DTE legacy systems. Investment
9 in these required enhancements, upgrades, and maintenance reduces the risk of
10 system failure or malfunction, which can have serious consequences on the safe
11 and reliable operation of the electrical grid.
12
13 The Company reports a variance of $1.1 million more over 24 months ending
14 December 31, 2026 than that approved for recovery per Case No. U-21860 Final
15 Order. Of this amount, $0.1 million reflects the 10 percent disallowance in 2025
16 per final order U-21860. The remaining $1.0 million is for additional costs
17 associated with expanded Enterprise Service Bus (ESB) scope, including the
18 implementation of Operational Decision Manager (ODM) redundancy to address
19 single-point-of-failure risk. See Exhibit A-24, Schedule N3 Revised, Lines 220 -
20 223 for additional project details.
21
22 (9) ITS-SRS Application Health
23 The Company is seeking recovery for $1.0 million in the Information Technology
24 System (ITS) Supervisory Control and Data Acquisition Realtime Support (SRS)

Line No.

Application Health project over the 24 months ending December 31, 2025, as shown on line 13 of Exhibit A-12, Schedule B5.7.4.

The ITS-SRS Application Health Investment supports the core OSI (Open Systems Interconnection) system and vendor relationship used for grid operations. The ITS-SRS application also supports the NERC (North American Electric Reliability Corporation) compliance activities for ADMS (Advanced Distribution Management System), GMS (Generation Management System), and the MOC (Market Operations Center). Investment is required to keep these systems available and performing optimally, ensuring the smooth functioning of the electrical grid.

The Company is reporting a variance of $0.5 million more over 24 months ending December 31, 2026 than that approved for recovery per Case No. U-21860 Final Order. Of this amount, $0.05 million is due to 10% disallowance by Commission as part of final order in Case No. U-21860. The remaining $0.45 million is for support needed for ADMS Hardware replacements, GMS System Upgrades and eSCADA Environment upgrades for Renewable Solar and Wind. See Exhibit A-24, Schedule N3 Revised, Line 224 for additional project details.

(10) Maximo Application Health

The Company is seeking recovery for $2.7 million in the Maximo Application Health project over the over the 26 months ending February 29, 2028, as shown on line 5 of Exhibit A-12, Schedule B5.7.4.

Line No.

1 DTE uses Maximo as the enterprise work and asset management platform. This
2 project will focus on several key areas, including database health, to ensure data
3 integrity and consistency across environments, to ensure Maximo's reliability,
4 security, and efficiency in support of the Company's business operations. The
5 project will upgrade to a supported software versioning system for better code
6 traceability and protect privileged identities using an enterprise privilege access
7 management solution. Benefits include improved data management efficiency and
8 application performance, enhanced data integrity and consistency, faster
9 deployments through automated testing, and reduced risk of unauthorized access to
10 Maximo credentials. The project will permit DTE to continue to utilize Maximo by
11 leveraging existing archiving solutions and implementing necessary upgrades and
12 security measures.
13
14 The Company reports a variance of $0.5 million more over 24 months ending
15 December 31, 2026 than that approved for recovery per Case No. U-21860 Final
16 Order. This variance was primarily driven by adjustment to how planned work was
17 sequenced, packaged, and released in 2026. Under an Agile delivery model, related
18 enhancements were delivered as integrated system releases rather than as individual
19 activities, resulting in costs being recognized as capital in alignment with the
20 delivery of durable system functionality. See Exhibit A-24, Schedule N3 Revised,
21 Lines 225 – 227 for additional project details.
22
23 (11) Network Reliability and Monitoring

Line No.

1 The Company is seeking historical recovery for $1.0 million in the Network
2 Reliability and Monitoring project in 2025, as shown on line 14 of Exhibit A-12,
3 Schedule B5.7.4.
4
5 Network monitoring provides real-time response capability to respond to and
6 resolve performance or availability issues before the technology asset impacts
7 business operations. This project is required to maintain tracking and monitoring
8 tools to monitor, collect, and surface issues regarding application and infrastructure
9 performance and involves fine tuning tools to reduce the required manual efforts to
10 gain visibility on asset health.
11
12 The Company reports a variance of $0.24 million over 24 months ending December
13 31, 2026 than that approved for recovery per Case No. U-21860 Final Order. This
14 overspend variance is offset by the underspend in Advance Metering Infrastructure
15 (AMI) Application Health project. See Exhibit A-24, Schedule N3 Revised, Line
16 228 for additional project details.
17
18 (12) Nuclear Generation Business Systems Replacement
19 The Company is seeking recovery for $1.5 million in the Nuclear Generation
20 Business Systems Replacement project over the over the 26 months ending
21 February 29, 2028, and a historical expenditure of $0.6 million in 2025, as shown
22 on line 15 of Exhibit A-12, Schedule B5.7.4.

23 Nuclear Generation has 36 applications that require regular security vulnerability
24 remediation. These applications require annual software, hardware, and database

Line No.

1 environment upgrades or replacement due to regulatory changes, obsolescence,
2 security vulnerabilities, and continued protection from the risk of system failure
3 and possible cyber-attack. This project will refresh the server stack that supports
4 the Nuclear Generation application environment with current long-term vendor
5 supported systems that represent best security practices and increase system
6 reliability while reducing security and system outage vulnerabilities. See Exhibit
7 A-24, Schedule N3 Revised, Lines 229 - 232 for additional project details.
8
9 (13) Production Growth
10 The Company is seeking recovery for $2.8 million in the Production Growth project
11 over the over the 26 months ending February 29, 2028, and a historical expenditure
12 of $0.5 million in 2025, as shown on line 16 of Exhibit A-12, Schedule B5.7.4.
13
14 Production Growth is an annual investment that will deliver the infrastructure
15 capacity and performance enhancements necessary to sustain business-critical
16 operations as demand continues to grow. Specifically, the initiative will provision
17 additional computing power, storage capacity, database availability, and middle-
18 tier infrastructure ensuring that resources scale appropriately with usage.
19
20 The scope is directly tied to supporting key business applications and processes,
21 including meter reads, outage management, field service, and asset health
22 management. By aligning capital investment with measurable workload growth in
23 these areas, the project ensures that system performance, scalability, reliability, and
24 availability targets are maintained. Additionally, this investment will ensure system
25 performance remains within defined CPU, memory, and response-time thresholds

Line No.

1 support business applications under increasing load and resiliency requirements
2 and accommodate a growing user base and expanding usage across the enterprise.
3 The Company reports a variance of $0.7 million less for the 12-month period
4 ending December 31, 2026, reflecting scope deferral for production growth
5 activities for ESB, ESRI, and Distribution Operations Applications. See Exhibit A-
6 24, Schedule N3 Revised, Lines 233 - 236 for additional project details.
7
8 (14) Renewable Operations Application Health
9 The Company is seeking recovery for $0.4 million in the Renewable Operations
10 Application Health project over the 26 months ending February 29, 2028, and a
11 historical expenditure of $0.1 million in 2025, as shown on line 17 of Exhibit A-
12 12, Schedule B5.7.4.
13
14 The Renewable Energy Operations organization performs monitoring, operations,
15 and maintenance of all Company-owned wind and solar assets. Renewable assets
16 include IT infrastructure, applications, and systems for the existing ten wind
17 facilities and seven solar parks. Operations include predictive analytics on turbine
18 health data, case management, work scheduling, and work tracking. Key activities
19 involve application upgrades, patching support, and maintaining asset health for
20 telecommunications and data center infrastructure. See Exhibit A- 24, Schedule N3
21 Revised, Lines 237 - 240 for additional project details.

Line No.

1 (15) Storm Simulation Lab Application Health

2 The Company is seeking recovery for $3.3 million in the Storm Simulation Lab
3 Application Health Application Health project over the 26 months ending February
4 29, 2028 as shown on line 19 of Exhibit A-12, Schedule B5.7.4.
5
6 From 2021 through 2023, the Company experienced 13 severe weather-related
7 events, each exceeding 110,000 unique customer outages, with an average of
8 approximately 274,000 customers impacted per event. These significant outage
9 events, referred to as "Catastrophic" or "CAT Storms," affected the Company's IT
10 systems approximately 60 percent of the time, with IT-related outages lasting an
11 average of 6.8 hours. During these events, customers were at times unable to report
12 outages or hazards and received delayed or inaccurate restoration information. Field
13 crews were required to rely on manual processes for planning, scheduling,
14 dispatching, and status updates, which reduced operational efficiency and slowed
15 restoration efforts. Analysis of IT major incidents associated with these events
16 indicates that, in approximately 60 percent of cases, system outages were caused
17 by demand levels that exceeded the design capacity of related and interconnected
18 systems. The Storm Simulation Lab project is intended to test and enhance the
19 resilience of the Company's storm-critical IT systems by identifying and addressing
20 load-related system vulnerabilities before they impact customers. By simulating
21 storm conditions, the lab will enable proactive testing and validation of system
22 performance under high-demand scenarios. This initiative supports the Company's
23 objectives of improving grid reliability, enabling timely restoration, and
24 minimizing outage durations during severe weather events. Applications evaluated
25 through this effort include the Outage Status Application (OSA), System Outage

Line No.

Screen (SOS), the central Application Programming Interface module (Plant and Field APIM), Public Protection Chatbot, Every Day Daily Plan (EDDP), Utility Restoration Management Application (URMA), and other storm-critical systems. See Exhibit A-24, Schedule N3 Revised, Lines 242 - 244 for additional project details.

(16) System for Fossil Generation for Coal and Gas

The Company is seeking recovery for $1.0 million in the System for Fossil Generation for Coal and Gas project over the 26 months ending February 29, 2028, and a historical expenditure of $0.4 million in 2025, as shown on line 9 of Exhibit A-12, Schedule B5.7.4.

The System for Fossil Generation for Coal and Gas project will implement the latest vendor releases and software patches for Fossil Generation's (FosGen's)/Energy Supply's application suite, which includes Akwire, Plantview, the Laboratory Management System (LMS), the Overtime Management System (OTM), and the Power Plant Management System (P3M). All of these applications require monthly releases and hardware and software upgrades in alignment with accommodating vendor releases. The project will update the Generating Availability Data System (GADS) reporting process as needed, especially to reduce manual workarounds and transition manual entry into automated or programmatic features. Data validity is essential on the GADS system, as it not only affects operations but is also reviewed by MISO and federal regulatory agencies including FERC. Therefore, failure to install required updates presents an unacceptably high risk of data inaccuracy. See Exhibit A-24, Schedule N3 Revised, Lines 246-249 for additional project details.

Line No.

1 (17) System Outage Screen (SOS) Application Health

2 The Company is seeking recovery for $3.1 million in the System Outage Screen
3 (SOS) Application Health project over the 26 months ending February 29, 2028,
4 and a historical expenditure of $0.8 million in 2025 as shown on line 21 of Exhibit
5 A-12, Schedule B5.7.4.
6
7 This investment sustains the System Outage Screen (SOS), a critical web-based
8 application that Distribution Operations relies on to streamline outage restoration
9 activities for both routine and emergency scenarios. Widely used by Electrical
10 Dispatch Operations, field teams, and Regional Control Operations (RCO) teams,
11 SOS provides essential visibility into outage status for Overhead (OH) and
12 Underground (UG) work, while supporting coordinated response efforts, automated
13 crew assignments, and real-time data integration with Electrical Dispatch and
14 Outage Dashboards. These sustainment efforts maintain reliable outage
15 management and support the company's service reliability commitments.
16
17 The Company reports a variance of $0.9 million more over 24 months ending
18 December 31, 2026 than that approved for recovery per Case No. U-21860 Final
19 Order. This variance is for additional vendor costs required to support the
20 sustainment of the System Outage Screen (SOS), including specialized support
21 necessary to maintain system performance, availability, and integration with
22 outage-related systems under increased operational and emergency-response
23 demands. See Exhibit A-24, Schedule N3 Revised, Lines 250-253 for additional
24 project details.

Line No.

b) Return-to-Health

Q80. What is the Plant & Field Portfolio investment in the Return-to-Health category?

A80. The Company is seeking recovery for $31.6 million in the Return-to-Health category of the Plant & Field Portfolio over the 26 months ending February 29, 2028, and a historical expenditure of $16.5 million in 2025 as shown in lines 22 - 30 of the Capital Expenditures Exhibit A-12, Schedule B5.7.4. These investments are described below.

(1) DO Business Warehouse (DOBW) Replacement

The company is seeking recovery for $0.25 million in DO Business Warehouse (DOBW) Replacement project over the 26 months ending February 29, 2028, as shown on line 25 of Exhibit A-12, Schedule B5.7.4.

The Distributed Operations Business Warehouse (DOBW) system is currently used to track costs, employees, purchase orders, purchase requisitions, work data, master material items, asset specifications, locations, service receipts, and organizational structure/hierarchy. The system is built on an old Oracle database and is no longer sufficient to meet the needs of the DO Business Unit because it is end of life. and its associated reports and applications are difficult to maintain and support.

This investment supports the solution for moving away from the end-of-life DO Business Warehouse (DOBW) system, migrating the DOBW system's data to the Enterprise DataLake, and redeveloping reports and applications using modern

Line No.

1 reporting tools and technologies. See Exhibit A-24, Schedule N3 Revised, Line 255
2 for additional project details.
3
4 (2) Generation Optimization and Energy Accounting Cloud Migration
5 The Company is seeking recovery for $0.6 million in Generation Optimization and
6 Energy Accounting Cloud Migration project over the 26 months ending February
7 29, 2028, as shown on line 30 of Exhibit A-12, Schedule B5.7.4.
8
9 This investment will support migration of the Company's energy accounting and
10 market operations platform to the PCI Energy Solutions cloud environment,
11 addressing aging on-premises infrastructure, rising operational risk, and increasing
12 system complexity. Migration eliminates the need for a hardware refresh, replaces
13 the internally developed EAGL application with a proven vendor solution, reduces
14 cybersecurity and business continuity risk, and aligns with PCI's cloud-based
15 product roadmap required for ongoing MISO market participation. It also provides
16 a scalable and sustainable foundation to support the Company's growing portfolio
17 of renewable and storage generation assets while enabling the retirement of 54 end-
18 of-life servers. See Exhibit A-24, Schedule N3 Revised, Line 261 for additional
19 project details.
20
21 (3) Maximo Uplift to Maximo Application Suite
22 The Company is seeking recovery for $20.4 million in the Maximo uplift to
23 Maximo Application Suite project over the 26 months ending February 29, 2028,
24 as shown on line 23 of Exhibit A-12, Schedule B5.7.4.

Line No.

1 This investment is a consolidation of two previously presented projects in U-21860
2 - Corporate Instance - Maximo Application Suite Upgrade Phase 1 and Corporate
3 Instance - Enterprise Maximo Transformation.
4 This investiment supports the long-term reliability, safety, and operational
5 effectiveness of the organization by modernizing a critical Enterprise Work and
6 Asset Management (EWAM) capability that underpins how work is planned,
7 executed, and governed across multiple business units. As described further below,
8 EWAM is foundational to maintaining critical assets, coordinating workforce
9 activities, and ensuring consistent service delivery.
10
11 The Company uses Maximo as its EWAM platform and currently operates on
12 version 7.6, which has been in service for over 20 years and will reach end of vendor
13 support in April 2027, making this transition imperative. Over that 20-year period,
14 the platform has been extensively customized to meet evolving operational needs.
15 Many of the features added through customization did not exist natively in the
16 application at the time they were developed. This approach allowed the Company
17 to preserve the usefulness of the existing system and extend its operational life for
18 as long as responsibly possible.
19
20 As the Maximo application has matured, many of those capabilities added through
21 customization now exist natively in Maximo Application Suite (MAS), which is an
22 updated version of the Maximo EWAM platform. MAS is a broader suite of
23 applications built on a common platform, enabling extensions and add-ons that
24 leverage core functionality to deliver additional capabilities.

Line No.

Additionally, the existing platform can no longer sustainably support operational demands and future growth due to the accumulated weight of that customization and the limits it places on scalability. Scalability is critical here: MAS is designed as a scalable platform that will support growing asset volumes, users, system integrations, and data across the enterprise. As the Company's asset portfolio grows in complexity and additional business units seek to leverage the platform, a scalable foundation ensures the system can accommodate expanded adoption and future capability growth without repeated infrastructure changes or increased operational risk.

Continued reliance on the current platform increases operational risk, limits standardization, and drives inefficiencies. However, migrating from a heavily customized configuration to a standardized modern version requires deliberate planning and execution. This project will enable an upgrade from an older version to a newer version of the same platform that requires updated architecture, infrastructure, and enabling technologies. This investment mitigates those risks presented by the age and limitations of the existing infrastructure by establishing a modern, unified platform that enables standardized processes, improves data integrity, and enhances operational visibility across the enterprise.

Modernizing EWAM enables the Company to shift towards a more proactive, data-informed operating model. Specifically, MAS centralizes asset and work data to provide clear visibility into asset health and performance, enabling better planning and maintenance prioritization based on condition and criticality. By applying analytics and predictive insights, capabilities that the existing platform does not

Line No.

1 possess, MAS helps reduce unplanned outages and extend asset life through earlier,
2 data-driven intervention. These capabilities become increasingly critical as asset
3 portfolios grow in complexity and performance expectations continue to rise.
4 This investment also supports workforce effectiveness and sustainability. Field and
5 operational staff rely on EWAM systems daily to receive work assignments, review
6 asset history, record inspections, and capture labor and materials directly against
7 work orders. These systems enable crews, planners, and supervisors to stay aligned
8 on priorities, progress, and compliance. For example, a field technician responding
9 to a service request can use MAS on a mobile device to pull up the full maintenance
10 history of an asset, record inspection findings in real time, and close out the work
11 order on-site — eliminating paper-based processes, reducing data lag, and ensuring
12 supervisors have immediate visibility into work status. With MAS, this daily
13 experience improves through better mobile performance, real-time data visibility,
14 and integrated analytics — allowing faster updates, more informed
15 decision-making, and proactive maintenance that reduces unplanned outages and
16 improves overall productivity. Improved usability, integrated mobile functionality,
17 and standardized processes also reduce administrative burden, improve data
18 quality, simplify training, and support consistent execution across all business
19 units.
20
21 This investment addresses the escalating cost and uncertainty of maintaining an
22 aging, highly customized legacy EWAM platform. Continuing to operate on the
23 current platform would perpetuate technical debt — the accumulating burden of
24 maintaining a system increasingly misaligned with IBM's supported architecture
25 and roadmap — driving continued reliance on workarounds, higher maintenance

Line No.

1 effort, and a limited ability to adopt modern capabilities. Transitioning to a
2 standardized and scalable solution reduces long-term maintenance costs, improves
3 system reliability, and establishes a more predictable and sustainable cost structure.
4 The Company reports a variance of $9.9 million less over 24 months ending
5 December 31, 2026 than that approved for recovery per Case No. U-21860 Final
6 Order. This variance reflects the deferral of spending associated with two
7 previously approved projects in that case — Corporate Instance - Maximo
8 Application Suite Upgrade Phase 1 and Corporate Instance - Enterprise Maximo
9 Transformation — while the Company reevaluated its implementation approach.
10 The preliminary scope for this project focused on core IT system upgrades. As a
11 result of its reevaluated implementation approach, the Company completed a
12 detailed vendor-led assessment of the existing Maximo implementation in late
13 2024, which determined that DTE's Maximo environment is substantially more
14 complex than initially contemplated, including extensive integrations,
15 customizations, and operational dependencies across multiple business units.
16
17 The assessment determined that a traditional in-place upgrade is not possible due
18 to the age and limitations of the current infrastructure and technology stack. Based
19 on this determination, the assessment recommended an uplift approach versus an
20 in-place upgrade. An in-place upgrade is a technical version update that largely
21 preserves the existing architecture, infrastructure, and database environment, with
22 the primary objective of maintaining vendor support. An uplift strategy, by contrast,
23 involves moving to the newer Maximo Application Suite (MAS) platform and
24 requires new architecture, infrastructure, and enabling technologies (a complete
25 replatforming). The uplift approach is materially more complex than a routine

Line No.

upgrade. Consistent with the vendor led assessment recommendation, the Company adopted an uplift strategy that requires replatforming to modern technologies and selectively migrating relevant and validated data to support a responsible transition to Maximo Application Suite. The investment requested in this case therefore reflects a more complete and accurate scope necessary to address these complexities and reduce long-term operational risk. This request also reflects business labor and organizational change management (OCM) costs to ensure effective implementation, training, and sustained operational adoption. See Exhibit A-24, Schedule N3 Revised, Lines 262-263 for additional project details.

Q81. What are the operational, financial, and risk implications of continuing to rely on the existing Enterprise Work and Asset Management system rather than making this investment?

A81. Continuing to rely on the existing Enterprise Work and Asset Management system would increase operational and security risk due to aging, unsupported technology, growing system fragility and limited scalability. As the Company expands its operations and manages a growing asset base, there is increased risk that the current system may not reliably support additional workload and transaction volume. From a financial and risk perspective, further deferral would drive higher long-term costs and reliability exposure, whereas the proposed investment represents a prudent, least-risk approach to sustaining critical operations.

Q82. How does this investment reduce long-term costs and operational risk when compared to continued upgrades and maintenance of the current highly customized platform?

Line No.

A82. This investment addresses long-term cost and operational risk by reducing reliance on a highly customized legacy platform whose underlying technology is no longer vendor-supported and cannot be upgraded. The current stack also faces increasing compatibility challenges with modern host systems, which elevates operational risk over time. Continued operation would require ongoing effort to sustain an increasingly complex and constrained environment, with limited modernization options. Transitioning to a modern EWAM platform improves system reliability, reduces reliance on specialized resources, and establishes a more sustainable and predictable cost structure while positioning the organization to support future technology adoption.

Q83. In what ways does modernizing the EWAM system support workforce effectiveness, regulatory compliance, and the organization's ability to meet future operational demands?

A83. Modernizing the EWAM system supports workforce effectiveness through improved usability, mobile capabilities, and more standardized processes, which may reduce administrative effort and support consistent data practices. A unified, vendor-supported platform strengthens governance, data integrity, and operational visibility, supporting regulatory compliance and oversight. In addition, the modernized MAS platform enables access to additional vendor-provided capabilities—such as renewables management, predictive analytics, and artificial intelligence—and allows the organization to adopt future modules as they become available, which is not feasible on the current system nearing end of support. These capabilities are intended to better support evolving operational requirements over time.

Line No.

c) Strategic

Q84. What is the Plant & Field Portfolio investment in the Strategic category?

A84. The Company is seeking recovery for $7.0 million in the Strategic category of the Plant & Field Portfolio over the 26 months ending February 29, 2028, and the historical spend of $6.5 million over the 12 months ending December 31, 2025, as shown in lines 31 and 32 of the Capital Expenditures - Exhibit A-12, Schedule B5.7.4. These investments are described below.

(1) Fermi Supply Chain Transformation

The Company is seeking recovery for $7.0 million in the Fermi Supply Chain Transformation portfolio over the 26-month period ending February 29, 2028, as shown on line 31 of Exhibit A-12, Schedule B5.7.4.

This investment will support the correction of defective integrations between supply chain and enterprise systems, restoring functionality, improving inventory accuracy, and reducing administrative and operational burden.

The investment will strengthen core supply chain and inventory processes, reduce manual intervention, improve reporting, and address system limitations and data inconsistencies introduced during prior system migrations. These improvements are necessary to support nuclear regulatory compliance requirements, streamline work management and operations, and reduce long-term operational and compliance risk associated with fragmented and inefficient system integrations. See Exhibit A-24, Schedule N3 Revised, Line 265 for additional project details.

Line No.

1 **D. Customer IT**

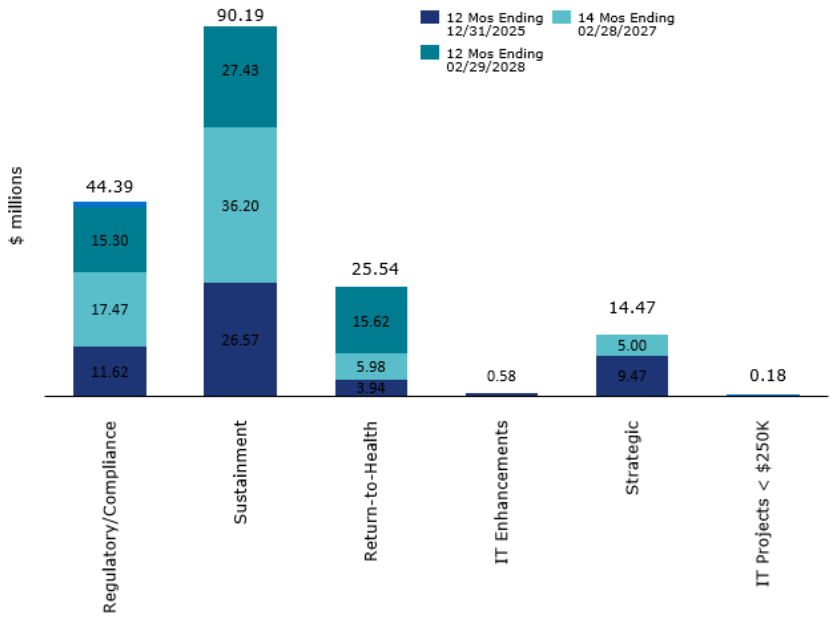
2 **Q85. What are the projected costs for investments in the Customer IT Portfolio?**

3 A85. As reflected on line 3 of Exhibit A-12, Schedule B5.7, page 1, capital costs for the
4 investments in the Customer IT Portfolio total $52.2 million for the historical period
5 year ending December 31, 2025, $64.6 million in the bridge period (for the 14
6 months ending February 28, 2027), and $58.5 million for the projected test period
7 ending February 29, 2028.

8 The synopses below provide the total spend for each line item the Company
9 requests in this rate case. The cost details for projects in the Customer IT Portfolio
10 broken out by historical period, projected bridge period, and projected test period
11 are provided in Exhibit A-12, Schedule B5.7.2, in columns (d), (g) and (h),
12 respectively. Figure 12 below represents a high-level view of capital allocations
13 within the Portfolio.

14

15 Figure 12 Customer IT Investment



Line No.

1 1. Regulatory/Compliance

2 **Q86. Please explain the Customer IT Portfolio investments in the Regulatory /**
3 **Compliance category.**

4 A86. The Company is seeking recovery for $32.8 million in the regulatory Compliance
5 category of the Customer IT Portfolio over the 26 months ending February 29,
6 2028, and a historical expenditure of $11.6 million in 2025 as shown in lines 1-7 of
7 the Capital Expenditures Exhibit A-12, Schedule B5.7.2. The investments are non-
8 discretionary projects that must satisfy MPSC requirements, rate orders, and other
9 industry regulations and compliance items that are necessary to serve customers.
10
11 **Q87. What are the Company's investments in the five MIGreenPower (MIGP)**
12 **Regulatory / Compliance projects?**

13 A87. The Company is seeking recovery for $24.8 million over the 26 months ending
14 February 29, 2028, and the historical spend of $9.0 million in 2025 as shown in
15 Exhibit A-12 Schedule B5.7.2, in the expansion and creation of products and
16 services that allow customers to contribute to a cleaner environment. These
17 investments satisfy the Company's commitments to the MPSC and customers under
18 DTE Electric's renewable energy plan (REP) and voluntary green pricing (VGP)
19 cases originally approved in Case Nos. U-20851 and U-20713.
20
21 Each of the MIGP tariffs have been approved by the MPSC for implementation,
22 with the associated capital dollars reflecting the investment necessary to build the
23 required fixed or volumetric charges in the CR&B system, enroll or reserve
24 customer interest in a specific MIGP program, update the Company's MIGP

Line No.

1 Website, or create supporting internal dashboarding and reporting to enable
2 efficient management of the MIGP programs.
3
4 (1) MIGP Customer – Requested Renewable Energy Projects
5 The Company is seeking recovery for $10 million over 26 months ending Feb 29,
6 2028 and historical recovery of $5.9 million in 2025 as shown on line 3 of Exhibit
7 A-12, Schedule B5.7.2. This investment will enable the extension of the Customer-
8 requested Renewable Energy Projects for creating the billing, reporting, and web
9 infrastructure for other Large DTE Electric customers to have dedicated renewable
10 energy assets to support their sustainability goals. Customer-requested renewable
11 energy projects are unique contracts between a customer and DTE to build
12 dedicated renewable assets to offset their electric use. In addition to building the
13 programs per the contracts, these unique contracts require the creation and
14 integration of a new product named "customer-requested renewable energy
15 projects" into the SAP CR&B system. This project will include end-to-end
16 enhancements to the CR&B system that will include billing, reporting, accounting,
17 and enrollment functionality for individual customer-requested projects, and any
18 additional updates to fulfill the Company's commitment under these contracts.
19
20 The Company reports a total variance of $3.9 million more over 24 months ending
21 December 31, 2026 than that approved for recovery per Case No. U-21860 Final
22 Order. Of this amount, $0.5 million is due to 10% disallowance in 2025. The
23 remaining $3.4 million variance is primarily driven by timing and scope changes in
24 capital work. Of this amount, $3.0 million reflects the deferral of capital work
25 originally planned for 2024 into 2026 due to delays in Solar project construction.

Line No.

1 This deferred work includes the development of new billing options and formats,
2 as well as enhanced reporting capabilities using SAP Business Warehouse (BW)
3 and SAP Analytics Cloud (SAC). In addition, $0.4 million of the variance is for the
4 incremental spending associated with Sales Cloud enhancement work. See Exhibit
5 A-24, Schedule N3 Revised, lines 268-271 for additional project details.
6
7 (2) MIGP Low Income Solar Pilot
8 The Company is seeking recovery of $2.0 million over a 26-month period ending
9 February 29, 2028 for the MIGP Low Income Solar Pilot project as shown on line
10 5 of Exhibit A-12, Schedule B5.7.2.
11
12 This investment supports the integration of the Low Income Solar Pilot into the
13 Customer Relationship and Billing (CR&B) system, including the ability to enroll
14 and unenroll customers, apply bill credits to customer invoices, generate enrollment
15 and revenue reports, update the DTE MIGreenPower website, and develop training
16 materials and customer and other stakeholder notifications. The project scope
17 includes enhancements to SAP Billing and the MIGreenPower (MIGP) enrollment
18 program, updates to customer notification templates, enhancements to SAP
19 Commerce Cloud, and expanded reporting capabilities within SAP Business
20 Warehouse (BW) and SAP Commerce Cloud.
21
22 The Company reports a variance of $2.0 million less over 24 months ending
23 December 31, 2026 than that approved for recovery per Case No. U-21860 Final
24 Order, due to the deferral of project activities. The Pilot program is taking longer
25 than originally anticipated to launch, primarily due to a lack of funding associated

Line No.

1 with multiple construction initiatives in low-income areas. As a result of this delay,
2 the Company is not yet prepared to enroll or bill customers for the Pilot program.
3 Additional project details are provided in Exhibit A-24, Schedule N3 Revised, Line
4 273 for additional project details.
5
6 (3) MIGP Scope 3 Billing and Enrollment
7 The Company is seeking recovery for $4.6 million over 26 months ending Feb 29,
8 2028 as shown on line 6 of Exhibit A-12, Schedule B5.7.2 to allow for sponsored
9 MIGP enrollment per the Section 61 agreement. Through this project, customers
10 will have the ability to incur the renewable energy charges of another customer.
11 For example, a business could elect to be billed for the renewable energy charges
12 of its employees that enroll in the MIGP program. Similar in scope to many of the
13 MIGP renewable projects, this project will include end-to-end enhancements to the
14 CR&B system that will include the required billing, accounting, and reporting
15 functionality.
16
17 The Company reports a variance of $3.5 million less over 24 months ending
18 December 31, 2026 than that approved for recovery per Case No. U-21860 Final
19 Order. This variance reflects the deferral of project activities to allow for
20 completion of activities related to Customer-Requested Renewable Energy and
21 Rider 17. Completion of these initiatives enables the Company to offer programs
22 that allow customers to voluntarily purchase electricity generated from renewable
23 resources. See Exhibit A-24, Schedule N3 Revised, Line 274 for additional project
24 details.

Line No.

1 (4) Rider 17 – MIGreenPower, Residential and Small Commercial & Industrial
2 The Company is seeking recovery for $6.9 million over 26 months ending Feb 29,
3 2028 and historical recovery of $3.1 million in 2025 in the Rider 17 –
4 MIGreenPower, Residential and Small Commercial & Industrial project, as shown
5 on line 7 of Exhibit A-12, Schedule B5.7.2. This project replaces the Rider 19
6 MIGP Large Commercial & Industrial project, as Rider 19 ended on August 19,
7 2022, and has been merged with Rider 17. The project scope includes CR&B
8 system changes required to create a fixed price offering for large customers and the
9 ability to enroll residential and streetlighting accounts, bill customers, and other
10 enhancements to manage and administer the program. See Exhibit A-24, Schedule
11 N3 Revised, Lines 279 - 282 for additional project details.
12
13 (5) Regulatory Compliance
14 The Company is seeking recovery for $6.2 million in Regulatory Compliance
15 project over the 26 months ending February 29, 2028, and the historical spend of
16 $2.6 million in 2025, as shown on line 2 of Exhibit A-12, Schedule B5.7.2.
17
18 This annual investment funds CR&B and reporting system changes necessary to
19 comply with the outcome of any MPSC rate orders, to provide funding for emerging
20 regulatory compliance items, and to fund the implementation of new rates and
21 programs as approved by the MPSC. This project continues to ensure there is
22 sufficient funding for planned and emergent revisions to electric rates, amendments
23 to rate schedules and rules governing the distribution and supply of electric energy,
24 and any other modifications of DTE Electric rates in accordance with MPSC orders.

Line No.

1 See Exhibit A-24, Schedule N3 Revised, Lines 275-278 for additional project
2 details.
3 2. Sustainment
4 **Q88. Please explain the Customer IT Portfolio investments in the Sustainment**
5 **category.**
6 A88. The Company will invest $63.6 million in the Sustainment category of the
7 Customer IT Portfolio over the 26 months ending February 29, 2028, and a
8 historical spend of $26.6 million over the 12 months ending December 31, 2025,
9 as shown in lines 8 through 24 of the Capital Expenditures Exhibit A-12, Schedule
10 B5.7.2. These investments are described below.
11
12 (1) AEM License Renewal
13 The Company is seeking recovery for $1.9 million in the AEM License Renewal
14 project over the 26 months ending February 29, 2028, as shown on line 8 of Exhibit
15 A-12, Schedule B5.7.2.
16
17 The investments support a 3-year license renewal of Adobe Experience Manager
18 (AEM) which is a digital customer experience platform that enables Corporate
19 Communications to author and publish static web content to DTE's customer web
20 channel, dteenergy.com. This is a critical business application for Corporate
21 Communications and Customer Service. The Saas Solution supports the business
22 model that allows for Corporate Communications to manage customer-facing web
23 content. DTE must react and comply with requirements of our business channels to
24 provide content to our customers. If we do nothing our web self-service channel
25 will stagnate and platform will not be running on the latest releases/patches which

Line No.

could impact security and application performance. Additional project details are provided in Exhibit A-24, Schedule N3 Revised, Line 283 for additional project details.

(2) Cloud Services Application Health - Cloud Platform Enterprise Agreement (CPEA)

The Company is seeking recovery for $1.0 million in the Cloud Services Application Health - Cloud Platform Enterprise Agreement (CPEA) project over the 14 months ending February 28, 2027 as shown on line 20 of Exhibit A-12, Schedule B5.7.2.

This investment supports the Cloud Platform Enterprise Agreement (CPEA), which is a consumption-based model that allows the Company to utilize cloud credits based on actual usage. The associated software licensing has a useful life of no less than three years. The CPEA supports ongoing enhancements necessary for the implementation of hardware and environment upgrades, remediation of security vulnerabilities, and the adoption of both major and minor software releases. In addition, this solution enables the Company to continue investing in the upgrades and application development required to maintain the operational stability and functionality of the cloud-based application systems. Additional project details are provided in Exhibit A-24, Schedule N3 Revised, Line 286 for additional project details.

(3) Contact Center Application Health

The Company is seeking recovery for $3.0 million in the Contact Center Application Health project over the 26 months ending February 29, 2028, and the

Line No.

1 historical spend of $1.4 million in 2025 as shown on line 9 of Exhibit A-12,
2 Schedule B5.7.2.
3
4 This investment supports the continued reliability, security, and performance of the
5 Company's NICE cloud-based telephony platform, which underpins daily Contact
6 Center operations and supports thousands of customer interactions each day. The
7 platform is a critical component of DTE's customer service infrastructure and
8 enables timely handling of customer inquiries, service requests, and outage-related
9 communications.
10
11 Although NICE is a cloud-hosted solution, ongoing investment is required to
12 maintain proper configuration, integration, and alignment with DTE's operational
13 and cybersecurity requirements. The platform relies on DTE's internal network,
14 authentication, and back-end customer systems, requiring coordinated updates to
15 ensure compatibility, performance, and data integrity as those systems evolve.
16 This investment funds the work necessary to sustain the telephony environment,
17 including platform upgrades, vulnerability remediation, configuration updates, and
18 required hardware and environmental changes. It also supports ongoing
19 adjustments needed to accommodate business process changes, system
20 integrations, and vendor-provided software releases.
21
22 Sustaining this investment ensures that DTE Electric can maintain a secure, current,
23 and reliable telephony environment. It reduces the risk of service interruptions,
24 supports compliance with cybersecurity standards, and enables the Contact Center
25 to continue meeting customer expectations for responsive and dependable service.

Line No.

1 Additional project details are provided in Exhibit A-24, Schedule N3 Revised,
2 Lines 287 -290 for additional project details.
3
4 (4) Customer Insight Platform Application Health
5 The Company is seeking recovery for $3.9 million in the Customer Insight Platform
6 Application (CIPA) Health project over the 26 months ending February 29, 2028,
7 as shown on line 21 of Exhibit A-12, Schedule B5.7.2.
8
9 This Investment supports the ongoing operation, maintenance, and security of
10 DTE's customer-facing digital platforms, including the DTE Insight mobile
11 application, Energy Bridge devices, and the associated cloud-based infrastructure
12 provided by Powerley.
13
14 The scope of the CIPA Health project includes required technology lifecycle
15 support to ensure continued platform functionality. Regular updates are necessary
16 to maintain compatibility with frequent iOS and Android operating system changes.
17 Without these updates, customers may lose access to real-time energy usage data
18 and digital self-service features.
19
20 The project scope also includes ongoing security and reliability management. These
21 platforms require continuous updates to mitigate cybersecurity vulnerabilities and
22 to remain aligned with applicable utility cybersecurity standards. Powerley
23 provides this ongoing security management, including monitoring and patching
24 activities, to support secure and reliable platform operations.
25

Line No.

1 In addition, the scope includes firmware maintenance for Energy Bridge devices.
2 Energy Bridges must remain compatible with advanced metering infrastructure
3 ("AMI") meters, communication protocols, and smart home devices. Regular
4 firmware updates are required to ensure accurate readings, stable connectivity, and
5 consistent performance across deployed devices.
6
7 As the Commission recognized in Case No. U-21860, the CIPA Health project
8 functions as the backbone for multiple customer-facing tools that provide real-time
9 energy usage information, billing awareness, and self-service capabilities. These
10 platforms support customer and operational outcomes, including real-time energy
11 awareness, bill management and budgeting, participation in load shifting and
12 demand response programs, reduced customer billing confusion, and reduced
13 contact center call volume.
14
15 Customer engagement with these platforms has continued since the Commission's
16 prior approval. The DTE Insight mobile application has been downloaded by
17 hundreds of thousands of customers, with tens of thousands of users engaging on a
18 monthly basis, and more than 80,000 Energy Bridge devices deployed. Customers
19 who use these tools rely on them for real-time energy insights, billing clarity, and
20 self-service access, particularly during periods of higher usage or billing variability.
21 The value of these platforms is not solely dependent on total customer participation.
22 Even when engagement is concentrated among a subset of customers, the platforms
23 deliver customer service and operational benefits by enabling self-resolution of
24 common usage and billing questions. These benefits extend beyond individual

Line No.

users by contributing to reduced customer contact center demand and improved customer satisfaction.

Powerley provides comprehensive support for the CIPA ecosystem, including application and firmware maintenance, cybersecurity updates, cloud hosting, and technical operations. Ongoing investment is necessary to maintain compatibility with mobile operating system updates, evolving cybersecurity requirements, and cloud infrastructure standards. The Energy Bridge devices similarly require continuous firmware updates to ensure accurate data and reliable functionality.

The Company reports a variance of $2.5 million less over 24 months ending December 31, 2026 than that approved for recovery per Case No. U-21860 Final Order, as software license costs related to Bill Management and DTE Insight were addressed via O&M and not Capital. Additional project details are provided in Exhibit A-24, Schedule N3 Revised, Lines 291-293 for additional project details.

Q89. How does customer use of the Insight App, Energy Bridge, and related platforms translate into measurable operational benefits, such as reduced billing inquiries or increased self-service resolution, beyond simple download or enrollment metrics?

A89. Customer use of the Insight App, Energy Bridge, and related digital platforms delivers measurable operational benefits by reducing avoidable customer contacts, improving self-service resolution, and lowering the Company's overall cost to serve. These benefits are realized through active customer use of specific platform capabilities, not through application downloads or enrollments alone. Billing

Line No.

1 inquiries and high-bill concerns are among the most frequent drivers of customer
2 contacts. The Insight App and Energy Bridge reduce these contacts by providing
3 customers with timely, actionable usage information during the billing cycle,
4 including near real-time or interval consumption data, historical comparisons, and
5 proactive usage notifications.
6
7 When customers can see how usage is accumulating, understand the drivers of
8 increased consumption, and receive alerts when usage is trending higher than
9 normal, many billing questions are resolved before a bill is issued. This pre-emptive
10 visibility reduces the need for customers to contact the Company after receiving a
11 higher-than-expected bill, thereby lowering inbound call volume associated with
12 billing and usage questions. The platform increases self-service resolution by
13 enabling customers to independently answer common questions that historically
14 required live agent assistance, such as why usage increased, how current usage
15 compares to prior periods, or how a rate structure affects monthly charges.
16
17 Through in-app tools such as usage trend views, budgeting and goal-setting
18 features, appliance or behavior-level insights, and rate-plan context, customers are
19 able to self-diagnose usage changes and take corrective action without initiating
20 contact with a customer service representative. As a result, a higher share of
21 customer issues is resolved through digital self-service, which improves
22 first-contact resolution and reduces repeat contacts for the same underlying
23 concern. Also, this platform reduces overall cost to serve by shifting customer
24 interactions from agent-assisted channels to digital self-service and proactive
25 communications.

Line No.

1

2 **Q90. What operational, cybersecurity, or customer service risks would DTE**
3 **Electric face if ongoing vendor maintenance, cloud services, and platform**
4 **upgrades supported by the CIPA health project were deferred or**
5 **discontinued?**

6 A90. Deferring maintenance or upgrades would increase the risk of system degradation,
7 security vulnerabilities, and loss of functionality, which would directly affect
8 customers who rely on these platforms. Replacing or re-platforming the existing
9 systems would introduce significant cost, complexity, and operational risk.
10 Continued investment in the existing platforms therefore represents the lowest-risk
11 and most cost-effective approach.

12

13 (5) Customer Notifications Application Health

14 The Company is seeking recovery for $3.2 million in the Customer Notifications
15 Application Health project over the 26 months ending February 28, 2028 and a
16 historical spend of $1.3 million in 2025, as shown on line 10 of Exhibit A-12,
17 Schedule B5.7.2.

18

19 The Company's enterprise Notification Platform supports more than 165,000
20 customer messages each day across SMS, email, and voice channels, with volumes
21 exceeding 1,000,000 notifications per day during major storm events. In total, the
22 platform delivers roughly 60 million notifications annually, making it a
23 mission-critical component of customer communication and operational readiness.
24 This initiative provides the ongoing maintenance, performance optimization, and
25 functional enhancements required to ensure the platform remains reliable, scalable,

Line No.

1 and responsive to evolving business needs. Sustained investment enables the
2 Company to address year-round bug fixes, tune system performance to handle peak
3 volumes, and deliver new or updated notification campaigns across all channels. It
4 also supports the development of enhanced reporting capabilities, such as improved
5 dashboards, customer journey insights, and automated alerts, which strengthen
6 visibility into system performance and help teams quickly identify and resolve
7 issues. See Exhibit A-24, Schedule N3 Revised, Lines 294-297 for additional
8 project details.
9
10 (6) Customer Relationship and Billing (CR&B) Program
11 The Company is seeking recovery for $13.4 million in the Customer Relationship
12 and Billing Program project over the 26 months ending February 29, 2028, and the
13 historical spend of $6.4 million in 2025, as shown on line 11 of Exhibit A-12,
14 Schedule B5.7.2.
15
16 The CR&B production environment needs to be regularly maintained to ensure the
17 health, compliance, and strategic alignment of the SAP CR&B Platform while
18 providing a high level of availability with accurate data to meet the business needs
19 of the Customer Service, Billing and Metering, Distribution Operations, Energy
20 Optimization, Treasury, Controller, Gas Operations, and Electric and Gas Sales and
21 Marketing organizations and benefit customers with efficient and cost effective
22 service. The scope of this investment spans all major customer lifecycle functions,
23 move-In/Move-Out, Billing, Payments, Collections, Metering, Service Orders,
24 Outage/Leak response, digital channels, and cross-system integrations, ensuring
25 stable, compliant, and customer-centric operations across the enterprise. To sustain

Line No.

1 and continuously improve CR&B applications, the initiative implements a
2 structured product support model that includes monthly deployments, ongoing
3 defect management, annual regression cycles, and performance testing to ensure
4 scalability during peak events such as storms, extreme weather, and billing cycles.
5 This disciplined approach maintains system stability, reduces technical debt, and
6 ensures rapid adaptation to evolving business and regulatory requirements.
7
8 Collectively, the scope strengthens the end-to-end customer experience, enhances
9 operational reliability for both electric and gas services, and ensures the enterprise
10 remains compliant, resilient, and capable of supporting future modernization
11 efforts.
12
13 The Company reports a variance of $7.8 million more over 24 months ending
14 December 31, 2026 than that approved for recovery per Case No. U-21860 Final
15 Order. Of this amount, $6.4 million is due to the Commission's full project
16 disallowance in 2026. As discussed further below, the remaining $1.4 million
17 reflects incremental costs incurred in 2025 associated with additional scope that
18 was absorbed to support incremental improvements and minor enhancements.
19 These enhancements were prioritized to address evolving business needs related to
20 Field Service Order functionality, electric outage management, and gas leak
21 response capabilities. Additional project details are provided in Exhibit A-24,
22 Schedule N3 Revised, Lines 298-301 for additional project details.
23

Line No.

1 **Q91. The Commission in its Final Order in Case No. U-21860 found that the**
2 **increase in CR&B Platform costs from Case No. U-21534 was unsupported.**
3 **Can you explain why costs have increased?**
4 A91. The increase in CR&B Platform costs since Case No. U-21534 and Case No. U-
5 21860 was not the result of new or unplanned spending above what the Company
6 had previously represented. Rather, it was a direct result of the consolidation of
7 several previously separate efforts into the CR&B Program. As explained in prior
8 testimony of Witness Ambrose in Case No. U-21860, beginning in 2024, as part of
9 the Company's ongoing vendor negotiations and in alignment with its strategic
10 vision of cost optimization, the scope and associated costs of the Automated
11 Application Monitoring Health, Closed Loop COCL Application Health, Customer
12 Information Technology Configuration Management, and Customer Legacy
13 Application Health projects were integrated into the CR&B Program. These were
14 not new expenditures created. The integration of these additional efforts into the
15 CR&B Program in U-21860 is what drove the variance the Commission observed.
16
17 **Q92. What specific operational issues would arise if the CR&B system were not**
18 **adequately sustained, including impacts to billing accuracy, service order**
19 **processing, outage, and regulatory compliance?**
20 A92. Inadequate sustainment of the CR&B Platform would create significant operational
21 risks across several critical functions, each of which is described below.
22 **Billing Accuracy and Revenue Integrity**: The SAP IS-U system contains complex
23 billing logic aligned with approved tariffs, riders, surcharges, and regulatory rules.
24 Without proper sustainment, the Company faces increased likelihood of
25 configuration drift, batch failures, and unresolved billing exceptions, which can

1 result in incorrect bill calculations, proration errors, misapplied rates, and higher
2 volumes of rebills and customer disputes. Over time, these issues erode customer
3 trust, drive up call center volumes, introduce revenue leakage risk, and invite
4 additional regulatory scrutiny related to tariff adherence.

5 **Meter-to-Cash Processing Reliability:** The platform relies on stable integrations
6 with upstream and downstream systems including AMI/MDMS, payment
7 processors, bill presentment vendors, and enterprise financial systems. Reduced
8 sustainment activities such as interface monitoring, performance tuning, and
9 patching elevate the risk of missed or delayed billing cycles, batch job overruns,
10 processing backlogs, and reconciliation gaps between billing and financial systems,
11 all of which increase operational workload, require manual intervention, and raise
12 the probability of customer bill shock from delayed usage catch-up.

13 **Field Service Execution:** Service orders for moves, connects, disconnects, meter
14 work, and premise activities originate in SAP IS-U and flow to scheduling and
15 dispatch systems. Insufficient sustainment can cause service orders to fail to
16 transmit, duplicate, or become stuck in intermediate states, and completed field
17 work may not properly update customer or billing records. For sensitive activities
18 such as disconnects and reconnects, these failures carry direct risk of customer
19 harm, increased complaints, and regulatory exposure.

20 **Support for Outage Communications and Customer Channels**: Although
21 outage detection and restoration are managed by separate OMS platforms, SAP IS-
22 U serves as a critical source of customer, premise, and contact data used for outage
23 notifications and customer-facing communications. Degraded data accuracy or
24 interface reliability can result in customers being incorrectly associated with outage
25 events, missing or misdirected notifications, and inaccurate identification of

Line No.

1 priority or medically sensitive customers, all of which become highly visible during
2 major outage events.
3 **Regulatory Compliance and Audit Readiness:** SAP IS-U is central to the
4 Company's compliance obligations related to billing, customer protection, record
5 retention, and audit readiness. It maintains historical bills, payment records, service
6 orders, notices, and customer attributes relied upon to respond to complaints,
7 regulatory inquiries, and data requests. Reduced sustainment also increases
8 cybersecurity and privacy risk, as the system requires regular security patching and
9 access control maintenance to protect sensitive customer data.
10 **Business and Customer Impact:** Early indicators of inadequate sustainment —
11 such as increased billing exceptions, payment posting delays, and growing
12 customer contact volumes — if left unaddressed, this will escalate into systemic
13 billing inaccuracies, higher field service costs, degraded outage communications
14 during major events, and increased regulatory scrutiny.
15
16 (7) Digital Channels Application Health
17 The Company is seeking recovery for $3.6 million in the project over the 26 months
18 ending February 29, 2028, and the historical spend of $1.8 million in 2025, as
19 shown on line 12 of Exhibit A-12, Schedule B5.7.2.
20
21 While the Company is investing in transitioning away from aging platforms and
22 has made significant strides in migrating key digital self-service transactions to the
23 Cloud, critical assets such as customer Web login, Billing Web, portions of
24 Payment Web, customer profile settings, and all Web transactions for Commercial
25 and Industrial customers remain on legacy web platforms. Continued investments

Line No.

1 are necessary to maintain these critical assets until they are migrated and can be
2 fully retired. The Digital Channels S3 Application Health project will continue to
3 provide essential sustainment activities and fund minor enhancements to the legacy
4 platform, enabling the Company to maintain key customer transactions during the
5 ongoing transformation (migration to the Cloud).
6 This investment supports development, testing, and project management to deliver
7 monthly software releases for 2025, 2026, 2027 and 2028. The scope of each
8 release is prioritized monthly, with enhancements prioritized based on the
9 following metrics: Digital Engagement Rate, Transaction Completion Rate, Defect
10 reduction. Customer Complaint reduction, System Availability, Planned Outage
11 reduction, Unplanned Outage reduction. Additional project details are provided in
12 Exhibit A-24, Schedule N3 Revised, Lines 302-305 for additional project details.
13
14 (8) Hybris Application Health
15 The Company is seeking recovery for $2.7 million in the Hybris Application Health
16 project over the 24 months ending February 29, 2028, and the historical spend of
17 $2.3 million in 2025 as shown on line 22 of Exhibit A-12, Schedule B5.7.2.
18
19 The Hybris Application Health project is an annual investment that will continue
20 in 2026. Through this project, the Hybris Software Solution, an e-commerce
21 delivery platform, will allow the Company to design and deliver non-metered
22 products (products that do not require a meter for billing purposes, e.g., Surge
23 Protection Program, TreeGuard Assurance, Smart Savers, and Smart Currents) in
24 conjunction with existing metered offerings. These systems require regular
25 production deployments to support daily operations and effective delivery of

Line No.

1 service to customers. The Hybris platform is a software-as-a-service solution from
2 SAP which typically issues quarterly updates. To align with this release cycle, DTE
3 must continually maintain vendor-supported versions of the platform while
4 enhancing its performance and scalability to accommodate new capabilities and
5 functionalities. For instance, the company was previously utilizing a 2005 version
6 of the Hybris platform, which was slated to reach its end-of-life in March 2023
7 according to the vendor. In response, the project successfully upgraded the platform
8 in 2023 to the supported version 2211 of SAP Commerce Cloud and SAP
9 Marketing Cloud.
10
11 The Company reports a variance of $1.0 million more over 24 months ending
12 December 31, 2026 than that approved for recovery per Case No. U-21860 Final
13 Order. Of this amount, $0.4 million is due to disallowances of 10% in 2025 and
14 2026 and the remaining $0.6 million variance is primarily attributable to higher-
15 than-planned expenditures for customer-facing digital platform initiatives in 2025,
16 including the marketing platform migration, enhancements to customer identity and
17 access management, and remediation of platform issues identified through routine
18 patching and maintenance activities. See Exhibit A-24, Schedule N3 Revised, Lines
19 306,307 for additional project details.
20
21 (9) MIGreenPower Program Stabilization
22 The Company is seeking recovery for $1.5 million in this program over the 14
23 months ending February 28, 2027, and has a historical spend of $1.8 million in
24 2025 as shown on line 23 of Exhibit A-12, Schedule B5.7.2.
25

Line No.

1 This project sustains and supports the MIGreenPower applications in production by
2 making necessary changes and updates to the existing SAP applications (CR&B,
3 ISU) to support the renewable business as projects are completed. Annually,
4 Enhance and develop within DTE's current SAP CR&B, SAP BW, SAP Commerce
5 cloud, Emarsys and SAP Analytics cloud Design, develop, test and deploy the new
6 solar park product into the existing C360 billing system, to bill credits/invoices.
7 The Company reports a variance of $0.5 million more in 24 months ending
8 December 31, 2026 as compared to final order U-21860 primarily to 10%
9 disallowance in 2025 and 2026. See Exhibit A-24, Schedule N3 Revised, Lines
10 308-309 for additional project details.
11
12 (10) Outage PPS, WISMO and Outage Map Application Health
13 The Company is seeking recovery for $11.1 million in the Outage PPS, WISMO
14 and Outage Map Application Health project over the 26 months ending February
15 29, 2028, and has a historical spend of $3.4 million in 2025 as shown on line 24 of
16 Exhibit A-12, Schedule B5.7.2.
17
18 The Error Free Communications – Outage Status (EFC) initiative established three
19 critical customer-facing and operational assets—Premise Power Status (PPS),
20 Where-Is-My-Order (WISMO), and the Outage Map—to support DTE's Outage
21 Management and Storm response processes. As these systems now serve as
22 foundational components of the customer experience and storm-readiness
23 ecosystem, ongoing sustainment is essential to ensure uptime, resiliency, and
24 adaptability as DTE advances toward its long-term EFC objectives.
25

Line No.

1 This multiyear effort funds the continuous maintenance and enhancement of the
2 EFC systems, including process improvements, hardware upgrades, defect
3 remediation, and minor functional enhancements. Regular load testing will validate
4 system performance under catastrophic storm conditions—such as scenarios
5 involving one million outages—to ensure reliability during peak events. The
6 project also strengthens integration with key enterprise systems, including AMI,
7 ADMS and CR&B, and optimizes the Outage Map load process to improve speed,
8 accuracy, and customer usability.
9
10 Routine security patching, vulnerability remediation, and cloud maintenance will
11 be performed quarterly or per vendor guidance to prevent unplanned outages. In
12 2025–2026, the initiative consolidates PPS into WISMO and transitions Contact
13 Center usage from CRM to WISMO, reducing latency, improving resiliency, and
14 streamlining customer update workflows. The 2027 scope supports enhancements
15 to outage operations by strengthening the supporting systems that deliver outage
16 information to customers, ensuring continued accuracy, reliability, and timeliness
17 across all customer-facing channels. The 2028 scope centers on sustaining the
18 updated customer status service layer and updating system integrations to support
19 DTE Electric's OMS platform. This work is intended to preserve uninterrupted
20 customer communications and operational continuity during the transition, rather
21 than introduce new customer-facing capabilities.
22
23 This investment ensures that the Company's outage communication ecosystem
24 remains resilient, secure, and aligned with evolving operational requirements while

Line No.

1 maintaining a consistent and reliable customer experience. See Exhibit A-24,
2 Schedule N3 Revised, Lines 310-313 for additional project details.
3
4 **Q93. Have there been update meetings held with Commission Staff regarding the**
5 **Outage PPS, WISMO and Outage Map platform since the biannual meeting**
6 **requirement was established in Case No. U-21534?**
7 A93. Yes. In the Case No. U-21534 order dated January 23, 2025, the Commission
8 directed the Company to hold biannual meetings with Commission Staff to provide
9 detailed status updates on the EFC program. The Company has actively worked to
10 meet and exceed its obligation to meet with Commission Staff on a biannual basis
11 as directed by the Commission. The Company met with Commission Staff three
12 times last calendar year in June, July, and December 2025. The Company is also
13 scheduled to meet three times in 2026, with the most recent meeting held in
14 February 2026. The biannual cadence and any follow-up meetings help ensure that
15 all relevant subject matter and Commission Staff inquiries are covered. During
16 these meetings, the Company provides detailed updates on the status and progress
17 of reaching outage communication long-term objectives and metrics, as well as
18 improvements to the outage communication customer-facing and core systems,
19 including expenditure information and learnings from continuous improvement
20 efforts consistent with the expectations established in the prior proceeding.
21
22 **Q94. How does the requested funding represent the necessary cost of sustaining**
23 **existing outage communication systems and what operational and**
24 **customer-facing impacts would be impacted if those systems were not**
25 **adequately sustained?**

Line No.

A94. The requested funding represents the prudent sustainment of existing outage communication systems—not an expansion of scope or functionality—and reflects the ongoing requirement to maintain and strengthen complex, integrated IT platforms over time. Like all enterprise IT systems, the Error Free Communications ecosystem, including Premise Power Status, WISMO, and the Outage Map, requires continuous support to remain secure, reliable, and aligned with upstream operational changes. For example, as Distribution Operations integrates additional SCADA-verified devices to improve awareness of customer power status, outage communication systems must be continuously updated to consume and appropriately supplement new data sources alongside existing AMI and OMS signals, ensuring customer-facing communications remain aligned with the most complete and verified view of customer power status. Similarly, improvements to OMS restoration modeling and estimate business rules require corresponding updates to estimate communications rules in WISMO. Absent adequate sustainment, these routine operational and system enhancements would introduce misalignment across systems as they evolve and continuously improve customer outage communications, which could result in less consistent, transparent, accurate and timely outage and restoration information provided to customers, increasing customer effort and potential confusion between the information being presented across the channels (e.g., OMS could have a different outage status from WISMO if not properly sustained, which shows up as differences with information shown on the Outage Map), as well as degrading performance.

Q95. Why is the Company's continued investment in outage communication systems reasonable and prudent?

Line No.

A95. The Company's request for continued investment reflects the ongoing capital required to maintain the effectiveness of outage communication systems following their initial implementation. Previously approved investments supported the deployment of core and customer-facing outage communication capabilities. As those systems move from implementation to steady-state operations, continued capital investment is necessary to ensure they remain reliable, accurate, and responsive to evolving system dependencies and customer expectations. Outage communication systems are customer-facing operational platforms that must remain integrated with continuously changing outage management, data, and notification environments. Maintaining their effectiveness requires periodic capital investment to address technology obsolescence, system interoperability, cybersecurity, and performance under complex outage conditions. Absent such investment, the quality and reliability of outage communications would naturally diminish over time.

Accordingly, the Company's request is focused on preserving and sustaining the functionality and customer benefits of previously implemented outage communication capabilities, rather than expanding or duplicating their original scope. This investment is intended to ensure that customers continue to receive timely, accurate, and dependable outage information consistent with the systems' approved purpose.

Q96. What objective performance indicators and customer experience measures demonstrate that continued investment is necessary to maintain the

Line No.

effectiveness of outage communication systems after implementation, rather than those systems continuing to perform without ongoing support?

A96. The Company remains committed to improving the quality of the information provided to customers during an outage as measured by four key outage communication metrics established during the Error Free Communications Initiative. (1) Customer Premise Power Status, which includes real-time power status at the customer's premise (i.e., home or business), (2) Power Restoration Accuracy and Timeliness (i.e., confirmation that power has been restored), (3) First Estimate Accuracy (i.e., accuracy with which the Company provides customers with their first estimated time of restoration), and (4) Outage Delivery Notification, successful outage notification delivery (i.e., percentage of customers who receive required outage notifications).

Our progress and performance toward our long-term outage communication objectives and goals are represented by these four key outage communication metrics and are shown in the table below. Sustained investment preserves and improves outage accuracy, timeliness, and communication delivery—outcomes that require ongoing support to maintain and are not self-sustaining after they are deployed.

Table 9 Improvement in Key Outage Communication Metrics

Performance Metric	2023	2024	2025	Long-Term Goal
1. Customer Premise Power Status (PPS)	41%	52%	54%	70%
2. Restoration Communication	35%	60%	76%	90%

Line No.

1

Performance Metric	2023	2024	2025	Long-Term Goal
Timeliness (within 30 minutes)				
3a. First Estimate Accuracy – Non-storm	43%	63%	79%	95%
3b. First Estimate Accuracy – Storm	47%	65%	90%	95%
4. Outage Delivery Notification	88%	97%	99%	99%

2 (11) SAP BTP Cloud Applications Health

3 The Company is seeking recovery for $1.2 million in the SAP BTP Cloud
4 Applications Health project over the 26 months ending February 29, 2028 as shown
5 on line 14 of Exhibit A-12, Schedule B5.7.2.
6
7 This investment supports the sustainment of the SAP BTP cloud platform used to
8 enable customer self-service products and business services. SAP BTP is a
9 software-as-a-service platform that requires customers to remain on supported
10 vendor versions, with releases issued periodically by SAP. This investment
11 supports the application, testing, and deployment of required platform updates in
12 alignment with the vendor release schedule, as well as services necessary to meet
13 required service-level performance. The scope for 2027 and 2028 includes platform
14 enhancements and feature updates, along with support for transitioning select
15 on-premises services to cloud-based BTP operations. This investment enables the
16 Company to maintain platform compatibility and support deployment of
17 business-driven initiatives reliant on the SAP BTP environment. See Exhibit A-24,
18 Schedule N3 Revised, Lines 315-316 for additional project details.
19
20 (12) SAP CX Cloud Applications Health

Line No.

1 The Company is seeking recovery for $2.3 million in the SAP CX Cloud
2 Applications Health project (previously under Hybris Application health, SAP
3 rebranded the Hybris portfolio under SAP Customer Experience (SAP CX) over
4 the 26 months ending February 29, 2028 as shown on line 15 of Exhibit A-12,
5 Schedule B5.7.2.
6 This investment supports sustainment of the SAP Customer Experience (CX) cloud
7 platform, which enables the delivery of customer self-service products and
8 business-driven initiatives. SAP CX is a software-as-a-service platform that
9 requires customers to remain on supported vendor versions, with new releases
10 issued periodically by SAP. The requested funding supports the capacity and
11 services necessary to apply, test, and deploy SAP-provided releases to the SAP CX
12 cloud platform during 2027 and 2028, in alignment with the vendor release
13 schedule. These activities ensure continued platform compatibility, performance,
14 and service-level compliance.
15
16 This investment also supports the labor and vendor services required to implement
17 required upgrades and enhancements and to meet applicable service-level
18 expectations under the SAP CX cloud services agreement. Maintaining the
19 platform on supported versions enables the Company to deploy new business
20 initiatives that rely on the SAP CX environment. See Exhibit A-24, Schedule N3
21 Revised lines 317-318 for additional project details.
22
23 (13) Self Service Mobile Channel App Application Health
24 The Company is seeking recovery for $2.4 million in the Self Service Mobile
25 Channel Application Health project over the 26 months ending February 29, 2028,

Line No.

and the historical spend of $1.0 million in 2025, as shown on line 16 of Exhibit A-12, Schedule B5.7.2.

This investment supports enhancements to the Company's mobile applications to ensure they continue to provide secure, reliable, and effective digital services to customers. The Company's iOS and Android mobile applications serve as key customer self-service and communication channels, including for outage information and service-related transactions. The scope of this work supports the development, testing, and delivery of regular mobile application updates during the 2025–2028 period. Enhancements are prioritized based on customer engagement, transaction completion, system performance, defect reduction, and improvements in outage communication and customer experience. This investment supports targeted application updates needed to address evolving technical requirements, customer feedback, and performance metrics. This investment ensures the Company's mobile applications remain responsive, resilient, and aligned with customer expectations and operational requirements, while continuing to serve as an essential digital channel for customer interaction and outage communications. See Exhibit A-24, Schedule N3 Revised, lines 319 - 322 for additional project details.

(14) Supporting Capabilities Test Data and Test Data Management

The Company is seeking recovery for $1.1 million in the Supporting Capabilities Test Data and Test Data Management project over the 29 months ending February 29, 2028, and has a historical spend of $0.7 million in 2025, as shown on line 17 of Exhibit A-12, Schedule B5.7.2.

Line No.

1

2 This multi-year initiative supports the Company's enterprise testing ecosystem by
3 expanding automated testing and performance testing capabilities through 2026–
4 2027 and sustaining a stable, scalable quality engineering platform through 2028.
5 The investment is intended to support increasing system complexity, SAP cloud
6 initiatives, and growing customer-facing digital demands while maintaining system
7 reliability and operational readiness.

8

9 During 2026 and 2027, the focus is on expanding automated regression testing and
10 strengthening performance testing capacity to validate system behavior under peak
11 usage and outage conditions. These activities improve release quality, reduce
12 manual testing effort, and help ensure systems perform reliably during high-impact
13 events. The 2028 scope centers on sustaining the enterprise testing platform to
14 ensure continued coverage, governance, and performance validation as applications
15 and integrations evolve. Collectively, this investment enables consistent regression
16 coverage, performance readiness, and a resilient testing environment to support the
17 Company's critical systems through 2028.

18

19 The Company reports a variance of $0.3 million more over 24 months ending
20 December 31, 2026 than that approved for recovery per Case No. U-21860 Final
21 Order, due to $0.1 million of disallowance by Commission per final order U-21860
22 and the remaining $0.2 million due to reallocation of expenses between this project
23 and the Powerley Customer Platform Application Health project.
24 See Exhibit A-24, Schedule N3 Revised, lines 323-326 for additional project
25 details.

Line No.

1

2 (15) Web Transactions Application Health

3 The Company is seeking recovery for $10.8 million in the Web Transactions
4 Application Health project over the 26 months ending February 29, 2028, and has
5 a historical spend of $4.1 million in 2025, as shown on line 18 of Exhibit A-12,
6 Schedule B5.7.2.

7 Over the past several years, the Company has made significant progress in
8 migrating and transforming customer self-service digital transactions from legacy
9 web platforms to the Cloud. Applications now hosted in the Cloud include the
10 Outage Center, Police and Fire Outage Reporting, Municipality Outage Reporting,
11 Payments, Customer Move-In / Move-Out / Transfer, MIMO Order Tracker,
12 Collections Payment Agreement, Collections Payment Extension, Collections
13 Reconnect, Web Registration, and Customer Address Search. The Web remains the
14 primary channel for customer self-service; in 2024, 29% of all interactions were
15 completed on the Web. Additionally, the adoption of self-service has improved
16 significantly for transactions migrated to the Cloud; in 2024, 40% of Outage
17 transactions were completed on the Web, along with 20% of MIMO transactions,
18 20% of Collection transactions, and 10% of Payment transactions.

19

20 Given the Web's role as the primary customer channel, this project supports
21 essential sustainment activities to ensure that Web-based transactions in the Cloud
22 remain functional, secure, and aligned with business needs. These activities include
23 operational monitoring, bug fixes, performance optimization, security updates, and
24 minor enhancements. These efforts aim to maintain key customer transactions and
25 improve digital self-service metrics. These enhancements will be developed using

Line No.

1 bi-weekly sprints, with regular releases throughout 2025 and 2026. Specific work
2 items will be identified and prioritized for each sprint based on customer value,
3 security, and technical criticality. Key metrics for prioritization include the Digital
4 Engagement Rate (which supports call volume reduction), Transaction Completion
5 Rate, System Availability, Complaint Reduction, Vulnerability Count, Planned
6 Outage Reduction, and Unplanned Outage Reduction. See Exhibit A-24, Schedule
7 N3 Revised, Lines 327-330 for additional project details.
8
9 3. Return-to-Health
10 **Q97. Please explain the Customer Service investments in the 'Return-to-Health'**
11 **category.**
12 A97. The Company is seeking recovery for $21.6 million in the Return-to-Health
13 category over the 26 months ending February 29, 2028 and the historical spend of
14 $3.9 million in 2025, as shown in lines 25 through 30 of the Capital Expenditures
15 Exhibit A-12, Schedule B5.7.2. These investments are described below.
16
17 (1) C&I Portal Migration
18 The Company is seeking recovery for $4.9 million in the C&I Portal Migration
19 project over the 26 months ending February 29, 2028, as shown on line 25 of
20 Exhibit A-12, Schedule B5.7.2.
21
22 The investment aims to complete the migration of DTE Energy website from on-
23 premises servers to the cloud (AWS) by migrating the Commercial and Industrial
24 (C&I) Portal and the Landlord Utility Management (LUM) Portal from on prem
25 WebSphere infrastructure to the Cloud. This migration will enhance the reliability

Line No.

1 and efficiency of these applications, which are accessed frequently by commercial
2 and landlord customers. By moving to the Cloud, DTE can mitigate risks associated
3 with the current unsupported technology platform, improve customer satisfaction,
4 and reduce call volumes. The cloud platform will also enable the development of
5 additional self-service functionalities, providing a more comprehensive and
6 personalized customer experience. Employees will benefit from agile practices,
7 allowing for more efficient monitoring, operation, and enhancement of web assets.
8 See Exhibit A-24, Schedule N3 Revised, Lines 331-332 for additional project
9 details.
10
11 (2) Digital Channels Transformation Program
12 The Company is seeking recovery for $6.5 million in the Digital Channel
13 Transformation program over the 26 months ending February 29, 2028 and the
14 historical spend of $2.9 million in 12 months ending December 31, 2025, as shown
15 on line 26 in Exhibit A-12, Schedule B5.7.2.
16
17 This multi-year initiative modernizes the Company's customer-facing digital
18 architecture by consolidating applications, strengthening security, and re-
19 platforming key customer content and transactions. The work is structured to
20 progressively migrate existing functionality to a modern, scalable platform while
21 preserving current customer capabilities.
22
23 In 2025, the scope converts existing standalone payments and outage applications
24 into modular web components integrated within the Company's enterprise
25 architecture. In 2026, the initiative redesigns customer registration and transitions

Line No.

customer authentication and transactions to the Company's CIAM platform, enabling enhanced security features such as multi-factor authentication and modern credential options.

The 2027–2028 scope re-platforms web content, forms, and remaining customer transactions to a modern content and experience platform. This includes migration of existing payment, outage reporting, status inquiry, and document submission functionality to the new architecture. These efforts are intended to streamline the customer experience, improve security, and support long-term digital scalability without expanding customer-facing scope. See Exhibit A-24, Schedule N3 Revised, lines 333- 336 for additional project details.

(3) Migrate SAP CR&B to SAP S/4 HANA

The Company is seeking recovery for $2.4 million in the Migrate SAP CR&B to SAP S/4 HANA over the 26 months ending February 29, 2028, as shown on line 27 in Exhibit A-12, Schedule B5.7.2.

This investment supports the migration of the Company's SAP Customer Relationship and Billing (CR&B) system to SAP S/4HANA. The migration is intended to improve system performance, streamline customer and billing processes, and ensure continued vendor support by transitioning from SAP ECC ahead of SAP's 2027 end of support deadline. The investment supports conversion of existing data, configurations, and custom functionality to the SAP S/4HANA platform, along with validation to ensure data integrity, functional continuity, and minimal disruption to operations. Migration also enables simplified and more

Line No.

1 automated business processes, supporting improved efficiency and operational
2 reliability. Testing and validation activities ensure that the migrated system meets
3 business and regulatory requirements, while training and change management
4 activities support effective adoption by users. Collectively, this investment
5 positions the Company to maintain a supported, modern billing platform capable of
6 meeting future operational and customer service needs. See Exhibit A-24, Schedule
7 N3 Revised, Line 337 for additional project details.
8
9 (4) Migrate SAP Marketing Cloud to SAP EMARSYS
10 The Company is seeking recovery for $1.0 million in the Migrate SAP Marketing
11 cloud to SAP EMARSYS project over the 12 months ending December 31, 2025,
12 as shown on line 28 in Exhibit A-12, Schedule B5.7.2.
13
14 DTE is undertaking a strategic migration from SAP Marketing Cloud to SAP
15 Emarsys in alignment with the vendor's product roadmap and the planned
16 end-of-support in 2026. This transition ensures continuity of marketing operations
17 while enabling the organization to leverage a more advanced, integrated, and
18 future-ready marketing platform.
19
20 The initiative includes establishing and configuring a new SAP Emarsys tenant and
21 integrating it with key on-premise business systems. Because Emarsys offers
22 significantly enhanced marketing capabilities, existing marketing-to-sales
23 processes will be redesigned to take advantage of improved personalization,
24 omnichannel engagement, and stronger traceability of marketing spend.

Line No.

1 A major component of this transformation is the consolidation of marketing tools
2 into a single, integrated platform supported by centralized data governance.
3 Implementing SAP Customer Data Platform (CDP) will provide a unified
4 360-degree customer view, enabling better insights, consistent policy enforcement,
5 and more effective targeting. To streamline operations and reduce costs, the
6 initiative will scale back certain scope items by leveraging Emarsys automation for
7 repetitive tasks such as email campaigns, social media posting, and data analysis.
8 This consolidation reduces duplication of effort and lowers operational overhead.
9 Additionally, Emarsys' built-in AI-driven predictive analytics will allow DTE to
10 deliver more focused, relevant marketing campaigns and personalize
11 communications across multiple channels including SMS, voice, and social
12 platforms. Overall, this migration positions DTE to modernize its marketing
13 ecosystem, improve customer engagement, enhance operational efficiency, and
14 support long-term digital marketing growth.
15
16 The Company reports a variance of $1.0 million less in 24-month period ending
17 December 31, 2026, as compared to the final order in Case No. U21860 due to
18 reduction in project scope implemented to align with other prioritized initiatives.
19 The scope reduction defers certain advanced marketing and personalization
20 capabilities, including centralized campaign cost optimization, predictive analytics
21 for targeted outreach, and multichannel personalized communications. These
22 elements were deferred because the underlying platform requires sufficient
23 operational data and stabilization before advanced automation and analytics can be
24 effectively implemented. The revised approach prioritizes stabilizing the platform
25 and enabling use by multiple business units through standard, out-of-the-box

Line No.

1 reports and dashboards. After a period of operational use and data maturity, the
2 Company will reassess opportunities to introduce additional automation, analysis,
3 and reporting enhancements as appropriate. See Exhibit A-24, Schedule N3
4 Revised, line 338 for additional project details.
5
6 (5) SAP Commerce B2C storefront migration
7 The Company is seeking recovery for $2.6 million in the SAP Commerce B2C
8 storefront Migration over the 26 months ending February 29, 2028, as shown on
9 line 29 in Exhibit A-12, Schedule B5.7.2.
10
11 This project involves the migration of DTE Electric's SAP Commerce B2C
12 storefront to a composable storefront (Spartacus) and integration of the storefront
13 with Adobe Experience Manager (AEM) as the new content management system
14 (CMS). Currently, the SAP Commerce cloud platform is used by customers to
15 purchase or subscribe to DTE Electric products and services. The existing platform
16 (Accelerator UI) will be unsupported by Q1 2027, necessitating an update to the
17 composable storefront. Migration offers several benefits, including increased
18 flexibility to make changes to products and services, reduced costs and complexity
19 by unifying B2B and B2C storefronts, faster deployment of new products and
20 services, and enhanced content management with AEM, which reduces design and
21 implementation time. The project will be carried out in phases: first, migrating the
22 SAP Commerce B2C storefront to Spartacus; and then integrating AEM as the new
23 CMS. Key functionalities and capabilities include a shopping cart experience for
24 B2C customers, collaboration with the experience design team for web content
25 changes, a centralized content repository for customer access to terms and

Line No.

1 conditions and other documents, and security enhancements to eliminate
2 vulnerabilities in the customer self-service channel. This project will streamline
3 operations, reduce costs, and improve the customer experience by leveraging the
4 latest headless commerce technology and integrated content management.
5
6 The Company reports a variance of $2.3 million less in 24-month period ending
7 December 31, 2026, as compared to the final order in Case No. U21860 due to
8 scope deferral to begin in 2027. See Exhibit A-24, Schedule N3 Revised, Line 339
9 for additional project details.
10
11 (6) Web Billing and Profile Management Cloud Migration
12 The Company is seeking recovery for $5.2 million over the 26-month test year
13 ending February 29, 2028, in the Web Billing and Profile Management Cloud
14 Migration project as shown on line 30 in Exhibit A-12, Schedule B5.7.2.
15
16 The 2027-2028 project aims to migrate the DTE Energy website from on-premises
17 servers to the cloud (AWS), focusing on critical web experiences such as the
18 "current bill" page, billing and payment history, billing programs, and profile
19 settings. This migration will enhance the reliability and efficiency of these services,
20 which are accessed frequently by customers. By moving to the Cloud, DTE can
21 mitigate risks associated with the current unsupported technology platform,
22 improve customer satisfaction, and reduce call volumes. The cloud platform will
23 also enable the development of additional self-service functionalities, providing a
24 more comprehensive and personalized customer experience. Employees will

Line No.

1 benefit from agile practices, allowing for more efficient monitoring, operation, and
2 enhancement of web assets.
3
4 The Company reports a variance of $4.5 million less over the 24-month period
5 ending December 31, 2026, compared to the final order in Case No. U-21860, due
6 to the deferral of the project to begin in 2027. See Exhibit A-24, Schedule N3
7 Revised, Lines 340-341 for additional project details.
8
9 4. Discretionary Customer IT Projects
10 **Q98. Which Customer IT projects are included in this section?**
11 A98. This section includes the Enhancement and Strategic categories of Customer IT
12 Portfolio projects, organized as follows: Customer IT Projects that Enhance
13 Customer Interactions and Payment Merchant Fees
14
15 a) Customer IT Projects that Enhance Customer Interactions
16 **Q99. Can you describe the Company's rationale for investing capital in projects**
17 **that will enable "Enhanced Customer Interactions"?**
18 A99. The Company's strategy to enhance customer interactions is simple – improve the
19 customer experience and the effectiveness and efficiency with which the Company
20 manages customer interactions, by prudently investing in capital projects that
21 improve the quality of the data and information provided to customers during these
22 interactions.
23
24 **Q100. Which of the capital projects are you sponsoring in your testimony that are**
25 **intended to "Enhance Customer Interactions"?**

Line No.

1 A100. I will discuss one project in my testimony that is intended to Enhance Customer
2 Interactions, included in Exhibit A-12, Schedule B5.7 i.e. Error Free
3 Communications – Outage Status, Outage PPS, WISMO and Outage Map
4 Enhancements, as shown in Exhibit A-12, Schedule B5.7.2.
5
6 1) Outage PPS, WISMO and Outage Map Enhancements
7 As described in U-21860, the EFC initiative is intended to significantly improve
8 the quality of the information provided to customers during an outage, which
9 includes real-time power status at the customer's premise (i.e., home or business),
10 power restoration accuracy and timeliness (i.e., confirmation that power has been
11 restored), first estimate accuracy (i.e., accuracy with which the Company provides
12 customers with an estimated time of restoration), and successful outage notification
13 delivery (i.e., percentage of customers who receive required outage notifications).
14 In the instant case, the Company is seeking recovery for a historical spend of $0.6
15 million as shown on line 31 of Exhibit A-12, Schedule B5.7.2.
16
17 **Q101. How have the Company's investments in its EFC – Outage Status project**
18 **improved the key EFC metrics and customer Outage experiences?**
19 A101. Below is a summary of the improvements in the EFC metrics and customer Outage
20 experience realized to-date from the Company's EFC – Outage Status investments.
21
22 Customer Premise Power Status (PPS)
23 At the core of outage communications is the ability for the customer's meter to
24 communicate power status to the Company. This capability not only enables the
25 Company to communicate accurate and timely outage and restoration information,
26 but also provides situational awareness regarding the extent of outages and the

Line No.

1 number of customers affected. This allows for a more accurate assessment of the
2 outage and the development of more precise restoration estimates. The Company's
3 EFC investments have improved this metric from 41% in 2023 to 52% in 2024 and
4 54% in 2025 and due to investments made by the Company; the Company expects
5 this metric to further increase to 70% as our long-term goal.
6 Power Restoration Accuracy and Timeliness
7 Prior to the implementation of the EFC initiative, the customer's power status was
8 tied to the job status, which was overall 94% accurate, but with a range between
9 80% to 94% during high impact and storm days. Because the power status was not
10 premise-based, the Company, in error, could communicate to the customer that
11 power was restored when, in fact, the customer was not restored. With the
12 implementation of EFC, where the customer's power status is based on AMI meter
13 data, the Company has consistently achieved a greater than 99% accuracy rate for
14 outage restoration communications.
15
16 However, timeliness of confirming the customer's power status could be delayed
17 with the use of AMI data, so a new metric was developed to ensure timely delivery
18 of restoration communications – Restoration Communication Sent within 30
19 minutes. In 2023, 35% of customers with reported outages who were restored
20 received confirmation of their restoration within 30 minutes, which the Company
21 increased to 60% in 2024, with additional improvements in 2025 to 76% and a long-
22 term goal of 90%.
23
24 **Q102. What complementary opportunities has the Company identified to support**
25 **improvements in Estimated Time to Restoration (ETR)?**

Line No.

1 A102. To support the Company's EFC restoration estimate and timeliness goals and
2 objectives, DTE's data science team has developed a storm Estimated Time to
3 Restoration (ETR) machine learning model to enhance estimate accuracy and
4 speed. This model processes extensive historical data, such as customer outages,
5 locations, weather, and environmental factors, without human intervention. In
6 2025, the Company continued to test the model during storms, achieving an average
7 first estimate accuracy of 90% during storm, and 79% during non-storm events with
8 long-term goals of 95% for both storm and non-storm. To continue to improve the
9 model's accuracy, the Company is continuing to refine the model with additional
10 data features and align it with the Company's restoration priorities. In parallel,
11 DTE's data science team is continuing to develop a machine learning model control
12 panel for storm leaders to manage estimate communications and handle escalations,
13 with a minimum viable product expected this year. This control panel implements
14 a regulated process to verify the accuracy of the machine learning model's output
15 before delivering estimates to customers, providing additional safeguards to ensure
16 the reliability of the model's estimates.
17
18 **Q103. Can you provide an update on recent improvements to customer-facing outage**
19 **communication systems?**
20 A103. Yes, below is an update on recent improvements to the customer-facing outage
21 communication systems.
22
23 ▪ **Customer Service Representative (CSR) Outage Status Project**
24 Prior to this initiative, call center representatives relied on an outdated SAP system
25 to check customer outage status. A new web-based application was implemented

Line No.

1 to align CSR visibility with customer self-service channels, enabling
2 representatives to view the same outage and estimated restoration information
3 available to customers. CSRs gained the ability to drill into customer
4 communications, job details, crew status, and field notes from the Outage
5 Management System (OMS). These enhancements provided a 360-degree view of
6 customer outage history, current outage conditions, and real-time restoration
7 insights from field crews—capabilities that were previously unavailable. By
8 consolidating outage data into a single platform, representatives are now equipped
9 to deliver a more accurate and comprehensive customer experience.
10
11 ▪ **Customer Service Representative (CSR) Outage Reporting Project**
12 Previously, call center representatives relied on an outdated SAP system to report
13 outages on behalf of customers. This project introduced a modern, web-based
14 outage reporting application that aligns call center functionality with customer-
15 facing web and mobile channels. The solution delivers a streamlined, intuitive
16 experience featuring enhanced graphics, augmented call-handling guidance, and
17 map-based decision support, resulting in reduced outage reporting time and
18 improved accuracy. The system also standardized outage reporting for first
19 responders, integrating it into the same web-based platform.
20
21 ▪ **Estimate Windows Project**
22 To improve the quality and clarity of restoration estimates provided to customers,
23 this project transitioned from single-point estimates to a window-based approach.
24 Restoration estimate data from the Outage Management System (OMS) was
25 transformed into time ranges, offering customers a more realistic and reliable

Line No.

restoration timeframe. The initiative required extensive enhancements across core data applications, web, mobile, and IVR channels, notification interfaces, and custom outage map functionality.

- **Single AMI PON Two-Way SMS Project**

To reduce unnecessary and costly truck rolls, a proactive two-way SMS communication solution was implemented. The system automatically triggered customer text messages based on automated meter readings, prompting customers to confirm whether they were experiencing a power interruption. Customer responses were used to automatically create or close outage records in the Outage Management System (OMS). This approach improved outage validation accuracy, reduced unnecessary field dispatches, and generated significant operational cost savings.

- **Invalid Outage Map Data Initiative**

An automated data validation process was developed using a data blending tool to monitor production outage map data. The process analyzed outage polygons and measured the maximum distance between reported premises. Jobs exceeding defined distance thresholds were flagged and written to an output file. Robotic Process Automation (RPA) then generated automated alerts via Microsoft Teams, enabling the support team to quickly review and determine whether system intervention was required. This solution significantly reduced manual effort and proved especially valuable during high-volume storm events.

- **Outage Map Data Cleansing Project**

Line No.

1 An automated data cleansing solution was implemented to identify and prevent
2 invalid source data from displaying on the outage map. Using a data blending tool,
3 the process evaluated equipment hierarchy integrity and validated distances
4 between premises and associated transformers. Premises outside defined thresholds
5 were flagged for review and correction by the support team. Latitude and longitude
6 data was also validated against address data to ensure geographic accuracy. These
7 efforts resulted in a substantial reduction in outage map display issues and
8 improved overall data reliability.
9
10 ▪ **Service Recovery Project (Design)**
11 To improve the customer experience for those customers experiencing 4 or more
12 outages in a calendar year, this project focuses on providing more empathetic, clear,
13 and transparent messaging and call handling to frequent outage customers. In 2025,
14 design work was initiated to revamp customer messaging to include more
15 empathetic language, prioritize restoration of these customers when possible, and
16 provide insights into the reliability projects in their areas that will help reduce or
17 eliminate the root cause of their frequent outages. Planned deployment is in May
18 2026.
19
20 b) Payment Merchant Fee Project
21 **Q104. What is the scope of work funded by the $15 million in capital being allocated**
22 **to the Payment Merchant Fee project?**
23 A104. The $15.0 million in capital included in Exhibit A-12, Schedule B5.7, line 32
24 consists of $5.0 million for the 12 months ended December 31, 2026. Historical
25 spending totaled $9.5 million for the 12 months ended December 31, 2025.

Line No.

1

2 This investment is to support use of a third-party consumer payment provider
3 (Paymentus) to develop the Company's card fee / surcharge solution across all
4 served and self-service channels. The provider has developed a solution that
5 handles credit card fee processing, offers Visa consulting support, and assists with
6 the development of a long-term payment strategy that will ensure seamless bill
7 payment options for customers. The $9.5 million requested for 2025 is consistent
8 with the scope of work described in Electric Case No. U-21860. The $5 million
9 requested in the instant case for 2026 supports the final testing, data migration,
10 cutover activities, deployment, and hyper-care for the Payment Merchant Fee
11 initiative that began in 2025. See Exhibit A-24, Schedule N3 Revised, Lines 343-
12 344 for additional project details.

13

14 **Q105. Did the Company consider alternatives to the use of a third-party consumer**
15 **payment provider, including using its own internal payment platform?**

16 A105. -Yes. The Company evaluated several alternatives, including discontinuing card
17 payments altogether and modifying its existing internal payment platform to assess
18 and process credit and debit card fees. Discontinuing card payments was not
19 pursued because it would have negatively impacted the approximately 1.4 million
20 customers who made at least one credit or debit card payment in 2024. The
21 Company also assessed the scope, cost, implementation complexity, and
22 operational risks associated with enhancing its internal payment platform to support
23 card fee assessment, processing, compliance, and ongoing operations.

24

Line No.

1 Based on this evaluation, the Company determined that leveraging a third-party
2 consumer payment provider represented the most prudent and effective solution. A
3 third-party provider offers specialized, payment-industry capabilities that are not
4 available within the Company's internally supported payment platform without
5 significant additional development, expanded compliance obligations, and
6 increased operational risk. These capabilities include secure card tokenization,
7 PCI-compliant card processing, duplicate-payment prevention, structured dispute
8 and chargeback handling, and integrated settlement and reconciliation. Following
9 that determination, the Company completed a competitive procurement process in
10 2025 and selected Paymentus as its third-party consumer payment provider. The
11 Company subsequently engaged Paymentus and implemented the solution through
12 a phased delivery approach, culminating in production go-live in March 2026.
13 Utilizing a third-party provider allows the Company to deliver required customer
14 payment functionality more efficiently while limiting system complexity, reducing
15 risk, and avoiding the need to materially expand its internal payment processing
16 footprint.
17
18 **Q106. Why did the Company select Paymentus as the third party vendor for this**
19 **project through competitive procurement?**
20 A106. Paymentus natively supports card-brand-compliant fee structures, including flat
21 and percentage-based fees, across all customer payment channels at the point of
22 transaction. This capability does not exist within the Company's current payment
23 environment and would require significant customization and ongoing maintenance
24 to implement internally. The Company's current payment processor, Paymetric, a

Line No.

1 Worldpay company, does not support flat fee implementations, which limits the
2 flexibility of any internally supported fee structure.
3
4 In addition, Paymentus assumes responsibility for transaction-level fee
5 management, financial risk, and ongoing compliance with evolving card-brand and
6 payment network requirements. Under an internally supported model, these
7 responsibilities would remain with the Company and require continuous
8 monitoring and manual intervention.
9
10 Paymentus also provides payment resiliency and operational capabilities that allow
11 customer payments to continue during certain internal system disruptions —
12 capabilities that are not currently available within the Company's payment
13 architecture and would require substantial redesign to replicate internally.
14
15 Accordingly, while the Company previously established the general value of
16 third-party payment solutions in Case No. U-21860, the selection of Paymentus
17 provides specific operational, financial, and compliance capabilities that the
18 Company does not possess today and cannot efficiently achieve through its
19 internally supported payment platform.

20 **Q107. What are the key components of the requested investment?**
21 A107. The core portion of the investment modernizes the Company's payment platform
22 to maintain security, reliability, and regulatory compliance across all payment
23 channels, independent of card fee implementation. This includes sustaining
24 PCI-DSS compliance, improving system resiliency and scalability, modernizing

Line No.

1 integrations with billing and settlement systems, and reducing long-term risk and
2 cost associated with maintaining a legacy payment solution.
3
4 Fee-specific enablement includes limited functionality required only to support
5 customer-elected credit and debit card payments, including accurate fee
6 pass-through, clear customer disclosure and consent, integration with a third-party
7 card processor, and compliance with Visa and Mastercard rules. This scope applies
8 solely to card transactions and does not impact customers using ACH payment
9 options.
10
11 **Q108. Does this investment only benefit customers who elect to pay their bills by**
12 **credit or debit card?**
13 A108. No. The investment includes foundational improvements that are broadly beneficial
14 to all customers, regardless of how they choose to pay. These investments support
15 the security, reliability, and sustainability of the Company's end-to-end payment
16 ecosystem across all channels. Specifically, the investment funds include
17 maintaining PCI DSS security and regulatory compliance to protect customer
18 payment data; modernizing the core payment platform to improve system
19 reliability, resiliency, and scalability across web, mobile, IVR, and assisted
20 payment channels; strengthening integrations between customer-facing payment
21 applications, billing, settlement, and financial reconciliation systems; and reducing
22 long-term operational risk and cost associated with sustaining a fragmented, legacy
23 payment solution. Collectively, these improvements benefit all ratepayers by
24 ensuring secure, reliable, and efficient payment processing regardless of payment
25 method...

Line No.

1

2 **Q109. When does the Company expect to begin charging customers who choose to**
3 **use a debit or credit card a fee / surcharge?**

4 A109. The Company began charging non-residential customers who choose to make card
5 payments a fee / surcharge on March 2, 2026.

6 **Q110. What card fee / surcharge structure is being proposed and how will the**
7 **Company manage merchant fees ahead of the planned 2026 Payment**
8 **Merchant Fees project implementation?**

9 A110. The Company is proposing a per-transaction card fee structure under which
10 residential customers would be charged $2.99 per transaction and commercial
11 customers would be charged $9.99 per transaction for credit and debit card
12 payments. These fees would apply only to customers who elect to use card-based
13 payment methods. Customers will continue to have access to ACH payment
14 options, which do not incur a merchant fee. This approach preserves no-fee
15 payment alternatives while allowing customers the option to use card payments
16 with clear and transparent disclosure of associated fees.

17

18 **E. Projects < $250K**

19 **Q111. What is included in the "Projects less than $250,000" category?**

20 A111. The workpaper titled "IT Projects <$250K" shows spend for projects in IT with
21 estimated spend less than $0.25 million in the projected bridge and test periods.
22 These projects span the Portfolios and are necessary investments to collectively
23 support DTE.

24

Line No.

1 **VII. Historical Spend Variance**

2 **A. 2025 Spend Variance**

3 **Q112. How do the Company's 2025 expenditures on total IT capital projects compare**
4 **to the amount authorized for inclusion in rates in Case No. U-21860?**

5 A112. The Company spent $155 million of capital on IT projects in 2025, which is $13.2
6 million more than the $141.8 million approved by the Commission in Case No. U-
7 21860, as shown in line 17 of Exhibit A-24, Schedule N2.

8

9 **Q113. Where are the reasons for the variance between the 2025 actual capital spend**
10 **versus the spend authorized in Case No. U-21860?**

11 A113. Exhibit A-24, Schedule N2, labeled as 2025 Historical Spend Variance Recovery,
12 shows the comparison for projects greater than $0.5 million with a variance
13 exceeding 20% and where additional recovery is being sought, as indicated in Table
14 10. The table below shows a list of projects that the Company is seeking additional
15 recovery for in 2025 and are also included in Exhibit A-24, Schedule N2.

16

17 **Table 10 Variance Exhibit/Schedule Reference by Project**

Portfolio	Description	Variance Testimony Reference
Customer IT	Hybris Application Health	SBA – 148 - 149
Corporate Applications	Secure 2.0 Act for 401K	SBA – 89-90
Corporate Applications	Warehouse Efficiency	SBA – 103
Plant & Field: DO	System Outage Screen (SOS) Application Health	SBA – 119
Infrastructure & Operations	Palo Alto Capital License Renewal	SBA – 65 - 66
Infrastructure & Operations	Virtual Desktop Infrastructure Asset Health	SBA – –82 - 83
Plant & Field: DO	Field Service Edge (FSE) Replacement - Clicksoft	Table 2: IT Approved Project List, SBA - 33

Line No.

IT FOR IT	IT for IT Application Health	SBA – 37 - 39
Infrastructure & Operations	Collaboration Application Health	SBA – 60 - 61
Infrastructure & Operations	VMWare License Renewal	SBA – 67 - 68
Infrastructure & Operations	Security Infrastructure Growth and EOL	SBA – 80 - 82

1 **B. Other Variance**

2 **Q114. Were there any other projects that had variances that you have not yet**
3 **discussed?**

4 A114. Yes. The projects listed in Table 11 below were not completed in 2025 and are not
5 planned to be completed in 2026, as previously approved and included in Case No.
6 U-21860.

7 **Table 11 Project Variance Reasons**

Project	Reason for Variance
Vendor Onboarding for DTE	As part of the Annual Planning and Prioritization Process enhancement, all investments underwent a thorough reassessment. Following diligent reviews, the Vendor Onboarding for DTE capital investment has been deferred to a future year.
Network Access Control	This project has been suspended, and the scope has been integrated into the Network segmentation Phase (2+) project. Variance is discussed in Ambrose's direct testimony pages SBA – 86 - 87.
Mobile Device Management (MDM)	Variance is due to the dependency on Enterprise Mobility Management (EMM) project as it had technical issues causing this project to pause.
SAP Employee Central Payroll	It was determined that SAP Employee Central Payroll should be implemented with the Compensation, Time Entry and Payroll Implementation project for efficient integration, testing capabilities, and deployments. Please see Ambrose Testimony page 99 and 100 for more details.
Talent System Optimization	This project is currently being rescheduled and upon approval of the confirmed project dates, the request for cost recovery will be re-submitted for approval in a future rate case.
GenOpts-FERC Order 841 Compliance	This project has been postponed to future years due to insufficient customer participation in Electric Storage Resources (ESR). DTE will continue using the manual process until customer volume increases.
Customer Notifications TCPA Compliance	This project is currently being replaced by the Customer Consent and Preference Management project on line 1 of Exhibit A-12, Schedule B5.7.2.

Line
No.

Project	Reason for Variance
MDM Stabilization	This project is currently being rescheduled and upon approval of the confirmed project dates, the request for cost recovery will be re-submitted for approval in a future rate case.
Security Information & Event Management (SIEM) End of Life Replacement	This project has been paused to accommodate other high priority work.
Endpoint Privilege Management	This project scope will be covered under Cloud and Endpoint Security Application Health Project discussed in Ambrose's direct testimony pages SBA 47 - 48
Contact Center Technology Upgrades	This project is now re-prioritized and being rescheduled and upon approval of the confirmed project dates, the request for cost recovery will be re-submitted for approval in a future rate case.
Transform and Modernize PO Architecture	This project is currently being rescheduled and upon approval of the confirmed project dates, the request for cost recovery will be re-submitted for approval in a future rate case.
Smart Customer Mobile (SCM®) – SaaS Cloud License Deployment	This project is currently being rescheduled and upon approval of the confirmed project dates, the request for cost recovery will be re-submitted for approval in a future rate case.
Storm Data Lakehouse	This project is currently being rescheduled and upon approval of the confirmed project dates, the request for cost recovery will be re-submitted for approval in a future rate case.
Modernize Infrastructure automation to align with modern cloud focused Tools	This project is currently being rescheduled and upon approval of the confirmed project dates, the request for cost recovery will be re-submitted for approval in a future rate case.
Cellular Gateway Upgrade	This project is currently being rescheduled and upon approval of the confirmed project dates, the request for cost recovery will be re-submitted for approval in a future rate case.
IT Service Management Tool – Hardware Assets	This project is currently being rescheduled and upon approval of the confirmed project dates, the request for cost recovery will be re-submitted for approval in a future rate case.
DTE Utility Network (UN) Model – Full Implementation	Please refer to Witness Rademacher for additional project details.
Vegetation management re-platform (Clearion Replacement)	Please refer to Witness Rademacher for additional project details in Exhibit A-12, Schedule B5.4 Revised, Page 14, line 37 for 2026-2028
Payment Web Self-Service	This project is currently being rescheduled and upon approval of the confirmed project dates, the request for cost recovery will be re-submitted for approval in a future rate case.
Advanced Analytics AA Use Cases	This project is currently being rescheduled and upon approval of the confirmed project dates, the request for cost recovery will be re-submitted for approval in a future rate case.
Cloud Program Foundation & Automation	This project scope has been removed and re-prioritized to accommodate other high priority projects and may be included in future rate case.
Never Billed Accounts due to Theft/Fraud	This project is currently being rescheduled and upon approval of the confirmed project dates, the request for cost recovery will be re-submitted for approval in a future rate case.

Line No.

Project	Reason for Variance
Network Advanced Metering Infrastructure Support	$134k of actuals included in Exhibit A-12, IT Projects <250K. The remaining actuals are included in Exhibit A-12, Schedule B5.4 Revised, page 13, line 20, along with other projects supported by Witness Rademacher.
Weekly Payroll – Davis Bacon Grant	Due to changes in federal grant funding leading to the project being paused in February 2025 and subsequently cancelled.
Generation Optimization Status Tracker (GOST)	This project is currently being rescheduled and upon approval of the confirmed project dates, the request for cost recovery will be re-submitted for approval in a future rate case.
Contact Center Enablement	This project is currently being rescheduled and upon approval of the confirmed project dates, the request for cost recovery will be re-submitted for approval in a future rate case.

Q115. Are there any common causes in variance from Case No. U-21860?

A115. Yes. At times, the IT Department needs to adjust the scope or schedule of projects to address high-priority items based on emerging and higher priority needs. My explanations of historical spend and changes between investment years provided in the preceding sections reflect this prioritization. The re-sequencing of the scope of an entire project reflects the operational reality of making investments with finite IT resources, and as the Company continues to improve its processes and address the key IT investment drivers of cybersecurity, reliability and resiliency, and affordability (cost effectiveness).

Q116. Does this complete your direct testimony?

A116. Yes, it does.

Line No.	Spend Year	Business Case / Project Name	Investment Category	Shared Asset or Excess Duty (if applicable)	IT Portfolio/Program	Witness (if multiple)	BCDID	Cost Estimate Level (if applicable)	Project Synopsis	Value/Benefit	Alternatives Considered including cloud services	Aligned with cloud computing technology strategy?	Please supply an explanation on cloud computing alignment	Equipment involved and refresh line (if applicable)	Project Start Date with Revisions	Project End Datewith Revision	Expected Total Project Cost (Capital + Investment O&M)	Projected Total IT Capital Cost	Projected Labor Cost (Capital)	Projected Capital Non-Labor Cost Contractor	Projected Capital Non-Labor Cost Materials	Projected Capital Non-Labor Cost Software	Projected Capital Overhead Cost	Projected Total IT O&M Cost	Projected O&M Labor Costs	Projected O&M Non-Labor Costs Contractor	Projected O&M Non-Labor Costs Materials	Projected O&M Non-Labor Costs Software	Projected O&M Overhead & Other Costs	Projected Total IT O&M Cost (Inactive)
1	2025	IT for IT Application Health	Sustainment	Shared	Information Technology for IT	Steve Ambrose	DPMD0001350	Actual	Recommended solutions include: - Perform upgrades to ServiceNow, the IT Services Platform core tool, twice each year to ensure we do not lose support eligibility - Complete technical integrations with DTE applications where ServiceNow will create incidents as necessary - Perform monthly updates to minimize security and technical issues - Prioritize and implement new functionality and features as identified and prioritized by our business partners	**Security**: Minimize security vulnerabilities on included systems, reducing the opportunities for system disruption. Optimize visibility and monitoring of IT business applications and those services, systems, hardware and cloud infrastructure to reduce security concerns proactively. **Employee Value**: DTE Energy Information Technology employees will realize process efficiencies and improved effectiveness. DTE Energy employees that use Information Technology systems will experience reduced times for issue resolution and faster delivery of Information Technology requests that enable them to perform their jobs more efficiently and effectively. Once we don't lose the enhancement information until shortly before it is released. We cannot quantify the realized benefits until we know the content of the upgrade.	Doing nothing will have the following negative impacts: - The systems will not be eligible for support by the vendors. If this were to occur and we experience an issue, we may not be able to resolve it. This would severely degrade information technology's ability to monitor IT systems that are support DTE Energy's delivery of energy to our customers - We will not have access to security patches, introducing vulnerabilities that may be exploited by hackers to access and disrupt DTE Energy's system	Standard market-based and/or commoditized non-core energy workload - deploy in commercial cloud	ServiceNow is a public cloud solution in alignment with the cloud computing strategy.	Yes	1/9/2023	12/31/2025	$ 2,580,996.54	$ 2,312,542.47	$ 327,653.35	$ 1,964,893.24	$ 7,799.69		$ 412,218.28	$ 268,454.87	$ 180,133.75	$ 93,189.12	$ 14,709.32	$ 421.89		$ 225,598.28
2	2026	IT for IT Application Health	Sustainment	Shared	Information Technology for IT	Steve Ambrose	DPMD0002354	Level 3	Recommended solutions include: - Perform upgrades to ServiceNow, the IT Services Platform core tool, twice each year to ensure we do not lose support eligibility - Complete technical integrations with DTE applications where ServiceNow will create incidents as necessary - Perform monthly updates to minimize security and technical issues - Prioritize and implement new functionality and features as identified and prioritized by our business partners	**Security**: Minimize security vulnerabilities on included systems, reducing the opportunities for system disruption. Optimize visibility and monitoring of IT business applications and those services, systems, hardware and cloud infrastructure to reduce security concerns proactively. **Employee Value**: DTE Energy Information Technology employees will realize process efficiencies and improved effectiveness. DTE Energy employees that use Information Technology systems will experience reduced times for issue resolution and faster delivery of Information Technology requests that enable them to perform their jobs more efficiently and effectively. Once we don't lose the enhancement information until shortly before it is released. We cannot quantify the realized benefits until we know the content of the upgrade.	Doing nothing will have the following negative impacts: - The systems will not be eligible for support by the vendors. If this were to occur and we experience an issue, we may not be able to resolve it. This would severely degrade information technology's ability to monitor IT systems that are support DTE Energy's delivery of energy to our customers - We will not have access to security patches, introducing vulnerabilities that may be exploited by hackers to access and disrupt DTE Energy's system	Standard market-based and/or commoditized non-core energy workload - deploy in commercial cloud	ServiceNow is a public cloud solution in alignment with the cloud computing strategy.	No	1/2/2026	12/31/2026	$ 2,769,542.84	$ 2,499,991.00	$ 459,899.00	$ 1,985,410.00			$ 384,682.00	$ 269,551.84	$ 250,351.84	$ 109,500.00				$ 280,333.83
3	2027	IT for IT Application Health	Sustainment	Shared	Information Technology for IT	Steve Ambrose	DPMD0004245	Level 3	Recommended solutions include: - Perform upgrades to ServiceNow twice a year, the IT Services Platform core tool, twice each year to ensure we do not lose support eligibility - Complete technical integrations with DTE applications where ServiceNow will create incidents as necessary - Perform monthly updates to minimize security and technical issues - Prioritize and implement new functionality and features as identified and prioritized by our business partners	**Security**: Minimize security vulnerabilities on included systems, reducing the opportunities for system disruption. Optimize visibility and monitoring of IT business applications and those services, systems, hardware and cloud infrastructure to reduce security concerns proactively. **Employee Value**: DTE Energy Information Technology employees will realize process efficiencies and improved effectiveness. DTE Energy employees that use Information Technology systems will experience reduced times for issue resolution and faster delivery of Information Technology requests that enable them to perform their jobs more efficiently and effectively. Once we don't lose the enhancement information until shortly before it is released. We cannot quantify the realized benefits until we know the content of the upgrade.	Doing nothing will have the following negative impacts: - The systems will not be eligible for support by the vendors. If this were to occur and we experience an issue, we may not be able to resolve it. This would severely degrade information technology's ability to monitor IT systems that are support DTE Energy's delivery of energy to our customers - We will not have access to security patches, introducing vulnerabilities that may be exploited by hackers to access and disrupt DTE Energy's system	Standard market-based and/or commoditized non-core energy workload - deploy in commercial cloud	ServiceNow is a public cloud solution in alignment with the cloud computing strategy.	No	1/12/2027	12/31/2028	$ 2,751,224.04	$ 2,390,130.68	$ 540,042.72	$ 1,414,090.96			$ 429,988.00	$ 361,093.36	$ 12,091.36	$ 349,000.00				$ 261,433.93
4	2028	IT for IT Application Health	Sustainment	Shared	Information Technology for IT	Steve Ambrose	DPMD0004245	Level 3	Recommended solutions include: - Perform upgrades to ServiceNow twice a year, the IT Services Platform core tool, twice each year to ensure we do not lose support eligibility - Complete technical integrations with DTE applications where ServiceNow will create incidents as necessary - Perform monthly updates to minimize security and technical issues - Prioritize and implement new functionality and features as identified and prioritized by our business partners	**Security**: Minimize security vulnerabilities on included systems, reducing the opportunities for system disruption. Optimize visibility and monitoring of IT business applications and those services, systems, hardware and cloud infrastructure to reduce security concerns proactively. **Employee Value**: DTE Energy Information Technology employees will realize process efficiencies and improved effectiveness. DTE Energy employees that use Information Technology systems will experience reduced times for issue resolution and faster delivery of Information Technology requests that enable them to perform their jobs more efficiently and effectively. Once we don't lose the enhancement information until shortly before it is released. We cannot quantify the realized benefits until we know the content of the upgrade.	Doing nothing will have the following negative impacts: - The systems will not be eligible for support by the vendors. If this were to occur and we experience an issue, we may not be able to resolve it. This would severely degrade information technology's ability to monitor IT systems that are support DTE Energy's delivery of energy to our customers - We will not have access to security patches, introducing vulnerabilities that may be exploited by hackers to access and disrupt DTE Energy's system	Standard market-based and/or commoditized non-core energy workload - deploy in commercial cloud	ServiceNow is a public cloud solution in alignment with the cloud computing strategy.	No	1/12/2028	12/31/2028	$ 2,792,623.12	$ 2,429,579.98	$ 553,888.84	$ 1,445,790.04			$ 429,888.00	$ 367,046.24	$ 11,046.24	$ 356,000.00				$ 265,741.49
5	2026	ITAIT Tools	Sustainment	Shared	Information Technology for IT	Steve Ambrose	DPMD0004027	Level 3	**BENEFITS YEAR OF WHEN SUBSTANTIVE ITAIT TASKS SHIFT ON SUBPOINT** The solution is to continue to invest in the sustainment of ITAIT tools to provide the following capabilities: Maintain software upgrades, patching, security vulnerability remediation, and software enhancements. Business process improvements as well as integration into existing processes related to access, compliance, incident and release management, and software development. Integration of tools into DTE's application ecosystem. Regular software release management for relevant tools in which minor software enhancements and patching will be implemented. Regular maintenance for the tools with testing and deployment for critical tools such as SailPoint being performed in an established monthly cycle. Compliance process improvements related to SailPoint such as the Periodic User Access Review (PUAR) for SOX compliance as well as integrations between SailPoint and other compliance tools and activities will be performed as a part of this effort.	**Organization**: Improved Security & Risk Management - Centralized identity governance helps prevent unauthorized access and reduces the risk of data breaches. Patching of security and software bugs. Regulatory Compliance - Automates audits, access certifications, and reporting to meet regulations like NERC, SOX, etc. Operational Efficiency - Automated user provisioning, deprovisioning, and access requests. Quicker incident response times. Automated release management - Standardized software development and release management Scalability & Integration - Integration with cloud, on-prem, and hybrid environments to support business growth and complexity. Reduced Costs - Cuts down on administrative overhead, password reset tickets, and compliance penalties. **Customer**: Enhanced Data Security - Protects customer data by ensuring only authorized users have access to sensitive systems. Improved Trust & Reputation - Demonstrates a commitment to cybersecurity and compliance, which builds trust with customers. Fewer Service Disruptions - Reduced risk of insider threats or breaches ensures reliable, continuous service delivery, quicker response time to production impact.	ITAIT tools such as SailPoint have already been determined to be the right solutions for supporting DTE IT processes. There is an ongoing effort to continue the implementation of SailPoint (Automated Provisioning). The do nothing approach would increase security risk to the business due to unaddressed security vulnerabilities and potential for unauthorized access, increase risk to compliance obligations due to out of date processes or unmonitored compliance tools, inability to provision and control access to ITAIT managed tools, as well as prolong user provisioning and deprovisioning processes for SailPoint.	Standard market-based and/or commoditized non-core energy workload - deploy in commercial cloud	SailPoint system does not use cloud capabilities. PagerDuty, GitHub, and Cutover are COTS products based in th	No	1/5/2026	12/31/2026	$ 1,262,064.48	$ 571,038.88	$ 203,750.88	$ 204,000.00			$ 163,288.00	$ 691,025.60	$ 4,825.60	$ 686,200.00				$ 500,392.53
6	2027	ITAIT Tools	Sustainment	Shared	Information Technology for IT	Steve Ambrose	DPMD0004241	Level 3	**BENEFITS YEAR OF WHEN SUBSTANTIVE ITAIT TASKS SHIFT ON SUBPOINT** The solution is to continue to invest in the sustainment of ITAIT tools to provide the following capabilities: Maintain software upgrades, patching, security vulnerability remediation, and software enhancements. Business process improvements as well as integration into existing processes related to access, compliance, incident and release management, and software development. Integration of tools into DTE's application ecosystem. Regular software release management for relevant tools in which minor software enhancements and patching will be implemented. Regular maintenance for the tools with testing and deployment for critical tools such as SailPoint being performed in an established monthly cycle. Compliance process improvements related to SailPoint such as the Periodic User Access Review (PUAR) for SOX compliance as well as integrations between SailPoint and other compliance tools and activities will be performed as a part of this effort. Patching would be done on a regular monthly basis as needed.	**Organization**: Improved Security & Risk Management - Centralized identity governance helps prevent unauthorized access and reduces the risk of data breaches. Patching of security and software bugs. Regulatory Compliance - Automates audits, access certifications, and reporting to meet regulations like NERC, SOX, etc. Operational Efficiency - Automated user provisioning, deprovisioning, and access requests. Quicker incident response times. Automated release management - Standardized software development and release management Scalability & Integration - Integration with cloud, on-prem, and hybrid environments to support business growth and complexity. Reduced Costs - Cuts down on administrative overhead, password reset tickets, and compliance penalties. **Customer**: Enhanced Data Security - Protects customer data by ensuring only authorized users have access to sensitive systems. Improved Trust & Reputation - Demonstrates a commitment to cybersecurity and compliance, which builds trust with customers. Fewer Service Disruptions - Reduced risk of insider threats or breaches ensures reliable, continuous service delivery, quicker response time to production impact.	ITAIT tools such as SailPoint have already been determined to be the right solutions for supporting DTE IT processes. There is an ongoing effort to continue the implementation of SailPoint (Automated Provisioning). The do nothing approach would increase security risk to the business due to unaddressed security vulnerabilities and potential for unauthorized access, increase risk to compliance obligations due to out of date processes or unmonitored compliance tools, inability to provision and control access to ITAIT managed tools, as well as prolong user provisioning and deprovisioning processes for SailPoint.	Standard market-based and/or commoditized non-core energy workload - deploy in commercial cloud	SailPoint system does not use cloud capabilities. PagerDuty, GitHub, and Cutover are COTS products based in th	No	1/4/2027	12/31/2028	$ 1,263,494.92	$ 570,020.52	$ 207,219.32	$ 132,200.04			$ 140,601.36	$ 693,474.40	$ 14,174.36	$ 679,300.04				$ 502,875.47
7	2028	ITAIT Tools	Sustainment	Shared	Information Technology for IT	Steve Ambrose	DPMD0004241	Level 3	**BENEFITS YEAR OF WHEN SUBSTANTIVE ITAIT TASKS SHIFT ON SUBPOINT** The solution is to continue to invest in the sustainment of ITAIT tools to provide the following capabilities: Maintain software upgrades, patching, security vulnerability remediation, and software enhancements. Business process improvements as well as integration into existing processes related to access, compliance, incident and release management, and software development. Integration of tools into DTE's application ecosystem. Regular software release management for relevant tools in which minor software enhancements and patching will be implemented. Regular maintenance for the tools with testing and deployment for critical tools such as SailPoint being performed in an established monthly cycle. Compliance process improvements related to SailPoint such as the Periodic User Access Review (PUAR) for SOX compliance as well as integrations between SailPoint and other compliance tools and activities will be performed as a part of this effort.	**Organization**: Improved Security & Risk Management - Centralized identity governance helps prevent unauthorized access and reduces the risk of data breaches. Patching of security and software bugs. Regulatory Compliance - Automates audits, access certifications, and reporting to meet regulations like NERC, SOX, etc. Operational Efficiency - Automated user provisioning, deprovisioning, and access requests. Quicker incident response times. Automated release management - Standardized software development and release management Scalability & Integration - Integration with cloud, on-prem, and hybrid environments to support business growth and complexity. Reduced Costs - Cuts down on administrative overhead, password reset tickets, and compliance penalties. **Customer**: Enhanced Data Security - Protects customer data by ensuring only authorized users have access to sensitive systems. Improved Trust & Reputation - Demonstrates a commitment to cybersecurity and compliance, which builds trust with customers. Fewer Service Disruptions - Reduced risk of insider threats or breaches ensures reliable, continuous service delivery, quicker response time to production impact.	ITAIT tools such as SailPoint have already been determined to be the right solutions for supporting DTE IT processes. There is an ongoing effort to continue the implementation of SailPoint (Automated Provisioning). The do nothing approach would increase security risk to the business due to unaddressed security vulnerabilities and potential for unauthorized access, increase risk to compliance obligations due to out of date processes or unmonitored compliance tools, inability to provision and control access to ITAIT managed tools, as well as prolong user provisioning and deprovisioning processes for SailPoint.	Standard market-based and/or commoditized non-core energy workload - deploy in commercial cloud	SailPoint system does not use cloud capabilities. PagerDuty, GitHub, and Cutover are COTS products based in th	No	1/4/2028	12/31/2028	$ 1,832,060.50	$ 340,727.38	$ 151,926.34	$ 48,190.96			$ 140,601.00	$ 691,333.20	$ 12,833.24	$ 678,498.96				$ 500,529.24
8	2027	ServiceNow Application License Renewal	Sustainment	Shared	Information Technology for IT	Steve Ambrose	DPMD0004246	Level 3	The recommended solution is to renew and continue the existing ServiceNow enterprise license agreement and associated entitlements. This enables DTE to maintain uninterrupted access to the platform, remain within supported versions, and continue leveraging ServiceNow as the system of record for IT service management, operational workflows, and shared enterprise capabilities.	The primary benefit of this demand is risk avoidance and continuity of operations. License renewal ensures: Continued availability of a mission-critical enterprise platform Ongoing vendor support and security compliance Protection of prior investments in configuration, integrations, and training Stable and consistent service experiences for employees and internal customers The value is realized through sustained performance, reliability, and supportability of existing capabilities.	Alternatives considered include discontinuing the platform or replacing ServiceNow with another solution. These alternatives were not deemed viable due to the extensive enterprise adoption, integration footprint, and operational dependency on ServiceNow. DTE remains committed to ServiceNow as the strategic platform for service management and workflow automation, making license renewal the only practical and responsible option.	Standard market-based and/or commoditized non-core energy workload - deploy in commercial cloud	Aligns with DTE's Cloud Strategy.	No	1/4/2027	12/17/2027	$ 13,500,888.00	$ 13,500,888.00				$ 12,765,300.00	$ 735,888.00	$ -					$
9	2027	Advanced Privileged Access Management - NERC	Regulatory/Compliance	Shared	Information Protection Security	Steve Ambrose	DPMD0001087	Level 3	Delinea infrastructure for NERC instance. This demand is to extend the capabilities of the solution for NERC. We cannot store NERC credentials in the corporate cloud instance of the solution and NERC privileged credentials have been stored in a separate instance of the old solution. So, we have to stand-up an on-prem instance of the new platform for storing NERC credentials. Here is the recommended solution from Demand 2233 Advanced Privilege Management In 2023 DTE did procure a corporate licensing agreement and convert the sandbox environment into the cloud production environment; trust the SMEs on the new solution and start Organizational Change Management by delivering training materials and training sessions for current users on the new platform; and refine the project backlog for subsequent phases that will take place between 2026 and 2027. IPS assessed the critical PAM use cases that better fit OTS and compared the top 4 solutions. The recommended solution provides the same features, we have with our current PAM solution but also enables new capabilities for critical use cases that are not part of the current solution. These include real-time monitoring and inventory of NHI accounts, AD Bridging, just-in-time / just-enough-entitlement elevation, out of the box compliance reporting for NERC, SOX, PCI, behavioral analytics, gatekeeping and change management integration with ServiceNow.	As a more mature and modern PAM platform, Delinea provides additional use cases but most importantly is better positioned to support NERC compliance with more efficiency and effectiveness. This platform allows DTE to reach a higher PAM maturity at a faster pace. The resources and effort currently dedicated to maintaining existing platform and will be repurposed to focus on new solution functionality. The inventory of privileged accounts enables proactive definition and implementation of controls, and easier user access reviews.	Staying with existing platform will not enable support of all the critical use cases and requires significant infrastructure investment. Our staff will not be able to fully support the solution due to professional service requirements imposed by solution vendor.	Not Applicable	This solution will be with On-Prem. On-Prem will support NERC.	No	1/2/2026	12/31/2028	$ 1,070,000.00	$ 980,000.00	$ 36,948.32	$ 722,414.96			$ 107,653.00	$ 92,794.72	$ 90,000.00	$ 9,133.13	$ 80,866.80			$ 95,580.00
10	2028	Advanced Privileged Access Management - NERC	Regulatory/Compliance	Shared	Information Protection Security	Steve Ambrose	DPMD0001087	Level 3	Delinea infrastructure for NERC instance. This demand is to extend the capabilities of the solution for NERC. We cannot store NERC credentials in the corporate cloud instance of the solution and NERC privileged credentials have been stored in a separate instance of the old solution. So, we have to stand-up an on-prem instance of the new platform for storing NERC credentials. Here is the recommended solution from Demand 2233 Advanced Privilege Management In 2023 DTE did procure a corporate licensing agreement and convert the sandbox environment into the cloud production environment; trust the SMEs on the new solution and start Organizational Change Management by delivering training materials and training sessions for current users on the new platform; and refine the project backlog for subsequent phases that will take place between 2026 and 2027. IPS assessed the critical PAM use cases that better fit OTS and compared the top 4 solutions. The recommended solution provides the same features, we have with our current PAM solution but also enables new capabilities for critical use cases that are not part of the current solution. These include real-time monitoring and inventory of NHI accounts, AD Bridging, just-in-time / just-enough-entitlement elevation, out of the box compliance reporting for NERC, SOX, PCI, behavioral analytics, gatekeeping and change management integration with ServiceNow.	As a more mature and modern PAM platform, Delinea provides additional use cases but most importantly is better positioned to support NERC compliance with more efficiency and effectiveness. This platform allows DTE to reach a higher PAM maturity at a faster pace. The resources and effort currently dedicated to maintaining existing platform and will be repurposed to focus on new solution functionality. The inventory of privileged accounts enables proactive definition and implementation of controls, and easier user access reviews.	Staying with existing platform will not enable support of all the critical use cases and requires significant infrastructure investment. Our staff will not be able to fully support the solution due to professional service requirements imposed by solution vendor.	Not Applicable	This solution will be with On-Prem. On-Prem will support NERC.	No	1/2/2027	12/31/2028	$ 1,088,927.59	$ 878,496.98	$ 55,658.48	$ 722,400.04			$ 107,653.77	$ 92,794.79	$ 90,438.60	$ 8,430.60	$ 82,008.00			$ 69,471.75
11	2025	Communication Compliance and Data Loss Prevention (DLP) Diversification	Regulatory/Compliance	Shared	Information Protection Security	Steve Ambrose	DPMD0002745	Actual	2025: Configure and deploy DLP across all corporate communication/collaboration channels. This consists of developing channel-specific data loss prevention policies (relevant email, Teams chat, OneDrive, SharePoint), testing the policies, and deploying the policies across the organization. 2026: Configure and deploy communication compliance across the organization. This consists of working with several areas of the organization (Legal, HR, Ethics and Compliance) to define policies around appropriate/secure communications, developing agreed-upon policies, testing these policies, and deploying the policies across the organization.	Microsoft DLP and Communication Compliance provide comprehensive protection against a wide range of threats while also helping the organization stay in compliance with all applicable standards (PCI DSS). They tightly integrate with other Microsoft products to provide a seamless experience. Centralized management via a single console makes it easy to configure policies, manage updates, monitor communication and compliance across the organization to take action when necessary. DLP and Communication Compliance can also help the organization protect sensitive data, reduce compliance risk, improve our security posture, and protect our brand reputation. Currently only outbound email is secured with DLP. By expanding the use of DLP across all communication channels that employees use, this will help us further secure the organization's data and comply with all required standards.	Mitrixon, which was considered, was not selected. Mitrixon's Gartner position has been degraded and Microsoft has become an industry leader. The DTE strategic direction is to move to a platform strategy and away from disparate 3rd party vendor tools.	Doing Nothing is not acceptable as this will leave DTE data exposed in a potentially insecure state which may result in financial and data loss implications.	Standard market-based and/or commoditized non-core energy workload - deploy in commercial cloud	Aligns with DTE cloud security strategy.	No	1/2/2025	12/31/2026	$ 127,378.03	$ 127,378.40	$ 63,073.70	$ 24,675.00	$ 123.64		$ 39,508.04	$ -	$ -					
12	2026	Communication Compliance and Data Loss Prevention (DLP) Diversification	Regulatory/Compliance	Shared	Information Protection Security	Steve Ambrose	DPMD0002745	Level 3	2025: Configure and deploy DLP across all corporate communication/collaboration channels. This consists of developing channel-specific data loss prevention policies (relevant email, Teams chat, OneDrive, SharePoint), testing the policies, and deploying the policies across the organization. 2026: Configure and deploy communication compliance across the organization. This consists of working with several areas of the organization (Legal, HR, Ethics and Compliance) to define policies around appropriate/secure communications, developing agreed-upon policies, testing these policies, and deploying the policies across the organization.	Microsoft DLP and Communication Compliance provide comprehensive protection against a wide range of threats while also helping the organization stay in compliance with all applicable standards (PCI DSS). They tightly integrate with other Microsoft products to provide a seamless experience. Centralized management via a single console makes it easy to configure policies, manage updates, monitor communication and compliance across the organization to take action when necessary. DLP and Communication Compliance can also help the organization protect sensitive data, reduce compliance risk, improve our security posture, and protect our brand reputation. Currently only outbound email is secured with DLP. By expanding the use of DLP across all communication channels that employees use, this will help us further secure the organization's data and comply with all required standards.	Mitrixon, which was considered, was not selected. Mitrixon's Gartner position has been degraded and Microsoft has become an industry leader. The DTE strategic direction is to move to a platform strategy and away from disparate 3rd party vendor tools.	Doing Nothing is not acceptable as this will leave DTE data exposed in a potentially insecure state which may result in financial and data loss implications.	Standard market-based and/or commoditized non-core energy workload - deploy in commercial cloud	Aligns with DTE cloud security strategy.	No	1/2/2026	12/31/2026	$ 486,741.88	$ 183,741.88	$ 47,051.80	$ 57,600.00			$ 59,090.00	$ 293,000.00	$ 173,400.00	$ 109,600.00				$ 204,892.00
13	2025	Non-Windows and Mobile Endpoint Protection	Regulatory/Compliance	Shared	Information Protection Security	Steve Ambrose	DPMD0002744	Actual	The recommended solution is to configure and deploy Microsoft Defender across all corporate-owned assets that have not been onboarded into Defender yet. This solution will impact both gas and electric employees, as it involves shared assets across the organization (servers, corporate-owned mobile devices and PMCs). Year 1 – Configure policies and deploy Defender to non-Windows servers and Azure cloud servers. This consists of developing policies (such as antivirus, firewall, advanced threat protection), testing these policies, and deploying to non-Windows Linux servers and Azure cloud servers. Year 2 – Configure policies and deploy Defender to corporate-owned mobile endpoints (iOS and Android). This consists of developing mobile-specific policies (antivirus, blocked applications, mobile threat defense), testing these policies, and deploying to all corporate-owned mobile iOS and Android devices. Year 3 – Configure policies and deploy Defender to non-Windows endpoints (PMCs). This consists of developing PMC-specific policies (antivirus, firewall, advanced threat protection, removable media policies), testing these policies, and deploying to all corporate PMC endpoints.	Microsoft Defender provides comprehensive protection against a wide range of threats. It tightly integrates with other Microsoft products to provide a seamless experience. Automated threat response reduces the time required for threat response and remediation. Centralized management via a single console makes it easy to configure policies, manage updates, and monitor endpoint activity across the organization. Defender can also help the organization adhere to compliance regulations. Currently all non-Windows devices and corporate-owned mobile devices within the organization are lacking proper security controls. By deploying Microsoft Defender against these vulnerable populations, this will help the organization secure 100% of these endpoints. The value this demand will deliver to DTE is the protection that it offers IT Systems and Assets and allows IT to meet both federal and state regulations which aim to enhance the security and resilience of the power and electric sector against various cyber threats, such as malware, ransomware, denial of service attacks, phishing, insider threats, and more. However, these regulations also pose challenges and costs for the sector to comply with them, such as updating legacy systems, training staff, auditing processes, and reporting incidents. Therefore, it is important for the sector to balance the benefits and trade-offs of implementing these regulations. • The Energy Policy Act of 2005 – gives the Federal Energy Regulatory Commission (FERC) authority to oversee the reliability of the bulk power system, including approving mandatory cybersecurity reliability standards. These standards are developed by the North American Electric Reliability Corporation (NERC) and are known as "Critical Infrastructure Protection (CIP) cyber security reliability standards The Energy Independence and Security Act of 2007 – gives FERC and the National Institute of Standards and Technology (NIST) responsibilities related to coordinating the development and adoption of smart grid guidelines and standards, including cybersecurity aspects • The FERC Order No. 881 – issued in 2018 and proposed new CIP requirements for high- and medium-impact bulk electric facilities to increase the probability of early detection and mitigation of cyberattacks, especially on supply chain components. • The Michigan Cyber Disruption Response Plan – The plan defines roles and responsibilities, communication protocols, and evacuation procedures for various stakeholders, such as state agencies, local governments, private sector partners, and federal authorities. • The Michigan Public Service Commission (MPSC) – The MPSC also oversees the implementation of the NERC CIP standards by the utilities, and conducts audits and inspections to ensure compliance. The MPSC also provides guidance and resources for utilities to enhance their cybersecurity posture and resilience.	Symantec, which was considered, was not selected. Symantec's Gartner position has been degraded and Microsoft has become an industry leader.	Doing Nothing is not acceptable as this will leave DTE data exposed in a potentially insecure state which may result in financial and data loss implications.	Standard market-based and/or commoditized non-core energy workload - deploy in commercial cloud	Aligns with DTE cloud security strategy.	No	1/2/2027	12/31/2027	$ 83,311.68	$ 80,144.20	$ 10,240.12		$ 6.31		$ 29,763.93	$ 3,198.32	$ 2,041.79	$ 67.76	$ 1,028.78			$ 2,768.88
14	2027	Non-Windows and Mobile Endpoint Protection	Regulatory/Compliance	Shared	Information Protection Security	Steve Ambrose	DPMD0002744	Level 3	The recommended solution is to configure and deploy Microsoft Defender across all corporate-owned assets that have not been onboarded into Defender yet. This solution will impact both gas and electric employees, as it involves shared assets across the organization (servers, corporate-owned mobile devices and PMCs). Year 1 – Configure policies and deploy Defender to non-Windows servers and Azure cloud servers. This consists of developing policies (such as antivirus, firewall, advanced threat protection), testing these policies, and deploying to non-Windows Linux servers and Azure cloud servers. Year 2 – Configure policies and deploy Defender to corporate-owned mobile endpoints (iOS and Android). This consists of developing mobile-specific policies (antivirus, blocked applications, mobile threat defense), testing these policies, and deploying to all corporate-owned mobile iOS and Android devices. Year 3 – Configure policies and deploy Defender to non-Windows endpoints (PMCs). This consists of developing PMC-specific policies (antivirus, firewall, advanced threat protection, removable media policies), testing these policies, and deploying to all corporate PMC endpoints.	Microsoft Defender provides comprehensive protection against a wide range of threats. It tightly integrates with other Microsoft products to provide a seamless experience. Automated threat response reduces the time required for threat response and remediation. Centralized management via a single console makes it easy to configure policies, manage updates, and monitor endpoint activity across the organization. Defender can also help the organization adhere to compliance regulations. Currently all non-Windows devices and corporate-owned mobile devices within the organization are lacking proper security controls. By deploying Microsoft Defender against these vulnerable populations, this will help the organization secure 100% of these endpoints. The value this demand will deliver to DTE is the protection that it offers IT Systems and Assets and allows IT to meet both federal and state regulations which aim to enhance the security and resilience of the power and electric sector against various cyber threats, such as malware, ransomware, denial of service attacks, phishing, insider threats, and more. However, these regulations also pose challenges and costs for the sector to comply with them, such as updating legacy systems, training staff, auditing processes, and reporting incidents. Therefore, it is important for the sector to balance the benefits and trade-offs of implementing these regulations. • The Energy Policy Act of 2005 – gives the Federal Energy Regulatory Commission (FERC) authority to oversee the reliability of the bulk power system, including approving mandatory cybersecurity reliability standards. These standards are developed by the North American Electric Reliability Corporation (NERC) and are known as "Critical Infrastructure Protection (CIP) cyber security reliability standards The Energy Independence and Security Act of 2007 – gives FERC and the National Institute of Standards and Technology (NIST) responsibilities related to coordinating the development and adoption of smart grid guidelines and standards, including cybersecurity aspects • The FERC Order No. 881 – issued in 2018 and proposed new CIP requirements for high- and medium-impact bulk electric facilities to increase the probability of early detection and mitigation of cyberattacks, especially on supply chain components. • The Michigan Cyber Disruption Response Plan – The plan defines roles and responsibilities, communication protocols, and evacuation procedures for various stakeholders, such as state agencies, local governments, private sector partners, and federal authorities. • The Michigan Public Service Commission (MPSC) – The MPSC also oversees the implementation of the NERC CIP standards by the utilities, and conducts audits and inspections to ensure compliance. The MPSC also provides guidance and resources for utilities to enhance their cybersecurity posture and resilience.	Symantec, which was considered, was not selected. Symantec's Gartner position has been degraded and Microsoft has become an industry leader.	Doing Nothing is not acceptable as this will leave DTE data exposed in a potentially insecure state which may result in financial and data loss implications.	Standard market-based and/or commoditized non-core energy workload - deploy in commercial cloud	Aligns with DTE cloud security strategy.	Yes	1/2/2025	12/31/2027	$ 294,523.17	$ 175,860.17	$ 50,907.45	$ 60,200.00	$ 2,886.72		$ 57,076.00	$ 28,623.00	$ 2,223.00	$ 14,400.00		$ 12,000.00		$ 29,723.05
15	2025	Patch and Certification Management Program	Regulatory/Compliance	Shared	Information Protection Security	Steve Ambrose	DPMD0003465	Actual	Approved in U-21890																					
16	2026	Patch and Certification Management Program	Regulatory/Compliance	Shared	Information Protection Security	Steve Ambrose	DPMD0003365	Level 3	Approved in U-21890																					

17	2027	Patch and Certification Management Program	Regulatory/Compliance	Shared	Information Protection Security	Steve Ambrose	DHMD0005586	Level 3	DTE proposes a phased, enterprise-wide security modernization program to address growing cybersecurity threats and operational demands, focusing on automated certificate lifecycle management and vulnerability governance. The initiative includes Ansible-driven Secure Socket Layer (SSL)/ Transport Layer Security (TLS) certificate automation and integration of tools for continuous monitoring, Web Application Firewall (WAF) protection, and streamlined remediation. While the program promises improved compliance, reduced risk, and operational efficiency, it also outlines key risks such as integration complexity and cost management, with mitigation strategies and a multi-year implementation plan.	Minimized downtime and incidents: Automation virtually eliminates human errors in renewals and deployments, projecting a 90% reduction in service interruptions caused by expired certificates. Further reduce labor hours through targeted automation: Automation will be the primary mode for solution automation, while also evaluating and adopting additional technologies to address use cases that fall outside the capabilities of the proposed solution. Improved visibility and control through a centralized platform—integrated with ServiceNow or similar—that maintains a real-time certificate inventory, enabling comprehensive tracking, monitoring, and compliance reporting. Improved security and compliance through automated workflows that enforce corporate security standards and ensure timely certificate renewals, mitigating risks associated with expired or misconfigured certificates. Enterprise wide management of these cybersecurity functions will strengthen DTE's overall security posture, reducing the risk where malicious actors exploit vulnerabilities that could disrupt critical customer or employee services.	Several approaches were evaluated, including manual management, outsourcing to a managed service provider, in-house custom development, commercial off-the-shelf (COTS) solutions, and open-source tools. Manual processes were deemed unsustainable due to scalability issues, high error rates, and limited visibility and over cost, control, and responsiveness. Custom development offered flexibility but required significant resources and posed risks of delays. We have identified a use case where is possible to automate certificate renewals. The open-source was a viable option, but ongoing to assess other automation use cases and corresponding technologies. Thus, automation in the certificate lifecycle management as well as with the remediation of vulnerabilities. If we do nothing, we can expect the probability of human error to increase close to 8 times higher because currently certificate expiration dates are set to 1 - 2 years, and the industry is going to require a 47-day renewal window by 2028. As the number of dependencies on certificates continues to increase, a manual certificate renewal process will become unsustainable. In addition to increases in service outages and the number of known vulnerabilities related to SSL/TLS certificates.	Does not follow cloud computing strategy - exception.	Not Applicable	No	1/4/2027	12/30/2027	$ 1,894,429.51	$ 1,167,898.48	$ 298,113.66	$ 600,000.00			$ 266,795.20	$ 526,520.85	$ 376,520.85	$ 150,000.00			$ 381,201.10
18	2027	Cloud and Endpoint Security Application Health	Sustainment	Shared	Information Protection Security	Steve Ambrose	DHMD0004166	Level 3	The current production assets have already undergone evaluation and deployment phases. They are functioning within the organization's environment, meeting baseline requirements for performance, security, and compliance. These solutions are governed by documented policies and periodic reviews (e.g., QPR) or audit processes to ensure their alignment and compliance with the current DTE security posture. Endpoint Privilege Management Maintain alignment between user access rights and current corporate policies by continuously monitoring and addressing any misalignments. This ongoing process preserves the organization's established risk posture and sustains corporate security by upholding the principle of least privilege and reducing the attack surface across production endpoints. Enterprise Mobility Management Capturing endpoints that may have been missed, aligning with policies that have changed and maintaining current risk posture. Endpoint Protection Capturing endpoints that may have been missed, aligning with policies that have changed and maintaining current risk posture.	Implementing these security and compliance tools delivers significant value across the enterprise: Proactive Threat Protection Defender for Endpoints and Defender for Servers provide advanced threat detection and response, minimizing downtime and safeguarding critical assets. Centralized Access & Reduced Risk Endpoint Privilege Management limits administrative rights, preventing privilege escalation and insider threats. Secure Mobility & Productivity Mobile Device Management (MDM) and Mobile Application Management (MAM) secure corporate data on mobile devices, enabling flexible work without compromising security. Overall Impact: These solutions collectively strengthen cybersecurity posture, ensure compliance, and enable secure, efficient operations—protecting the organization's reputation and reducing financial and operational risk.	Alternative solutions were not evaluated, as the focus remains on sustaining compliance with existing systems while strengthening policies and procedures to mitigate emerging risks.	Standard-market-based and/or commoditized non-core energy workload - deploy in commercial cloud	No	1/5/2027	12/31/2027	$ 700,197.32	$ 637,187.32	$ 386,639.32	$ 15,000.00			$ 241,228.00	$ 63,000.00	$ 63,000.00				$ 45,612.00
19	2028	Cloud and Endpoint Security Application Health	Sustainment	Shared	Information Protection Security	Steve Ambrose	DHMD0004549	Level 3	The current production assets have already undergone evaluation and deployment phases. They are functioning within the organization's environment, meeting baseline requirements for performance, security, and compliance. These solutions are governed by documented policies and periodic reviews (e.g., QPR) or audit processes to ensure their alignment and compliance with the current DTE security posture. Endpoint Privilege Management Maintain alignment between user access rights and current corporate policies by continuously monitoring and addressing any misalignments. This ongoing process preserves the organization's established risk posture and sustains corporate security by upholding the principle of least privilege and reducing the attack surface across production endpoints. Enterprise Mobility Management Capturing endpoints that may have been missed, aligning with policies that have changed and maintaining current risk posture. Endpoint Protection Capturing endpoints that may have been missed, aligning with policies that have changed and maintaining current risk posture.	Implementing these security and compliance tools delivers significant value across the enterprise: Proactive Threat Protection Defender for Endpoints and Defender for Servers provide advanced threat detection and response, minimizing downtime and safeguarding critical assets. Centralized Access & Reduced Risk Endpoint Privilege Management limits administrative rights, preventing privilege escalation and insider threats. Secure Mobility & Productivity Mobile Device Management (MDM) and Mobile Application Management (MAM) secure corporate data on mobile devices, enabling flexible work without compromising security. Overall Impact: These solutions collectively strengthen cybersecurity posture, ensure compliance, and enable secure, efficient operations—protecting the organization's reputation and reducing financial and operational risk.	Alternative solutions were not evaluated, as the focus remains on sustaining compliance with existing systems while strengthening policies and procedures to mitigate emerging risks.	Standard-market-based and/or commoditized non-core energy workload - deploy in commercial cloud	No	1/3/2028	12/29/2028	$ 700,000.20	$ 637,000.20	$ 385,760.20				$ 251,240.00	$ 63,000.00	$ 63,000.00				$ 45,612.00
20	2027	Security Information & Event Management (SIEM) Storage Application Management	Sustainment	Shared	Information Protection Security	Steve Ambrose	DHMD0004202	Level 3	2027 scope - Purchase, install, and configure replacement hardware to support the QRadar storage infrastructure. This will ensure the monitoring will continue. Without this investment and hardware upgrade, DTE would have a substantial risk of failing a regulatory audit with possible negative findings and fines. Note that DTE owns perpetual IBM Qradar licenses, so no additional software license fees would be required.	QRADAR Metrics: Without it, identify risk would take much longer. Avoiding possible reputational risks would benefit DTE as more damage is likely if DTE is unable to monitor and identify cyber security risks with a timely, proactive process. Every minute of undetected and mitigated intrusion, DTE would be exposed to additional damages. The benefit would enable DTE to remain compliant for security logging as required by NERC CIP-007R4, PCI, SOX and TSA. In addition, the SIEM is utilized for cyber security monitoring and early detection of cyber incidents, which can result financial, reputational, and exposure of customer data. This will be to the benefit of the organization, our customer base and all the DTE employees to protect against malicious activity by bad actors.	Not Applicable	The existing SIEM does not utilize a cloud solution.	Yes	2/2/2027	12/29/2028	$ 550,000.00	$ 500,000.00	$ 165,674.91	$ 7,700.00	$ 206,455.81		$ 120,169.28	$ 50,000.00	$ 50,000.00				$ 36,200.00
21	2028	Security Information & Event Management (SIEM) Storage Application Management	Sustainment	Shared	Information Protection Security	Steve Ambrose	DHMD0004202	Level 3	2028 scope - Purchase, install, and configure replacement hardware to support the QRadar storage infrastructure. This will ensure the monitoring will continue. Without this investment and hardware upgrade, DTE would have a substantial risk of failing a regulatory audit with possible negative findings and fines. Note that DTE owns perpetual IBM Qradar licenses, so no additional software license fees would be required.	QRADAR Metrics: Without it, identify risk would take much longer. Avoiding possible reputational risks would benefit DTE as more damage is likely if DTE is unable to monitor and identify cyber security risks with a timely, proactive process. Every minute of undetected and mitigated intrusion, DTE would be exposed to additional damages. The benefit would enable DTE to remain compliant for security logging as required by NERC CIP-007R4, PCI, SOX and TSA. In addition, the SIEM is utilized for cyber security monitoring and early detection of cyber incidents, which can result financial, reputational, and exposure of customer data. This will be to the benefit of the organization, our customer base and all the DTE employees to protect against malicious activity by bad actors.	Not Applicable	The existing SIEM does not utilize a cloud solution.	Yes	2/2/2027	12/29/2028	$ 597,000.00	$ 543,000.00	$ 179,381.79	$ 7,500.00	$ 225,224.51		$ 131,093.73	$ 54,000.00	$ 54,000.00				$ 39,096.00
22	2025	Advanced Privileged Access Management	Return-to-Health	Shared	Information Protection Security	Steve Ambrose	DHMD0003210	Actual	Approved in U-21080																						
23	2026	Advanced Privileged Access Management	Return-to-Health	Shared	Information Protection Security	Steve Ambrose	DHMD0003210	Level 3	This funding request supports several critical Privileged Access Management (PAM) initiatives required to strengthen security posture, improve operational efficiency, and enable future state identity integrations. The scope includes the production integration to new platform, implementation of Active Directory Bridging to ensure seamless privileged access controls, and execution of comprehensive PAM Discovery to identify and onboard unmanaged privileged accounts. In addition, the effort will include the implementation of Cyberark Identity Administration (Identity Administration) to enable automated identity lifecycle connector to enable automated access governance. Lastly, the engagement includes assessment and remediation of current state PAM Privileged User Access Review (PLAR) processes to address audit gaps, improve compliance, and standardize review workflows.	Our proposed solution provides a use case that is not available with the existing platform. It has AD Bridging which means that account administration for non-windows systems (Linux/Unix) can leverage Active Directory eliminating the need for local administration on these systems. This also eliminates a dependency with our legacy IAM system Oracle Waveset, enabling its decommissioning.	Staying with Cyberark will not enable support of all the critical use cases and requirements identified in the business case. Cyberark is the only vendor that can support the solution due to professional service requirements imposed by solution vendor.	Regulated data or workload - deploy in government or sovereign cloud	Not Applicable	No	7/1/2024	12/31/2026	$ 2,114,405.94	$ 2,000,000.16	$ 83,948.25	$ 1,081,007.91		$ 822,098.00		$ 114,405.80	$ 16,687.60	$ 97,718.00				$ 82,829.00
24	2025	Cloud Security project	Return-to-Health	Shared	Information Protection Security	Steve Ambrose	DHMD0001144	Actual	Approved in U-21080																						
25	2025	Cyber Security Defense Center (CSDC) Growth and LifeCycle Management	Return-to-Health	Shared	Information Protection Security	Steve Ambrose	DHMD0001301	Actual	Show does not have 5 broken by year. Portfolio to provide information here and update Show The recommended solution will depend upon the specific asset. Options include expanding capacity via more licensing and deployments, hardware/software lifecycle management and capacity planning.	The value to the organization and its customers is to ensure defenses against cyber threats that would compromise the DTE network, information systems, and operational reliability.	A 'do-nothing' alternative is not acceptable as a lapse in the management of the CSDC monitoring infrastructure will lead to undetected and unmitigated cyber threats with a significant financial and operational impact.	Not Applicable	No	1/5/2022	12/31/2025	$ 36,014.60	$ 35,713.71		$ 36,106.50	$ 199.17	$ (18,868.08)	$ 1,276.94	$ 18,535.66	$ 2,930.80	$ 14,792.40	$ 647.08			$ 13,852.32
26	2026	Cyber Security Defense Center (CSDC) Growth and LifeCycle Management	Return-to-Health	Shared	Information Protection Security	Steve Ambrose	DHMD0002824	Level 3	Approved in U-21080																						
27	2027	Cyber Security Defense Center (CSDC) Growth and LifeCycle Management	Return-to-Health	Shared	Information Protection Security	Steve Ambrose	DHMD0002824	Level 3	Approximately sixty hardware assets are inventoried, and all have determined vendor end-of-life dates. Additional assets are acquired as part of other yearly capital investments (i.e., Cyber Excellence Program, etc.) and this project also supports their lifecycle management. The recommended solution will depend upon the specific asset. Options include expanding capacity via more licensing and deployments, hardware/software lifecycle management, and capacity planning. This Demand handles all items mentioned year over year so it would cover 2026, 2027 and 2028 for the below items: Acquisition and Deployment of Security Information and Event Management (SIEM) Licenses. The purchase and installation of SIEM licenses are essential for expanding our cybersecurity capacity monitoring. These licenses enable us to enhance our detection and defense mechanisms, especially in response to the continuously evolving cyber threats. Hardware (Replacement of server hardware, additional bandwidth, etc.) and Software Replacement (associated with the software licenses, QRadar, XSOAR, and Quolyx) As part of our proactive approach, we plan to replace hardware components that have reached their end-of-life (EOL) cycle. This ensures that our systems remain up-to-date, secure, and efficient. By adopting these measures, we aim to bolster our organization's resilience against cyber risks and maintain a robust security posture.	The value to the organization and its customers is to ensure defenses against cyber threats that would compromise the DTE network, information systems, and operational reliability.	A 'do-nothing' alternative is not acceptable as a lapse in the management of the CSDC monitoring infrastructure will lead to undetected and unmitigated cyber threats with a significant financial and operational impact.	Not Applicable	Yes	1/2/2026	12/31/2028	$ 273,519.29	$ 273,519.29	$ 45,071.60	$ 6,000.00	$ 191,066.66		$ 36,381.00	$ -							$ -
28	2028	Cyber Security Defense Center (CSDC) Growth and LifeCycle Management	Return-to-Health	Shared	Information Protection Security	Steve Ambrose	DHMD0002824	Level 3	Approximately sixty hardware assets are inventoried, and all have determined vendor end-of-life dates. Additional assets are acquired as part of other yearly capital investments (i.e., Cyber Excellence Program, etc.) and this project also supports their lifecycle management. The recommended solution will depend upon the specific asset. Options include expanding capacity via more licensing and deployments, hardware/software lifecycle management, and capacity planning. This Demand handles all items mentioned year over year so it would cover 2026, 2027 and 2028 for the below items: Acquisition and Deployment of Security Information and Event Management (SIEM) Licenses. The purchase and installation of SIEM licenses are essential for expanding our cybersecurity capacity monitoring. These licenses enable us to enhance our detection and defense mechanisms, especially in response to the continuously evolving cyber threats. Hardware (Replacement of server hardware, additional bandwidth, etc.) and Software Replacement (associated with the software licenses, QRadar, XSOAR, and Quolyx) As part of our proactive approach, we plan to replace hardware components that have reached their end-of-life (EOL) cycle. This ensures that our systems remain up-to-date, secure, and efficient. By adopting these measures, we aim to bolster our organization's resilience against cyber risks and maintain a robust security posture.	The value to the organization and its customers is to ensure defenses against cyber threats that would compromise the DTE network, information systems, and operational reliability.	A 'do-nothing' alternative is not acceptable as a lapse in the management of the CSDC monitoring infrastructure will lead to undetected and unmitigated cyber threats with a significant financial and operational impact.	Not Applicable	Yes	1/2/2026	12/31/2028	$ 271,916.48	$ 271,916.48	$ 38,468.76	$ 6,000.00	$ 191,066.72		$ 36,381.00	$ -	$ -						$ -
29	2025	Automated Provisioning	Strategic	Shared	Information Protection Security	Steve Ambrose	DHMD0001460	Actual	This project is to continue efforts to replace our end-of-life Identity and Access Management (IAM) solution, complete the SailPoint IAM implementation utilizing additional capabilities and to decommission the current legacy Oracle Waveset tool. Show does not have 5 broken by year. Portfolio to provide information here and update Show The current IAM solutions has several capabilities which will be retires over multiple years, completing the IAM solution in its entirety will allow the current IAM to be completely decommissioned. DTE will upgrade the existing platform, deploy OTAA, increase its CIPV capability and add a preproduction environment. Decommission current Oracle Waveset tool. SailPoint is the new Identity Access Governance (IAG) that aligns to SOX Compliance requirements and provides user access transparency. In 2022, onboarded 18 SOX Applications. Then in 2023, will onboard 10 SOX Application year after year through 2025. 10 per year to minimize impact and disruption to the enterprise and manage the effort in a safe and controlled manner to minimize impact to customers. 2025 Scope: • Migrate IAM (user access reviews) from legacy IAM system (Waveset) to SailPoint - Phase 1 (rfc and shell) • Enhance access approval process from Application Owner approvals to more granular, best practice based Entitlement Owner approvals • Migrate Access Requests for manually provisioned SOX applications from ServiceNow to SailPoint •Migrate identity authoritative source from current SAP HR to Successfactors 2026 Scope: • PLAR Phase 2 - automate user access reviews (data cleansing, data analysis, etc.) • TSM and non-SOX application onboarding • Integrate Privileged Access Management (PAM) application to enhance elevated account discovery and access reviews • Role Mining and Discovery - analyzing user permissions and access patterns to identify common roles and streamline access control, enhancing security and efficiency	Current capabilities cannot keep pace with increasing demands for efficient on-boarding, identity management, certification, role management, and data governance/mining access patterns. This project will provide these efficiencies. This program enables good security hygiene is performed with a governance model that protects the integrity of data, minimizes the risks of cybercriminals having the ability to gain access to key and critical systems. A well implemented IAP tool, increases the productivity and efficiency of executing a user access review, reducing the manual process of provisioning and deprovisioning access when people move or leaves the company. Will mitigate risk of Cyber threats and thefts in DTE's systems Required to maintain SOX compliance and NERC compliance	An alternative would be to continue with manual processing of provisioning and deprovisioning system access, increased security risk of access granted to remaining with end users who no longer need access. Doing nothing would not allow DTE to meeting SOX compliance, provided the security to protect and manage digital identities and increase vulnerabilities enterprise-wide to systems, users, and business.	Regulated data or workload - deploy in government or sovereign cloud	Not Applicable	Yes	9/1/2022	12/31/2026	$ 1,402,764.69	$ 1,372,781.27	$ 120,990.21	$ 1,092,756.75	$ 35,171.10	$ 1,223.28	$ 122,640.00	$ 109,982.50	$ 73,889.94	$ 35,892.10	$ 400.41			$ 88,956.49
30	2026	Automated Provisioning	Strategic	Shared	Information Protection Security	Steve Ambrose	DHMD0001460	Level 3	This project is to continue efforts to replace our end-of-life Identity and Access Management (IAM) solution, complete the SailPoint IAM implementation utilizing additional capabilities and to decommission the current legacy Oracle Waveset tool. Show does not have 5 broken by year. Portfolio to provide information here and update Show The current IAM solutions has several capabilities which will be retires over multiple years, completing the IAM solution in its entirety will allow the current IAM to be completely decommissioned. DTE will upgrade the existing platform, deploy OTAA, increase its CIPV capability and add a preproduction environment. Decommission current Oracle Waveset tool. SailPoint is the new Identity Access Governance (IAG) that aligns to SOX Compliance requirements and provides user access transparency. In 2022, onboarded 18 SOX Applications. Then in 2023, will onboard 10 SOX Application year after year through 2025. 10 per year to minimize impact and disruption to the enterprise and manage the effort in a safe and controlled manner to minimize impact to customers. 2025 Scope: • Migrate IAM (user access reviews) from legacy IAM system (Waveset) to SailPoint - Phase 1 (rfc and shell) • Enhance access approval process from Application Owner approvals to more granular, best practice based Entitlement Owner approvals • Migrate Access Requests for manually provisioned SOX applications from ServiceNow to SailPoint •Migrate identity authoritative source from current SAP HR to Successfactors 2026 Scope: • PLAR Phase 2 - automate user access reviews (data cleansing, data analysis, etc.) • TSM and non-SOX application onboarding • Integrate Privileged Access Management (PAM) application to enhance elevated account discovery and access reviews • Role Mining and Discovery - analyzing user permissions and access patterns to identify common roles and streamline access control, enhancing security and efficiency	Current capabilities cannot keep pace with increasing demands for efficient on-boarding, identity management, certification, role management, and data governance/mining access patterns. This project will provide these efficiencies. This program enables good security hygiene is performed with a governance model that protects the integrity of data, minimizes the risks of cybercriminals having the ability to gain access to key and critical systems. A well implemented IAP tool, increases the productivity and efficiency of executing a user access review, reducing the manual process of provisioning and deprovisioning access when people move or leaves the company. Will mitigate risk of Cyber threats and thefts in DTE's systems Required to maintain SOX compliance and NERC compliance	An alternative would be to continue with manual processing of provisioning and deprovisioning system access, increased security risk of access granted to remaining with end users who no longer need access. Doing nothing would not allow DTE to meeting SOX compliance, provided the security to protect and manage digital identities and increase vulnerabilities enterprise-wide to systems, users, and business.	Regulated data or workload - deploy in government or sovereign cloud	Not Applicable	No	9/1/2022	12/31/2026	$ 1,829,080.67	$ 1,590,429.43	$ 463,260.75	$ 741,761.52		$ 295,384.56		$ 324,653.84	$ 179,516.45	$ 145,000.44		$ 240.00		$ 239,048.08
31	2025	Cyber Excellence Plan (CEP) Program	Strategic	Shared	Information Protection Security	Steve Ambrose	DHMD0001468	Actual	Approved in U-21080																						
32	2026	Cyber Resilient Data Backup and Recovery	Strategic	Shared	Information Protection Security	Steve Ambrose	DHMD0001467	Level 3	Approved in U-21080																						
33	2028	Government Cloud Foundation	Regulatory/Compliance	Shared	Infrastructure Operations	Steve Ambrose	DHMD0004344	Level 3	Joint or one Government Cloud Environment (Joint Government or one Gov) (Joint) with not Joint Environment automation (jac, terra), registered landing zones, network segmentation, identity integration, SIEM/logging, key management/secrets, container enablement, and paved paths for application onboarding. Enforce policy as code for security, compliance, and FinOps guardrails. Provide migration/onboarding services and program governance. Two Year Plan with Tranches & Work Packages Year 1 (FY2026): Establish & Prove Tranche 1 – Decision & Sourcing Finalize selection; Azure Government or AWS GovCloud (one Gov Cloud for regulated workloads per strategy). Baseline FedRAMP High; aligned control mappings; define Authorized To Operate path and required evidence. Select SI partner(s); finalize SoW, staffing, and delivery model. Tranche 2 – Platform Foundation Identity: Integrate Entra ID/Azure AD or AWS IAM; establish PIM patterns. Networking: Hub/spoke VNETs or VPCs; private connectivity (ExpressRoute Gov / Direct Connect Gov). Security/Secrets: SIEM/logging, Key Vault/KMS, secrets management, baseline vulnerability mgmt. Observability: central logging/metrics/tracing patterns. Tranche 3 – Guardrails & Paved Paths Regulated landing zones with policy as code (security, compliance, FinOps). CI/CD paved paths and templates; artifact repository; golden base images. Hardened base images and custom images. Compliance reporting dashboards and control automation.	Regulatory Risk Reduction: documented control coverage, audit evidence. Time to Deliver: 20–40% faster onboarding to one of (hybrid) (large) Operational Reliability: fewer incidents through standardized guardrails Cost Control: 5–10% cost avoidance via policy & FinOps automation in 12 months	Do Nothing — rejected: regulatory risk, delivery delays, cost/complexity Two Gov Clouds — rejected for regulated workloads due to control duplication and complexity; multi -cloud remains for commercial workloads per strategy	Regulated data or workload - deploy in government or sovereign cloud	Not Applicable	Yes	1/3/2028	12/31/2029	$ 4,082,582.53	$ 3,878,421.78	$ 137,961.70	$ 2,153,600.04	$ 600,000.00	$ 599,000.04	$ 325,880.00	$ 213,140.75	$ 54,740.75	$ 158,400.00			$ 154,313.60
34	2025	Tower and Lighting Inspections and Repairs	Regulatory/Compliance	Electric	Infrastructure Operations	Steve Ambrose	DHMD0001338	Actual	The Tower and Lighting Inspections and Repairs project is an annual effort that evaluates the integrity of both the physical structures and the lighting systems on tower structures across the Network Operations Division (NOD). These structures are used to provide reliable, efficient, and redundant network systems that are used by DTE IT and DTE Business Units in support of our customers. The FCC regulations ensure the capability, security, and safety of these lines in the transmission of DTE data. To comply with these regulations, we annually select a subset of towers based upon their build age, identified as a rolling 5-year plan, to identify any physical or ground areas of concern and plan remediation responses. DTE employs a third-party organization to provide impartial analysis of the tower and site integrity, in accordance with FCC standards.	This ensures the towers that to which Network equipment is attached meet FCC Safety and Security standards which in turn ensures the Network capability used by the Enterprise. This business case will support achieving improved performance in existing operational process gaps, metrics, etc. 36 a. Providing reliable, efficient, and redundant network physical towers and tower locations 5. Providing enhanced safety c. Reducing unplanned outages	An alternative would be to execute the project with DTE personnel. This effort would increase the cost significantly due to the need to increase direct hire staffing levels. Do Nothing' would place DTE in direct conflict with the regulations of the FCC and cause fines and more importantly increase the probability that the Towers or Real Estate would no longer be secure, safe, or capable of meeting the requirements of the business or customers.	Not Applicable	network tower inspections and repairs are a part of this sustain effort and therefore cloud computing does not ap	Yes	1/2/2023	12/12/2025	$ 305,138.00	$ 305,138.81	$ 6,475.82	$ 243,284.00	$ 40,483.00	$ -	$ 14,055.00	$ -						$ -
35	2026	Tower and Lighting Inspections and Repairs	Regulatory/Compliance	Shared	Infrastructure Operations	Steve Ambrose	DHMD0001461	Level 3	Approved in U-21080																						
36	2027	Tower and Lighting Inspections and Repairs	Regulatory/Compliance	Shared	Infrastructure Operations	Steve Ambrose	DHMD0002481	Level 3	The recommended solution is to perform recurring studies on tower stability, tower load and tower safety. The studies include structural analysis, tower load analysis, foundation analysis, and tower safety analysis. The studies include phased-in approaches that generate new demands for significant structural repairs. Also, this effort permits DTE to retain frequency licenses purchased from FCC used for multiple radio systems that includes safety, load management and transfer trip.	This ensures the towers that to which Network equipment is attached meet FCC Safety and Security standards which in turn ensures the Network capability used by the Enterprise. This business case will support achieving improved performance in existing operational process gaps, metrics, etc. 36 a. Providing reliable, efficient, and redundant network physical towers and tower locations 5. Providing enhanced safety c. Reducing unplanned outages	An alternative would be to execute the project with DTE personnel. This effort would increase the cost significantly due to the need to increase direct hire staffing levels. Do Nothing' would place DTE in direct conflict with the regulations of the FCC and cause fines and more importantly increase the probability that the Towers or Real Estate would no longer be secure, safe, or capable of meeting the requirements of the business or customers.	Not Applicable	network tower inspections and repairs are a part of this sustain effort and therefore cloud computing does not ap	No	1/2/2026	12/31/2027	$ 313,545.25	$ 303,238.00	$ 10,000.00	$ 270,000.00			$ 23,238.00	$ 10,212.25	$ 10,212.25				$ 7,480.07
37	2028	Tower and Lighting Inspections and Repairs	Regulatory/Compliance	Shared	Infrastructure Operations	Steve Ambrose	DHMD0004200	Level 3	The recommended solution is to perform recurring studies on tower stability, tower load and tower safety. The studies include structural analysis, tower load analysis, foundation analysis, and tower safety analysis. The studies include phased-in approaches that generate new demands for significant structural repairs. Also, this effort permits DTE to retain frequency licenses purchased from FCC used for multiple radio systems that includes safety, load management and transfer trip.	This ensures the towers that to which Network equipment is attached meet FCC Safety and Security standards which in turn ensures the Network capability used by the Enterprise. This business case will support achieving improved performance in existing operational process gaps, metrics, etc. 36 a. Providing reliable, efficient, and redundant network physical towers and tower locations 5. Providing enhanced safety c. Reducing unplanned outages	An alternative would be to execute the project with DTE personnel. This effort would increase the cost significantly due to the need to increase direct hire staffing levels. Do Nothing' would place DTE in direct conflict with the regulations of the FCC and cause fines and more importantly increase the probability that the Towers or Real Estate would no longer be secure, safe, or capable of meeting the requirements of the business or customers.	Not Applicable	network tower inspections and repairs are a part of this sustain effort and therefore cloud computing does not ap	No	1/2/2028	12/31/2029	$ 292,781.54	$ 282,489.04	$ 10,164.00	$ 246,792.04			$ 25,523.00	$ 10,212.00	$ 10,212.00				$ 7,465.89
38	2025	Backup Environmental Growth	Sustainment	Shared	Infrastructure Operations	Steve Ambrose	DHMD0001317	Actual	In order to meet the business requirements for data storage, access and retention, we will replace aged backup and storage Infrastructure which includes storage arrays, backup compute assets (servers) and repositories (databases), and capacity with current technology that can be expanded as necessary to support DTE's requirements annually for 2023, 2024 and 2025.	Ensures business critical data is available after loss of service or an outage. Provide sufficient storage to continue to provide timely backups and recovery for applications to ensure application continuity for 2023, 2024 and 2025. EGD will maintain 99% success rate in daily, weekly and monthly backups and 100% success rate in recovery capability for all key and critical applications.	None. No alternatives are possible without impacting the Capital budget since this is a sustain effort.	Not Applicable	This project involves replacing end of life back-up assets and hence, no Cloud solution required for this effort	No	1/2/2023	12/31/2025	$ 496,810.68	$ 496,814.23	$ 115,126.21	$ 30,024.78	$ (1,522.46)	$ 258,408.75	$ 96,527.00	$ -						$ -
39	2026	Backup Environmental Growth	Sustainment	Shared	Infrastructure Operations	Steve Ambrose	DHMD0002441	Level 3	The recommended solution for 2026 is as follows: 1) Purchase additional capacity for DTE's backup infrastructure (Data Domains and PowerProtect Data Manager). 2) Install, configure and deploy additional storage capacity to ensure even distribution of backups across all the available backup infrastructure, thus ensuring there is no wastage in the capacity procured. For 2027: 1) Purchase additional capacity for DTE's backup infrastructure (Data Domains and PowerProtect Data Manager). 2) Install, configure and deploy additional capacity.	Ensures business critical data is available after loss of service or an outage. Provide sufficient storage to continue to provide timely backups and recovery for applications to ensure application continuity for 2023, 2024 and 2025. EGD will maintain 99% success rate in daily, weekly and monthly backups and 100% success rate in recovery capability for all key and critical applications.	None. No alternatives are possible without impacting the Capital budget since this is a sustain effort.	Not Applicable	This project involves replacing end of life back-up assets and hence, no Cloud solution required for this effort	Yes	1/2/2026	12/31/2027	$ 552,041.59	$ 500,041.48	$ 45,126.16	$ 60,800.00	$ 346,015.30		$ 46,779.00	$ 52,000.13	$ 28,964.13	$ 23,036.00			$ 37,648.09
40	2027	Backup Environmental Growth	Sustainment	Shared	Infrastructure Operations	Steve Ambrose	DHMD0002441	Level 3	The recommended solution for 2026 is as follows: 1) Purchase additional capacity for DTE's backup infrastructure (Data Domains and PowerProtect Data Manager). 2) Install, configure and deploy additional storage capacity to ensure even distribution of backups across all the available backup infrastructure, thus ensuring there is no wastage in the capacity procured. For 2027: 1) Purchase additional capacity for DTE's backup infrastructure (Data Domains and PowerProtect Data Manager). 2) Install, configure and deploy additional capacity.	Ensures business critical data is available after loss of service or an outage. Provide sufficient storage to continue to provide timely backups and recovery for applications to ensure application continuity for 2023, 2024 and 2025. EGD will maintain 99% success rate in daily, weekly and monthly backups and 100% success rate in recovery capability for all key and critical applications.	None. No alternatives are possible without impacting the Capital budget since this is a sustain effort.	Not Applicable	This project involves replacing end of life back-up assets and hence, no Cloud solution required for this effort	Yes	1/2/2026	12/31/2027	$ 551,064.20	$ 500,064.20	$ 44,618.54	$ 60,000.00	$ 346,069.71		$ 46,779.00	$ 51,000.10	$ 25,938.10	$ 25,062.00			$ 36,924.07
41	2028	Backup Environmental Growth	Sustainment	Shared	Infrastructure Operations	Steve Ambrose	DHMD0004286	Level 3	The recommended solution for 2028 is as follows: 1) Purchase additional capacity for DTE's backup infrastructure (Data Domains and PowerProtect Data Manager). 2) Install, configure and deploy additional storage capacity to ensure even distribution of backups across all the available backup infrastructure, thus ensuring there is no wastage in the capacity procured.	Ensures business critical data is available after loss of service or an outage. Provide sufficient storage to continue to provide timely backups and recovery for applications to ensure application continuity for 2023, 2024 and 2025. EGD will maintain 99% success rate in daily, weekly and monthly backups and 100% success rate in recovery capability for all key and critical applications.	None. No alternatives are possible without impacting the Capital budget since this is a sustain effort.	Not Applicable	This project involves replacing end of life back-up assets and hence, no Cloud solution required for this effort	Yes	1/2/2028	12/31/2028	$ 567,080.68	$ 561,000.68	$ 51,645.70	$ 57,300.00	$ 396,139.98		$ 56,515.00	$ 6,080.00	$ 3,080.00	$ 3,000.00			$ 4,401.00

										the benefit/value will be realized or achieved. Customer Experience: Self service capabilities reduce lead time and foster time to market Dashboards provide targeted visibility to elements of interest to the appropriate audience to drive data-driven strategic investment and operational decisions Mitigate Enterprise/Operational Risk: Strengthen governance and more consistent standards around system design to ensure systems are designed to scale and reduce defect rate for system deployments Drive down costs, with enhanced security and availability by leveraging CSP native solutions for aggregation, classification, routing and analysis of events and logs. Employee Engagement: Automated workflows ensures that proper approvals are obtained for requests Automations enables ITS to be more efficient and deliver requests to DTE business areas faster Event Management and Root Cause Analysis automations reduce the time to resolve incidents Machine Intelligence and workflow enables ITS to resolve incidents faster, reducing business impact Stronger engineering talent and lesser off-hour support for employees. Operational Excellence: Improve our IT operational processes like infrastructure provisioning through automation and reducing time to provision. Timely identification of system related issues resulting in faster resolution and reducing system outages both planned and unplanned. Improve the availability and performance of customer-facing and internal storm applications in the cloud to support peak loads by utilizing elasticity of the cloud and implementing business continuity/disaster recovery																												
42	2027	Cloud Automation Tools License Renewal	Sustainment	Shared	Infrastructure Operations	Steve Ambrose	DPM0050087874	Level 3	DTE uses Infrastructure as code (IaC) automation to deploy, operate and enhance its infrastructure and business applications in the cloud. These automation tools are also used to visualize cloud spend, optimize operations, improve security posture, and enhance governance. The current tools are Terraform, Ansible, Cloudformation, Cloudtrail, Cloudwatch, Cloudfront, Cloudformation and leverage the efficiencies gained through automation. Furthermore, as cloud adoption increases at DTE, risk of uncontrolled cloud spend, inefficient cloud operations and poor security posture increases significantly. The recommended solution is to renew licenses for Terraform, ONE, Dome9, Infoblox and LucidScale	Do nothing: This alternative would result in extending the restoration time for customers due to the storm applications experiencing outages and inability to dynamically scale. Similarly, outages in customer facing applications will result in decreasing customer satisfaction. Without visibility into the state of our cloud infrastructure and operations, risk of uncontrolled cloud spend, inefficient cloud operations and poor security posture will result. Change to alternate toolset: This would incur a significant implementation cost, to the tune of a minimum of $50M and similar licensing cost Revert to manual processes: This will significantly degrade ITS' operational efficiency and increase risk of uncontrolled cloud spend, inefficient cloud operations and poor security posture. No other viable alternatives exist without incurring significant risks to our infrastructure and customers.	Not Applicable	This is a license renewal effort only and cloud solution is not applicable.	No	1/1/2027	12/31/2027	$ 1,100,000.00	1,100,000.00					$ 1,042,800.00	$ 57,200.00	$ -						$ -
43	2026	Cloud Program Application Health	Sustainment	Shared	Infrastructure Operations	Steve Ambrose	DPM0050064044	Level 3	To address the risks and challenges that arise from manual infrastructure management and to resolve the cause of cloud adoption across the IT landscape to align and support DTE's goals, it is recommended to invest in ongoing support of the cloud platform built on Infrastructure as Code (IaC). This includes sustained investment in automated tooling, platform governance, documentation and engineering enablement. The recommended solution is to: Maintain and evolve IaC modules and pipelines to support changing workloads and technologies. Expand security guardrails using policy-as-code to support automated auditing required for meeting compliance requirements Invest in observability of the platform to support proactive monitoring and quick recovery from failures A.1 PCDA Scope: Maintain a reliable, repeatable infrastructure baseline that improves usability and reduces operational overhead. Capabilities provided would include: Ensure environment consistency by providing ability to mirror lower environments to match production Deploy reusable code to support Kubernetes, Dome9, Data Analytics Implement drift detection to detect and remediate drift in configuration from standards defined in IaC Standardize observability by integrating logging, metrics and deployment dashboards Policy-as-Code guardrails setup for tagging policies, resource limits and access controls Identify unused, under-utilized resources and costly resources that have been deployed using tagging policies, usage metrics and resource limits defined Dashboards to visualize KPIs and operational metrics that will enable faster identification and resolution of issues Versioned documentation, onboarding guides and code samples to standardize developer expectations and experience		The benefit/value to the Organization, Customer and Employee are: Faster delivery of business initiatives through rapid, reliable infrastructure provisioning Operational and regulatory risk reduction arising from automated compliance and security checks Optimized cloud spend by leveraging elastic resource management Career development and job satisfaction for employees with exposure to modern tools and opportunities to work on strategic initiatives Reduced burnout because of standardized infrastructure, predictable environments and fewer manual fixes Reliable customer experience with stable infrastructure that reduces downtime and increases application performance Ability to deliver personalized, innovative and future-ready offerings through scalable platform capabilities	Do nothing: This alternative would result in extending the restoration time for customers due to the storm applications experiencing outages and inability to dynamically scale. Similarly, outages in customer facing applications will result in decreasing customer satisfaction. Platform without IaC: Fail back to using ad hoc scripts and manual configurations, skipping IaC standardization. This alternative would lead to inconsistent environments, provide limited scalability, increase risk of error, slow delivery cycles, weak compliance posture, uncontrolled cloud spend and increase technical debt. No other viable alternatives exist without incurring significant risks to our infrastructure and customers.	Standard market-based and/or commoditized non-core energy workload - deploy in commercial cloud	Yes - IaC is Industry Specific (core) capability - will use public cloud per strategy requirements	Yes	1/1/2026	12/31/2026	$ 1,230,105.94	1,230,105.94	$ 651,136.23	$ 66,666.73				$ 482,303.39	$ -						$ -
44	2027	Cloud Program Application Health	Sustainment	Shared	Infrastructure Operations	Steve Ambrose	DPM0050064044	Level 3	To address the risks and challenges that arise from manual infrastructure management and to resolve the cause of cloud adoption across the IT landscape to align and support DTE's goals, it is recommended to invest in ongoing support of the cloud platform built on Infrastructure as Code (IaC). This includes sustained investment in automated tooling, platform governance, documentation and engineering enablement. The recommended solution is to: Maintain and evolve IaC modules and pipelines to support changing workloads and technologies. Expand security guardrails using policy-as-code to support automated auditing required for meeting compliance requirements Invest in observability of the platform to support proactive monitoring and quick recovery from failures A.1 PCDA Scope: Maintain a reliable, repeatable infrastructure baseline that improves usability and reduces operational overhead. Capabilities provided would include: Ensure environment consistency by providing ability to mirror lower environments to match production Deploy reusable code to support Kubernetes, Dome9, Data Analytics Implement drift detection to detect and remediate drift in configuration from standards defined in IaC Standardize observability by integrating logging, metrics and deployment dashboards Policy-as-Code guardrails setup for tagging policies, resource limits and access controls Identify unused, under-utilized resources and costly resources that have been deployed using tagging policies, usage metrics and resource limits defined Dashboards to visualize KPIs and operational metrics that will enable faster identification and resolution of issues Versioned documentation, onboarding guides and code samples to standardize developer expectations and experience		The benefit/value to the Organization, Customer and Employee are: Faster delivery of business initiatives through rapid, reliable infrastructure provisioning Operational and regulatory risk reduction arising from automated compliance and security checks Optimized cloud spend by leveraging elastic resource management Career development and job satisfaction for employees with exposure to modern tools and opportunities to work on strategic initiatives Reduced burnout because of standardized infrastructure, predictable environments and fewer manual fixes Reliable customer experience with stable infrastructure that reduces downtime and increases application performance Ability to deliver personalized, innovative and future-ready offerings through scalable platform capabilities	Do nothing: This alternative would result in extending the restoration time for customers due to the storm applications experiencing outages and inability to dynamically scale. Similarly, outages in customer facing applications will result in decreasing customer satisfaction. Platform without IaC: Fail back to using ad hoc scripts and manual configurations, skipping IaC standardization. This alternative would lead to inconsistent environments, provide limited scalability, increase risk of error, slow delivery cycles, weak compliance posture, uncontrolled cloud spend and increase technical debt. No other viable alternatives exist without incurring significant risks to our infrastructure and customers.	Standard market-based and/or commoditized non-core energy workload - deploy in commercial cloud	Yes - IaC is Industry Specific (core) capability - will use public cloud per strategy requirements	Yes	1/1/2028	12/31/2028	$ 1,746,007.48	1,746,007.48	$ 991,037.74		$ 133,333.36	$ 133,333.36	$ 482,303.39							$ -
45	2028	Cloud Program Application Health	Sustainment	Shared	Infrastructure Operations	Steve Ambrose	DPM0050064044	Level 3	To address the risks and challenges that arise from manual infrastructure management and to resolve the cause of cloud adoption across the IT landscape to align and support DTE's goals, it is recommended to invest in ongoing support of the cloud platform built on Infrastructure as Code (IaC). This includes sustained investment in automated tooling, platform governance, documentation and engineering enablement. The recommended solution is to: Maintain and evolve IaC modules and pipelines to support changing workloads and technologies. Expand security guardrails using policy-as-code to support automated auditing required for meeting compliance requirements Invest in observability of the platform to support proactive monitoring and quick recovery from failures A.1 PCDA Scope: Maintain a reliable, repeatable infrastructure baseline that improves usability and reduces operational overhead. Capabilities provided would include: Ensure environment consistency by providing ability to mirror lower environments to match production Deploy reusable code to support Kubernetes, Dome9, Data Analytics Implement drift detection to detect and remediate drift in configuration from standards defined in IaC Standardize observability by integrating logging, metrics and deployment dashboards Policy-as-Code guardrails setup for tagging policies, resource limits and access controls Identify unused, under-utilized resources and costly resources that have been deployed using tagging policies, usage metrics and resource limits defined Dashboards to visualize KPIs and operational metrics that will enable faster identification and resolution of issues Versioned documentation, onboarding guides and code samples to standardize developer expectations and experience		The benefit/value to the Organization, Customer and Employee are: Faster delivery of business initiatives through rapid, reliable infrastructure provisioning Operational and regulatory risk reduction arising from automated compliance and security checks Optimized cloud spend by leveraging elastic resource management Career development and job satisfaction for employees with exposure to modern tools and opportunities to work on strategic initiatives Reduced burnout because of standardized infrastructure, predictable environments and fewer manual fixes Reliable customer experience with stable infrastructure that reduces downtime and increases application performance Ability to deliver personalized, innovative and future-ready offerings through scalable platform capabilities	Do nothing: This alternative would result in extending the restoration time for customers due to the storm applications experiencing outages and inability to dynamically scale. Similarly, outages in customer facing applications will result in decreasing customer satisfaction. Platform without IaC: Fail back to using ad hoc scripts and manual configurations, skipping IaC standardization. This alternative would lead to inconsistent environments, provide limited scalability, increase risk of error, slow delivery cycles, weak compliance posture, uncontrolled cloud spend and increase technical debt. No other viable alternatives exist without incurring significant risks to our infrastructure and customers.	Standard market-based and/or commoditized non-core energy workload - deploy in commercial cloud	Yes - IaC is Industry Specific (core) capability - will use public cloud per strategy requirements	No	1/1/2028	12/31/2028	$ 1,134,099.64	1,134,099.64	$ 585,040.08	$ 66,666.56				$ 482,303.00						$ -
46	2025	Collaboration Application Health	Sustainment	Shared	Infrastructure Operations	Steve Ambrose	DPM0050021211	Actual	In 2022 we will continue supporting the collaboration platform to enable collaborative communications, meetings, email, calendaring, instant messaging, co-authoring, and calling. This project aims to secure investment in foundational Microsoft 365 upgrades/integrations, ensure ongoing application and collaboration improvement to support operational responsibilities from remote locations. The opportunity is list of new features provided by Microsoft voted on by a group of people (customer feedback). The above activities will be continues from 2023-2026. The additional spend will also support the execution of the Microsoft Enterprise License Agreement (ELA). If DTE chose not to execute the ELA the Collaboration Platform we would lose access to the entire suite of collaboration applications. Without the ELA we would need to purchase licenses for the Microsoft productivity software or pay substantial price increase for the solution including elimination of tiered discount.	The value of this investment enables employees to remain safe and still deliver service and support business functions – which would have been impossible before the investment in this platform. In addition, this platform enables the company strategy post-COVID, which is moving to a hybrid work environment where employees will choose to either work on-site or at a remote location which best suits the work they are required to do. Employees will have options on work location to best support and improve their productivity.	We do not have an option to do nothing with the Microsoft Cloud platform. If we do not keep the products within two releases besides impact to security, application performance and usability, Microsoft will stop the service	Standard market-based and/or commoditized non-core energy workload - deploy in commercial cloud	The investment uses the public cloud in alignment with the technology strategy for cloud computing.	Yes	1/1/2023	12/30/2025	$ 3,011,820.00	$ 1,453,898.50	$ 450,248.36	$ 1,046,098.57	$ 9,130.31	$ 1,463,264.28	$ 464,507.00	$ 357,824.10		$ 355,078.00	$ 2,846.10		$ 259,875.43
47	2026	Collaboration Application Health	Sustainment	Shared	Infrastructure Operations	Steve Ambrose	DPM0050064044	Level 3	Continuation of the support to the collaboration platform to enable collaborative communications, meetings, email, calendaring, instant messaging, co-authoring, and calling. This project aims to secure investment in foundational Microsoft 365 upgrades/integrations.	The value of this investment enables employees to remain safe and still deliver service and support business functions – which would have been impossible before the investment in this platform. In addition, this platform enables the company strategy post-COVID, which is moving to a hybrid work environment where employees will choose to either work on-site or at a remote location which best suits the work they are required to do. Employees will have options on work location to best support and improve their productivity.	We do not have an option to do nothing with the Microsoft Cloud platform. If we do not keep the products within two releases besides impact to security, application performance and usability, Microsoft will stop the service	Standard market-based and/or commoditized non-core energy workload - deploy in commercial cloud	The investment uses the public cloud in alignment with the technology strategy for cloud computing.	No	1/1/2026	12/31/2026	$ 2,459,002.65	$ 2,057,178.81	$ 1,258,022.42	$ 12,485.08			$ 786,797.28	$ 402,324.10	$ 402,324.10				$ 391,282.60
48	2027	Collaboration Application Health	Sustainment	Shared	Infrastructure Operations	Steve Ambrose	DPM0050064044	Level 3	The recommended solution is to upgrade and standardize these enterprise identity tools to current, fully supported releases, including Windows Server (like for ad identity infrastructure, the latest versions of Active Administrator), Recovery Manager for Active Directory, Change Auditor, and Entra ID Connect. From a technical and functional perspective, this establishes a secure, modern identity foundation that supports hybrid identity, real-time auditing, resilient backup and recovery, and secure synchronization between on-premises Active Directory and Entra ID. These upgrades ensure compatibility with modern authentication protocols, strengthen security posture through enhanced auditing and automated recovery capabilities, and support systems and authentication flows. Functionally, the solution improves visibility into identity changes, strengthens access governance, and reduces attack surface through modern authentication and hardened platforms. This approach resolves the problem by reducing cybersecurity, operational, and compliance risk associated with outdated identity systems. It also positions the organization to reliably support business operations, regulatory requirements, and cloud adoption without risk of forced outages or unsupported configurations. What caused the change and who is driving the change? The costs for the demand originally included the assumption that the business would provide the funding for the upgrade. Unfortunately, the business did not provide the funding and it was not reached out to the group that purchased the hardware previously and they would not be funding the hardware purchase because the group (Network Engineering) was for the last purchase part of PPE and that is no longer the case. We have to increase the cost estimate to include the purchase of new servers.	This investment strengthens the resiliency of the organization by ensuring that the identity platforms underpinning nearly all business applications and processes—Active Directory and Entra IDs—operate with maximum security, high availability, and minimal downtime. Because identity services are the "root door" to applications, infrastructure, and data, modernizing and supporting these platforms reduces the risk that authentication or access failures cascade into widespread business disruption, lost productivity, or service outages. By improving the reliability, recoverability, and security of identity services, the investment ensures employees can access critical systems when they need them, supports secure and compliant access to business data, and protects revenue-generating and mission-critical processes that depend on uninterrupted access. This directly supports business continuity, reduces operational risk during cyber incidents or system failures, and protects revenue generating and mission critical processes that depend on uninterrupted access. Modern supported server infrastructure ensures continued vendor support, compatibility with current cloud services, and access to enhanced security controls and performance improvements. Refreshed servers strengthen DTE's ability to detect threats, recover rapidly from incidents such as ransomware, and meet ongoing compliance obligations tied to identity systems. Its foundational elements to the business' applications and processes, including those that relate to identity, billing, and operations, not all revenue streams would drop in a widespread outage but a meaningful portion would become delayed, impaired, or unrecoverable. Industry outage and business impact models estimate a widespread outage would cost between $2.1M to $8.6M per day.	Do Nothing means: Increasing the risk of widespread business disruption, as identity platforms are the access gateway to nearly all applications, systems, and processes; when identity services fail, users cannot authenticate and business operations effectively stop. Continuing to run outdated or unsupported identity infrastructure heightens exposure to cyberattacks, ransomware, and credential-based compromise, since these platforms lack modern security controls and cannot support organization-wide longer-secure critical security updates. The organization also faces prolonged outage risk, as recovery from identity failures becomes slower and more complex without modern tooling for auditing, backup, and restoration. In addition, operating unsupported identity components increases the likelihood of audit findings, regulatory penalties, and compliance risk, as many regulations and cyber insurance platforms are mandatory. Collectively, these risks can result in lost productivity, revenue impact, reputational damage, and diminished confidence in the organization's ability to operate securely and reliably. The servers would be end-of-life (EOL) jeopardizing the security, resiliency, and support for DTE's identity infrastructure. The tools upgraded with this demand (Lookup Active Directory (AD) recovery, privileged administration, and low-authority auditing for Active Directory (AD) and Entra ID) strengthen security and platforms increases cybersecurity, operational, and audit risk.	Standard market-based and/or commoditized non-core energy workload - deploy in commercial cloud	Standard market-based and/or commoditized non-core energy workload - deploy in commercial cloud	No	1/1/2027	12/31/2027	$ 1,607,447.69	1,607,447.69	$ 1,002,278.50				$ 605,169.39	$ -						$ -
49	2028	Collaboration Application Health	Sustainment	Shared	Infrastructure Operations	Steve Ambrose	DPM0050064044	Level 3	Continuation of the support to the collaboration platform to enable collaborative communications, meetings, email, calendaring, instant messaging, co-authoring, and calling. This project aims to secure investment in foundational Microsoft 365 upgrades/integrations.	The value of this investment enables employees to remain safe and still deliver service and support business functions – which would have been impossible before the investment in this platform. In addition, this platform enables the company strategy post-COVID, which is moving to a hybrid work environment where employees will choose to either work on-site or at a remote location which best suits the work they are required to do. Employees will have options on work location to best support and improve their productivity.	We do not have an option to do nothing with the Microsoft Cloud platform. If we do not keep the products within two releases besides impact to security, application performance and usability, Microsoft will stop the service	Standard market-based and/or commoditized non-core energy workload - deploy in commercial cloud	The investment uses the public cloud in alignment with the technology strategy for cloud computing.	No	1/1/2028	12/31/2028	$ 1,797,634.68	1,534,828.88	$ 959,916.00				$ 574,910.88	$ 292,808.00	$ 292,808.00				$ 198,272.08
50	2026	Dell Storage Hardware Refresh	Sustainment	Shared	Infrastructure Operations	Steve Ambrose	DPM0050035721	Level 3	DTE utilizes the storage for critical enterprise applications for both external and internal customers. Renewing the agreement would allow DTE to continue fulfilling its obligations to storage and maintain customer data. Dell Warranty is part of on-going 5-year TLA that is required to maintain license compliance, software support, security patching, and operational continuity for the IBM applications supporting critical business processes. Failure to renew the TLA introduces significant operational, security, compliance, and financial risks. FY26 Renew Dell Storage agreement to cover hardware and software costs. FY27: Renew Dell Storage agreement to cover hardware and software costs.																								
51	2027	Dell Storage Hardware Refresh	Sustainment	Shared	Infrastructure Operations	Steve Ambrose	DPM0050035721	Level 3		Implementation of this agreement would ensure continued storage support for critical enterprise applications that host both external and internal customer data.	Do Nothing: This is not an alternative as downtime related to storage issues will increase significantly resulting in critical application downtime which in turn would result in prolonged downtime for DTE's customers.	Not Applicable	This effort is to execute storage contract and Cloud solution is not required.	No	1/1/2026	12/31/2027	$ 1,385,764.16	1,385,764.16	$ 471.12	$ 2,469.00		$ 1,027,653.04	$ 55,240.00	$ -						$ -
52	2028	Dell Storage Hardware Refresh	Sustainment	Shared	Infrastructure Operations	Steve Ambrose	DPM0050035721	Level 3		Implementation of this agreement would ensure continued storage support for critical enterprise applications that host both external and internal customer data.	Do Nothing: This is not an alternative as downtime related to storage issues will increase significantly resulting in critical application downtime which in turn would result in prolonged downtime for DTE's customers.	Not Applicable	This effort is to execute storage contract and Cloud solution is not required.	No	1/1/2028	12/31/2028	$ 1,508,001.73	1,078,000.48				$ 1,022,758.48	$ 56,242.00	$ 427,001.25	$ 427,001.25				$ 309,148.93
53	2025	Endpoint End of Life Electric Support Services	Sustainment	Electric	Infrastructure Operations	Steve Ambrose	DPM0050015321	Actual	Approved in U-21089																					
54	2026	Endpoint End of Life Electric Support Services	Sustainment	Electric	Infrastructure Operations	Steve Ambrose	DPM0050015321	Level 3	Approved in U-21089																					
55	2027	Endpoint End of Life Electric Support Services	Sustainment	Electric	Infrastructure Operations	Steve Ambrose	DPM0050015321	Level 3	This demand is a year-over-year initiative to provide staffing solution to the ETX team. The recommended solution is to continue the Managed Service Agreement for 2026 and 2027. The Managed Service Agreement will address support services provided by Tech hub within defined Service Level targets for the ETX team. The areas of support provided within the MSA are deployments and imaging of end-of-Life assets like desktops, laptops etc. and/or services necessary to support endpoint asset health lifecycle. This service will also include a 'Tech Hub' that will provide bell hours per day support of walk-up customers at the Tech Hub location - administrating setup and deployment of software and hardware to end users including training and users on deployed equipment.	By providing a Managed Service in support of end user operational hardware and operating system issues, DTE will be able to maintain the capabilities of the business workforce's endpoint devices. NOTE: The following words are the original verbiage and have been left for record keeping. 1) Hire direct employees 2) Outsource to a non-standard vendor. A "do nothing" alternative is not in scope because of an increased burden on other support groups who develop applications or service the devices and the applications used on them. If support and maintenance is not available the device end users will have decreased satisfaction due to higher failure rates and reduced performance.	Not Applicable	This project is a service level agreement support and hence, no Cloud solution required for this effort	No	1/1/2026	12/31/2027	$ 898,508.34	898,508.34		$ 853,000.84			$ 45,508.50	$ -						$ -
56	2028	Endpoint End of Life Electric Support Services	Sustainment	shared	Infrastructure Operations	Steve Ambrose	DPM0050042307	Level 3	This demand is a year-over-year initiative to provide staffing solution to the ETX team. The recommended solution is to continue the Managed Service Agreement for 2028 and 2029. The Managed Service Agreement will address support services provided by Tech hub within defined Service Level targets for the ETX team The areas of support provided within the MSA are deployments and imaging of end-of-Life assets like desktops, laptops etc. and/or services necessary to support endpoint asset health lifecycle. This service will also include a 'Tech Hub' that will provide bell hours per day support of walk-up customers at the Tech Hub location - administrating setup and deployment of software and hardware to end users including training and users on deployed equipment.	By providing a Managed Service in support of end user operational hardware and operating system issues, DTE will be able to maintain the capabilities of the business workforce's endpoint devices. NOTE: The following words are the original verbiage and have been left for record keeping. 1) Hire direct employees 2) Outsource to a non-standard vendor. A "do nothing" alternative is not in scope because of an increased burden on other support groups who develop applications or service the devices and the applications used on them. If support and maintenance is not available the device end users will have decreased satisfaction due to higher failure rates and reduced performance.	Not Applicable	This project is a service level agreement support and hence, no Cloud solution required for this effort	No	1/1/2028	12/31/2028	$ 898,200.96	898,200.96		$ 852,999.96			$ 45,201.00	$ -						$ -
57	2026	Enterprise Monitoring Licensing Renewal	Sustainment	Shared	Infrastructure Operations	Steve Ambrose	DPM0050027778	Level 3	Approved in U-21089																					
58	2025	Enterprise Monitoring Strategy Operational Growth	Sustainment	Shared	Infrastructure Operations	Steve Ambrose	DPM0050051322	Actual	Beginning 2023 through 2025, DTE would manage the monitoring of all portfolio applications and support individually tailor monitors across all portfolios to identify applications and business transactions for improved Ingra/critical application monitoring across portfolios. DTE would also acquire and deploy the necessary technology to improve application and network performance monitoring. This would provide the organization with comprehensive visibility into business transactions, KPIs, Orchestration for Event Resolution – to transform data through analytics into actionable intelligence – (expanding Operational Excellence and Customer Experience). Provide real-time and historical analysis to the event View Technology to assist. Implementation of this solution improves the overall IT Landscape for faster response to outages and degraded performance which reduces mean-time to repair. This in turn reduces the amount of times the customers are negatively impacted by system downtime. In addition to the above scope, additional items have been identified for implementation from 2024 through 2025: 2024- Gigamon architecture changes. Gigamon gathers network statistics and distributes the information to Network Performance and Network Security. Migrating off of 4 Gigamon network appliances (devices) that are end of life 4 devices that will be retired. Gigamon Modes: 2 x HC2, a x TA10s. Recollingue- 4 appliances Buy additional 1 – 2 devices (appliances or expansion) based on sizing analysis. Include wiring. hardware for the 1-2 additional appliances; HC3 and/or TA25. labor to support the implementation 2024- Network performance monitoring (Netscout). Netscout ingests network data from Gigamon that gives us network performance statistics. Refresh/upgrade Netscout monitoring systems. Netscout server hardware and software & labor to support implementation.	Customer value is situational awareness that instantiates either preventing negative impact to service or reducing downtime once service has been impacted.	A "do nothing" alternative would halt the current operationalization of monitoring and negatively impact the Company's ability and customer expectations around providing rapid responses to customer, business, and end-user concerns.	Yes	Dynatrace has migrated to a cloud-based solution. Other monitoring tools are not architected to be cloud compatible.	Yes	1/1/2023	12/31/2025	$ 761,410.00	$ 631,398.48	$ 354,983.19	$ 48,570.10	$ 7,542.02		$ 229,301.00	$ 130,013.54	$ 86,851.27	$ 43,161.80	$ 0.47		$ 108,011.98
59	2026	Enterprise Monitoring Strategy Operational Growth	Sustainment	Shared	Infrastructure Operations	Steve Ambrose	DPM0050051322	Level 3	Approved in U-21089																					
60	2027	Enterprise Monitoring Strategy Operational Growth	Sustainment	Shared	Infrastructure Operations	Steve Ambrose	DPM0050051322	Level 3	The recommended solution for 2028 is as follows: 1) Expand application monitoring of all critical applications from 81% in 2025 to 83% in 2026. 2) Assess, plan, and deploy WPOM replacement. 3) Assess, plan, and deploy WhatsUpGold replacement. 2027 scope: 1) Expand application monitoring to 85% of all critical applications (from 83% in 2026). 2) Expand scope and depth of EOD monitoring to more fully leveraging the technology deployed in 2026. Implementation of this solution will improve the overall IT Landscape for faster response to outages and degraded performance which will reduce mean-time to repair, thereby reducing the amount of times the customers are negatively impacted by system downtime. It will also help reduce the frequency of outages by increasing awareness of emerging performance problems in time to take preventive/remediation actions.	Customer value is situational awareness that instantiates either preventing negative impact to service or reducing downtime once service has been impacted.	A "do nothing" alternative would halt the current operationalization of monitoring and negatively impact the Company's ability and customer expectations around providing rapid responses to customer, business, and end-user concerns.	Yes	Dynatrace has migrated to a cloud-based solution. Other monitoring tools are not architected to be cloud compatible.	No	1/1/2026	12/31/2027	$ 669,000.24	500,000.24	$ 172,002.24	$ 40,000.00			$ 287,998.00	$ 100,000.00		$ 100,000.00			$ 72,400.00
61	2025	Field Communications Network FCN Growth and Upgrade	Sustainment	Shared	Infrastructure Operations	Steve Ambrose	DPM0050015324	Actual	Approved in U-21089																					
62	2026	Field Communications Network FCN Growth and Upgrade	Sustainment	Shared	Infrastructure Operations	Steve Ambrose	DPM0050015324	Level 3	Approved in U-21089																					
63	2027	Field Communications Network FCN Growth and Upgrade	Sustainment	Shared	Infrastructure Operations	Steve Ambrose	DPM0050015444	Level 3	This project will continue modernizing Distribution Operations Field Communications Network assets, update the wireless systems to ensure availability of load management, and replace unsupported serial radios and substation alarms from 2026 through 2027. These efforts will ensure that the core Field Communications Network assets can support the projected utilization and automation requirements of the business. This will support the growing capacity for operational technology, automation, redundancy, and remote management of critical systems. The solution is replacing older communication mechanisms used in the field to control SCADA (supervisory control and data acquisition) and RTUs (Remote Terminal Unit), as the world has moved into IP (Internet Protocol) supported devices, many of our substations still used serial communications. This will enable the modernization of our controls over how power is delivered in the grid. This project will expand the use of our dark fiber infrastructure to provide our EDOC (Electrical System Operation Center) better control of power delivery to our customers. Ciena devices will be added to our substations to provide communication paths back into the EDOC. The useful life of these devices is approximately 7 to 10 years depending upon bandwidth needs of applications used in the field. The current infrastructure supports 100Gb with capabilities into 1Tb transfer rates of data.	Ensures redundant communication mandated as a load balancing authority in the case of the loss of a primary network in order to provide uninterrupted business processes.	Alternate technology solutions include complete replacement of core routers, switches, gateways, and firewalls, which were rejected because supplanting a 10-year platform and investment would cause an interruption of service for key and critical systems, which depend on this network. Doing nothing would directly impact the requirements of the FCC that would in turn have a direct impact on the electrical grid management and load balancing authority requirements.	Not Applicable	This only applies to hardware, therefore does not require any cloud computing effort.	No	1/1/2026	12/31/2027	$ 398,255.52	398,255.52	$ 54,601.56	$ 310,605.08			$ 44,653.96	$ -						$ -
64	2028	Field Communications Network FCN Growth and Upgrade	Sustainment	Shared	Infrastructure Operations	Steve Ambrose	DPM0050042316	Level 3	This project will continue modernizing Distribution Operations Field Communications Network assets, update the wireless systems to ensure availability of load management, and replace unsupported serial radios and substation alarms from 2026 through 2027. These efforts will ensure that the core Field Communications Network assets can support the projected utilization and automation requirements of the business. This will support the growing capacity for operational technology, automation, redundancy, and remote management of critical systems. The solution is replacing older communication mechanisms used in the field to control SCADA (supervisory control and data acquisition) and RTUs (Remote Terminal Unit), as the world has moved into IP (Internet Protocol) supported devices, many of our substations still used serial communications. This will enable the modernization of our controls over how power is delivered in the grid. This project will expand the use of our dark fiber infrastructure to provide our EDOC (Electrical System Operation Center) better control of power delivery to our customers. Ciena devices will be added to our substations to provide communication paths back into the EDOC. The useful life of these devices is approximately 7 to 10 years depending upon bandwidth needs of applications used in the field. The current infrastructure supports 100Gb with capabilities into 1Tb transfer rates of data.	Ensures redundant communication mandated as a load balancing authority in the case of the loss of a primary network in order to provide uninterrupted business processes.	Alternate technology solutions include complete replacement of core routers, switches, gateways, and firewalls, which were rejected because supplanting a 10-year platform and investment would cause an interruption of service for key and critical systems, which depend on this network. Doing nothing would directly impact the requirements of the FCC that would in turn have a direct impact on the electrical grid management and load balancing authority requirements.	Not Applicable	This only applies to hardware, therefore does not require any cloud computing effort.	No	1/1/2028	12/31/2028	$ 482,766.88	482,766.88	$ 91,287.86	$ 310,000.00			$ 81,499.00	$ -	$ -					$ -
65	2026	Microsoft License Renewal	Sustainment	Shared	Infrastructure Operations	Steve Ambrose	DPM0050002464	Level 3	In 2020 - Renewal of Microsoft Enterprise Agreement (renewed every 3 years) and continuation of the support to the collaboration platform to enable collaborative communications, meetings, email, calendaring, instant messaging, co-authoring, and calling. This project aims to secure investment in foundational Microsoft 365 upgrades/integrations.	The value of this investment enables employees to remain safe and still deliver service and support business functions – which would have been impossible before the investment in this platform. In addition, this platform enables the company strategy post-COVID, which is moving to a hybrid work environment where employees will choose to either work on-site or at a remote location which best suits the work they are required to do. Employees will have options on work location to best support and improve their productivity.	We do not have an option to do nothing with the Microsoft Cloud platform. If we do not keep the products within two releases besides impact to security, application performance and usability, Microsoft will stop the service	Standard market-based and/or commoditized non-core energy workload - deploy in commercial cloud	The investment uses the public cloud in alignment with the technology strategy for cloud computing.	No	1/1/2026	12/31/2026	$ 27,595,849.72	27,595,849.72	$ 1,177.80			$ 26,258,000.60	$ 1,364,671.30	$ -	$ -	$ -			$ -

										BENEFITS STUDY																		
66	2026	Network Engineering License Renewals	Sustainment	Shared	Infrastructure Operations	Steve Ambrose	DPMD0003917	Level 3	The recommended solution is to renew the contracts for Cisco and Infoblox licenses that are due for renewal in 2026. These network and telecommunication services are engineered and operated using strategic vendor solutions and platforms including Cisco and Infoblox etc. With the exception of Cisco Smart Net Total Care (SNTC) licenses, we have entered into multi-year contracts for subscription and support. By entering into a 3-year contract agreements, gives DTE: Ability to move CAPEX to CAPEX Better leverage with vendors by having consolidated higher dollar amounts and consequently potential higher discounts. And in case DTE wants to change the direction with regards to a vendor/technology, it gives DTE a buffer period to change the direction and not be locked for 1 year. Prices are locked for 3 year period	Renewal of the existing contracts ensure on-going support to DTE's network infrastructure services like WAN, telephony, Wireless Area Network, Local Area Network, Internet Protocol Address Management services including Domain Name System and Dynamic Host Configuration Protocol. These infrastructures help maintain network communication between energy generation and distribution and DTE's field staff. Customer Experience- DTE's Network and Telecommunication infrastructure is one of the 3 most important infrastructures in DTE. This infrastructure provides services to all of DTE including WiFi, Telephony, WAN, LAN, IPWR services etc. These services are essential and critical to DTE in SAFELY and RELIABLY operating including generating, distributing energy, Customer Service, Crew Safety across our territories. Employee Engagement- DTE's Network and Telecommunication infrastructure is one of the 3 most important infrastructures in DTE. This infrastructure provides services to all of DTE including WiFi, Telephony, WAN, LAN, IPWR services etc. These services are essential and critical to DTE in SAFELY and RELIABLY operating including generating, distributing energy, Customer Service, Crew Safety across our territories. Affordability and Growth- DTE's Network and Telecommunication infrastructure is one of the 3 most important infrastructures in DTE. This infrastructure provides services to all of DTE including WiFi, Telephony, WAN, LAN, IPWR services etc. These services are essential and critical to DTE in SAFELY and RELIABLY operating including generating, distributing energy, Customer Service, Crew Safety across our territories. Operational Reliability- DTE's Network and Telecommunication infrastructure is one of the 3 most important infrastructures in DTE. This infrastructure	1) Do Nothing: This alternative is not possible as it will result in a network communication breakdown between critical systems including the ones that are utilized for generating and distributing energy. No other alternatives have been considered as DTE has a strategic investment and partnership with these vendors/platforms.	Not Applicable	This effort focuses on contract renewals and cloud solution is not required.	No	1/1/2026	12/31/2026	$ 2,200,000.00	$ 2,200,000.00				$ 2,089,600.00	$ 114,400.00							
67	2025	Network Hardening and Operations	Sustainment	Shared	Infrastructure Operations	Steve Ambrose	DPMD0001154	Actual	Approved in U-21080																			
68	2026	Network Hardening and Operations	Sustainment	Shared	Infrastructure Operations	Steve Ambrose	DPMD0001458	Level 3	Approved in U-21080																			
69	2027	Network Hardening and Operations	Sustainment	Shared	Infrastructure Operations	Steve Ambrose	DPMD0001458	Level 3	In 2026 and 2027, this business case will address the fulfilling of the hardening requirements of Network infrastructure to offer sustained quality of network services to various DTE businesses including essential and critical business functions. Additionally, DTE would procure routers, switches, subscriptions, designs and necessary labor to deploy them. This is a year-over-year demand, where DTE needs to assess its networks and make them robust where needed. Scope includes hardware, software, designs and architecture. Each year the scope is established by working with various stakeholders to identify and prioritize networks that need assessment and hardening. The scope of procurement would be dependent on the result of the assessment.	Ensures the timely execution of work mandated by business driven initiatives in order to improve or maintain the health of our networks. This business case will address the fulfilling of the Network Engineering commitments through resiliency agreement managed under Professional Services Agreement (PSA), operating at agreed upon Service Levels Agreements (SLAs). Thus, Network Engineering will ensure sustained quality, availability, scalability and reliability of DTE networks.	Not Applicable	This is a MSA support case therefore cloud computing does not apply.	No	1/1/2026	12/31/2027	$ 400,000.15	$ 400,000.15	$ 120,018.50	$ 196,543.65			$ 83,138.00	$ -					$ -
70	2028	Network Hardening and Operations	Sustainment	Shared	Infrastructure Operations	Steve Ambrose	DPMD0004213	Level 3	In 2028 and 2029, this business case will address the fulfilling of the hardening requirements of Network infrastructure to offer sustained quality of network services to various DTE businesses including essential and critical business functions. Additionally, DTE would procure routers, switches, subscriptions, designs and necessary labor to deploy them. This is a year-over-year demand, where DTE needs to assess its networks and make them robust where needed. Scope includes hardware, software, designs and architecture. Each year the scope is established by working with various stakeholders to identify and prioritize networks that need assessment and hardening. The scope of procurement would be dependent on the result of the assessment.	Ensures the timely execution of work mandated by various business driven initiatives in order to improve or maintain the overall health of our networks. This business case will address fulfilling of the Network Engineering commitments through hardening network infrastructure operating at agreed upon Service Level Agreements (SLAs). Thus, Network Engineering will ensure sustained quality, availability, scalability and reliability of DTE networks.	Not Applicable	This is a on-prem network sustain effort and cloud technology will not be utilized.	No	1/1/2028	12/31/2029	$ 410,505.48	$ 400,505.48	$ 93,925.32	$ 254,999.96			$ 71,580.00	$ 10,000.00	$ 10,000.00				$ 7,240.00
71	2025	Palo Alto License Renewal	Sustainment	Shared	Infrastructure Operations	Steve Ambrose	DPMD0002757	Actual	Approved in U-21080																			
72	2028	Palo Alto License Renewal	Sustainment	Shared	Infrastructure Operations	Steve Ambrose	DPMD0004239	Level 3	In 2025 Palo Alto licensing was renewed to ensure functionality and supportability of network security assets needed for DTE's IT and OT Control networks. This licensing and support will expire in 2028 needing a renewal. Palo Alto is critical for DTE as it provides security posture for most of our critical assets such as APP-Control, Infrastructure and communication, electric SCADA system communication in the field, GAS SCADA communication, DTE's windpark communication, etc.	Customer Experience- Protect all our customers (>1.1 million) information, thereby reducing/preventing NPSC complaints. Due to increase in cyber threats, there is a need to implement this initiative, without which customer complaints could increase by 10% Employee Engagement- Significant improvement of experience for all DTE employees (~10,000) Due to increase in cyber threats, there is a need to implement this initiative, without which end user endpoints compromised could increase by 20% Affordability and Growth- DTE's Network and Telecommunication infrastructure is one of the 3 most important infrastructures. Failure to secure a single incident of data breach provide significant cost avoidance for DTE (https://www.ibm.com/blog/cost-of-data-breach) Cost Benefit- Cost Avoidance can not be used as Cost Benefit only for affordability and growth Operational Reliability- Significant impact attributed to unplanned system/application outages, due to an increase in cyber threats vulnerability exploitation. There is a need to implement this initiative, without which the systems and applications could experience an increase in unplanned outages by 10%.	Not Applicable	The solution that requires license renewal is deployed on-prem and hence no cloud solution is required.	No	1/1/2028	12/31/2028	$ 5,880,798.00	$ 5,880,798.00				$ 5,375,000.00	$ 305,798.00	$ -					$ -
73	2025	Server Engineering Support Services	Sustainment	Shared	Infrastructure Operations	Steve Ambrose	DPMD0001336	Actual	Because this effort is a Managed Service Agreement, the recommended solution is to provide the following services incident management, service request processing, project support, troubleshooting, vulnerability management and upgrades for servers and databases.	This effort provides the necessary compute engineering/knowledge currently unavailable within the IT Compute department ensuring that scheduled efforts from either project or operational demand meets the business need.	Not Applicable	This is an operational support service level agreement and hence, no cloud computing is required for this effort.	No	1/1/2023	12/31/2025	$ 4,676,338.03	$ 4,676,338.07	$ 173,075.12	$ 3,016,942.28	$ (540,906.35)	$ 1,617,730.01	$ 417,242.00	$ -	$ -					$ -
74	2026	Server Engineering Support Services	Sustainment	Shared	Infrastructure Operations	Steve Ambrose	DPMD0001460	Level 3	Approved in U-21080																			
75	2027	Server Engineering Support Services	Sustainment	Shared	Infrastructure Operations	Steve Ambrose	DPMD0001480	Level 3	Because this effort is a Managed Service Agreement, the recommended solution is to provide the following services incident management, service request processing, project support, troubleshooting, vulnerability management and upgrades for servers and databases.	This effort provides the necessary compute engineering/knowledge currently unavailable within the IT Compute department ensuring that scheduled efforts from either project or operational demand meets the business need.	Not Applicable	This is an operational support service level agreement and hence, no cloud computing is required for this effort.	No	1/1/2026	12/31/2027	$ 3,334,426.68	$ 3,096,989.97	$ 2,767.81	$ 2,904,554.14			$ 162,898.00	$ 4,409.75	$ 2,826.75	$ 1,600.00			$ 3,264.00
76	2028	Server Engineering Support Services	Sustainment	Shared	Infrastructure Operations	Steve Ambrose	DPMD0004296	Level 3	Because this effort is a Managed Service Agreement, the recommended solution for 2028 and 2029 is to provide the following services: project support, solution evaluation, vulnerability management and upgrades for servers and databases. The planned spend reflects this capital labor supporting the deployment of the capital assets purchased under the End Of Life program.	This effort provides the necessary compute engineering/knowledge currently unavailable within the IT Compute department ensuring that scheduled efforts from either project or operational demand meets the business need.	Not Applicable	This is an operational support service level agreement and hence, no cloud computing is required for this effort.	No	1/1/2028	12/31/2029	$ 3,101,064.68	$ 3,101,064.68		$ 2,941,804.68			$ 159,260.00	$ -					$ -
77	2025	VMWare License Renewal	Sustainment	Shared	Infrastructure Operations	Steve Ambrose	DPMD0002871	Actual	Approved in U-21080																			
78	2025	Conference Room Audio Video Support	Return to Health	Shared	Infrastructure Operations	Steve Ambrose	DPMD001158	Actual	In 2023 and 2024, this effort will provide full technical replacement and support of the Audio Visual equipment in over 500 conference rooms at 30 DTE facilities around the state. Inventory and preventative maintenance of AV equipment in the conference rooms and improved support of Executive Rooms including Broadcfe.v AV hardware and software systems is in scope of this project. In 2025, DTE would upgrade around 130 conference rooms in our service centers and FERC's to make them TEAMS compatible. In addition to this, DTE would also refre and replace the existing conference rooms with new AV devices like microphones, cabling, TVs, camera's etc. This demand benefits both Gas and Electric business units.	Provides the technology and support necessary for onsite conference room communication connection to maintain employee productivity. The outcome of the business case is to provide exceptional customers service in relation to the support of conference rooms, and the inventory and maintenance of AV equipment in them.	Not Applicable	These are physical components connected to DTE Network hence no Cloud solution is required.	Yes	1/1/2023	12/31/2025	$ 291,939.69	$ 291,938.61	$ 34,242.53	$ 108,416.42	$ 75,303.48		$ 42,976.00	$ -	$ -				$ -
79	2026	Conference Room Audio Video Support	Return to Health	Shared	Infrastructure Operations	Steve Ambrose	DPMD001442	Level 3	Approved in U-21080																			
80	2027	Conference Room Audio Video Support	Return to Health	Shared	Infrastructure Operations	Steve Ambrose	DPMD001442	Level 3	This is a continuation of previous investment (2023 - 2025) and in 2026 and 2027, this effort will provide full technical replacement and support of the Audio Visual equipment in over 500 conference rooms at 30 DTE facilities around the state. Additionally, Inventory and preventative maintenance of AV equipment in the conference rooms and improved support of Executive Rooms including Broadcfe.v AV hardware and software systems is in scope of this project.	Provides the technology and support necessary for onsite conference room communication connection to maintain employee productivity. The outcome of the business case is to provide exceptional customers service in relation to the support of conference rooms, and the inventory and maintenance of AV equipment in them.	Not Applicable	These are physical components connected to DTE Network hence no Cloud solution is required.	No	1/1/2026	12/31/2027	$ 249,281.79	$ 249,281.79	$ 101,790.75	$ 60,798.00			$ 84,703.00	$ -					$ -
81	2028	Conference Room Audio Video Support	Return to Health	Shared	Infrastructure Operations	Steve Ambrose	DPMD004254	Level 3	This is a continuation of previous investment (2026 - 2027) and in 2028 and 2029, this effort will provide full technical replacement and support of the Audio Visual equipment in over 500 conference rooms at 30 DTE facilities around the state. Additionally, Inventory and preventative maintenance of AV equipment in the conference rooms and improved support of Executive Rooms including Broadcfe.v AV hardware and software systems is in scope of this project.	Provides the technology and support necessary for onsite conference room communication connection to maintain employee productivity. The outcome of the business case is to provide exceptional customers service in relation to the support of conference rooms, and the inventory and maintenance of AV equipment in them.	Not Applicable	These are physical components connected to DTE Network hence no Cloud solution is required.	Yes	1/1/2028	12/31/2029	$ 249,090.34	$ 249,090.36	$ 99,680.40	$ 63,989.96			$ 85,420.00	$ -					$ -
82	2025	Data Center Modernization and Optimization	Return to Health	Shared	Infrastructure Operations	Steve Ambrose	DPMD002490	Actual	Approved in U-21080																			
83	2026	Data Center Modernization and Optimization	Return to Health	Shared	Infrastructure Operations	Steve Ambrose	DPMD002490	Level 3	Approved in U-21080																			
84	2027	Data Center Modernization and Optimization	Return to Health	Shared	Infrastructure Operations	Steve Ambrose	DPMD002490	Level 3	Based on this thorough evaluation of the core Data center components, our recommended solution is to replace end of life Uninterruptable Power Supply hardware, end of life power distribution units with smart PDUs that can be monitored and maintained remotely, and end of life batteries for the UPS units. These assets are critical to our business due to their age and longevity. These replacements are critical to avoiding unplanned outages to our systems which can impact our external customers. Below is the timeline for the scope we intend to do. . . . Additional scope is to add battery to replace power conditioning equipment that will reach end of life in 2027. Specific equipment affected includes DOC UPS 5B & 11 capacitors, eDOC UPS 1 & 2 batteries, and the Gas Dispatch UPSbatteries/capacitor arrays. 2025: Replacement of 1 UPS in DOC. 1 UPS and its associated batteries in Alternate SOC. Additionally, capacitors for 2 UPS in EDOC will be replaced. 2026: Replacement of UPS and it's batteries for Energy Dispatch. Replacement of batteries for Call Center UPS 2027: Replacement of batteries for 2 UPS in EDOC. DOC UPS 5B & 11 capacitors, eDOC UPS 1 & 2 batteries, and the Gas Dispatch UPSbatteries/capacitor arrays The UPS's and the associated batteries are for the Data Centers that house IT assets for both Electric and Gas.	This effort provides DTE with the foundation to be the best run energy company in North America. In that DTE depends on a stable Data Center environment to host its complete portfolio of applications and data. Failure of any key Data Center asset can result in unplanned outages which will decrease customer satisfaction, lower employee engagement and mandate costly, corrective maintenance. This effort will ensure that the applications, data and processing of and are capable of supporting the power requirements of the assets that host these applications and internet data.	Not Applicable	The data centers are established physical buildings that cannot be moved without substantial budgetary increases. Thus, this effort increases probability of impacts to the business. Do Nothing: Not replacing end of life components such as the UPS and battery banks puts the data center at a greater risk if there is an interruption in power supplying the data centers. Maintenance and repair costs will be higher as well. Leaving the floor as is limits the ability to utilize newer, denser, more efficient equipment. Leaving the equipment racks oriented as they are today ensures that we are inefficiently cooling the data centers and spending extra money on power.	Yes	1/1/2025	12/31/2027	$ 1,300,000.50	$ 1,000,000.50	$ 423,015.11	$ 125,418.42	$ 279,999.98		$ 170,267.00	$ -					$ -
85	2025	Digital Worker Experience Electric EOL	Return to Health	Electric	Infrastructure Operations	Steve Ambrose	DPMD001320	Actual	For the years 2023-2025, annually endpoint devices that end of life will need to be replaced to meet the needs of the business users. The current break-down is as follows: Endpoint End of Life (EOL) Device Replacements: Replace approximately 2053 endpoint devices greater than 5 years old. Endpoint New Growth Devices: Business unit new hire growth approximately 7% annually (49 estimate of 700 new hires across the corporation). Mobility Growth Related Devices: Replace a limited number of Non-EOL desktop devices with mobile devices each year due to the changing demands of the workforce responsibilities (i.e. transition from office to field work). Endpoint destruction: Replace 100 units of Non-EOL devices which have been damaged to the point of inoperability or destroyed. Business unit requests for 5 or more devices will be considered project work and outside the scope of this business case due to the hardware and labor costs involved.	Ensures employees are able to complete daily work effort. The outcome of this business case is to refresh older endpoint devices in alignment with the Asset Standard Compliance plan by the end of 2025. Newer devices will improve the employee experience by reducing downtime and improving performance and productivity.	Not Applicable	The introduction of other original equipment manufacturers assets into the endpoint mix would have required a redesign of the secure operating system packages, a distinctive set of patching protocols and the need to increased personal to maintain and sustain the different assets introduced to the workforce. This option was rejected as the investment cost would have increased for every new "non-standard" asset introduced. The alternative considered would be to not refresh these core components, increasing the likelihood of system and personnel downtime, causing interruption to normal business operations, and determined unacceptable to daily operations.	This effort involves replacing physical hardware assets hence no cloud solution is required.	Yes	1/1/2023	12/31/2025	$ 3,594,764.48	$ 3,573,283.86	$ 298,474.31	$ 768,999.74	$ 2,142,211.70	$ -	$ 385,298.00	$ 21,480.53	$ 153.72	$ 708.95	$ 20,599.00			$ 21,480.53
86	2026	Digital Worker Experience Electric EOL	Return to Health	Electric	Infrastructure Operations	Steve Ambrose	DPMD002416	Level 3	For the years 2026-2027, annually endpoint devices that end of life will need to be replaced to meet the needs of the business users. The current break-down is as follows: Endpoint End of Life (EOL) Device Replacements: Replace approximately 5000 endpoint devices greater than 5 years old. Endpoint New Growth Devices: Business unit new hire growth approximately 7% annually (49 estimate of 700 new hires across the corporation). Mobility Growth Related Devices: Replace a limited number of Non-EOL desktop devices with mobile devices each year due to the changing demands of the workforce responsibilities (i.e. transition from office to field work). Endpoint destruction: Replace 100 units of Non-EOL devices which have been damaged to the point of inoperability or destroyed. Business unit requests for 5 or more devices will be considered project work and outside the scope of this business case due to the hardware and labor costs involved.	Ensures employees are able to complete daily work effort. The outcome of this business case is to refresh older endpoint devices in alignment with the Asset Standard Compliance plan by the end of 2027. Newer devices will improve the employee experience by reducing downtime and improving performance and productivity.	Not Applicable	The introduction of other original equipment manufacturers assets into the endpoint mix would have required a redesign of the secure operating system packages, a distinctive set of patching protocols and the need to increased personal to maintain and sustain the different assets introduced to the workforce. This option was rejected as the investment cost would have increased for every new "non-standard" asset introduced. The alternative considered would be to not refresh these core components, increasing the likelihood of system and personnel downtime, causing interruption to normal business operations, and determined unacceptable to daily operations.	This effort involves replacing physical hardware assets hence no cloud solution is required.	Yes	1/1/2026	12/31/2027	$ 2,669,989.62	$ 2,619,989.62	$ 205,962.90	$ 99,999.98	$ 2,098,030.08		$ 215,106.00	$ 50,000.00		$ 50,000.00			$ 50,000.00
87	2027	Digital Worker Experience Electric EOL	Return to Health	Electric	Infrastructure Operations	Steve Ambrose	DPMD002416	Level 3	For the years 2026-2027, annually endpoint devices that end of life will need to be replaced to meet the needs of the business users. The current break-down is as follows: Endpoint End of Life (EOL) Device Replacements: Replace approximately 5000 endpoint devices greater than 5 years old. Endpoint New Growth Devices: Business unit new hire growth approximately 7% annually (49 estimate of 700 new hires across the corporation). Mobility Growth Related Devices: Replace a limited number of Non-EOL desktop devices with mobile devices each year due to the changing demands of the workforce responsibilities (i.e. transition from office to field work). Endpoint destruction: Replace 100 units of Non-EOL devices which have been damaged to the point of inoperability or destroyed. Business unit requests for 5 or more devices will be considered project work and outside the scope of this business case due to the hardware and labor costs involved.	Ensures employees are able to complete daily work effort. The outcome of this business case is to refresh older endpoint devices in alignment with the Asset Standard Compliance plan by the end of 2027. Newer devices will improve the employee experience by reducing downtime and improving performance and productivity.	Not Applicable	The introduction of other original equipment manufacturers assets into the endpoint mix would have required a redesign of the secure operating system packages, a distinctive set of patching protocols and the need to increased personal to maintain and sustain the different assets introduced to the workforce. This option was rejected as the investment cost would have increased for every new "non-standard" asset introduced. The alternative considered would be to not refresh these core components, increasing the likelihood of system and personnel downtime, causing interruption to normal business operations, and determined unacceptable to daily operations.	This effort involves replacing physical hardware assets hence no cloud solution is required.	Yes	1/1/2026	12/31/2027	$ 2,698,989.62	$ 2,648,989.62	$ 200,687.30	$ 100,000.04	$ 2,329,206.48		$ 215,106.00	$ 50,000.00		$ 50,000.00			$ 50,000.00
88	2028	Digital Worker Experience Electric EOL	Return to Health	Electric	Infrastructure Operations	Steve Ambrose	DPMD004305	Level 3	For the years 2028-2029, annually endpoint devices that end of life will need to be replaced to meet the needs of the business users. The current break-down is as follows: Endpoint End of Life (EOL) Device Replacements: Replace approximately 5000 endpoint devices greater than 5 years old. Endpoint New Growth Devices: Business unit new hire growth approximately 7% annually (49 estimate of 700 new hires across the corporation). Mobility Growth Related Devices: Replace a limited number of Non-EOL desktop devices with mobile devices each year due to the changing demands of the workforce responsibilities (i.e. transition from office to field work). Endpoint destruction: Replace 100 units of Non-EOL devices which have been damaged to the point of inoperability or destroyed. Business unit requests for 5 or more devices will be considered project work and outside the scope of this business case due to the hardware and labor costs involved.	Ensures employees are able to complete daily work effort. The outcome of this business case is to refresh older endpoint devices in alignment with the Asset Standard Compliance plan by the end of 2028. Newer devices will improve the employee experience by reducing downtime and improving performance and productivity.	Not Applicable	The introduction of other original equipment manufacturers assets into the endpoint mix would have required a redesign of the secure operating system packages, a distinctive set of patching protocols and the need to increased personal to maintain and sustain the different assets introduced to the workforce. This option was rejected as the investment cost would have increased for every new "non-standard" asset introduced. The alternative considered would be to not refresh these core components, increasing the likelihood of system and personnel downtime, causing interruption to normal business operations, and determined unacceptable to daily operations.	This effort involves replacing physical hardware assets hence no cloud solution is required.	Yes	1/1/2028	12/31/2029	$ 2,701,753.25	$ 2,651,550.50	$ 291,507.56	$ 714,949.98	$ 1,244,500.04		$ 360,743.00	$ 50,202.75	$ 50,202.75				$ 50,202.75
89	2027	End of Life Replacement of Network Equipment supporting Field Communications	Return to Health	Shared	Infrastructure Operations	Steve Ambrose	DPMD003919	Level 3	We have around 250 equipment that is reaching end of life (age or 2027 end of life). These need to be replaced to provide reliable and secure network services to Field Communications a.k.a. Operational Technology Communications and associated application portfolio. FY27 scope: Replace 120 CGS switches and 1 IR8070 LTE switch FY28 scope: Replace 176 CGR switches and 10 ISR4451 switches. FY29 scope: Replace 40 CGR switches A typical life cycle for a network asset can vary anywhere between 7-10 years. After which the vendor stops supporting these assets including providing remediation to bugs and security vulnerabilities. This demand is to constantly keep DTE's network equipment up to date. This will ensure DTE's communication network is able to support the power requirements of the ever changing business requirements and at an appropriate level of service. These requirements constantly change year after year and hence implementing the solution becomes imperative. And if we do not implement on the agreed upon scope, the entire DTE communications can be disrupted with extreme and adverse impact to all DTE operations including grid operations, availability, safety, security etc. These network and telecommunication services are engineered and operated using strategic vendor solutions and platforms including Cisco etc. This project is an ongoing program to replace End Of Life network hardware that is supporting Electric business Field Communication needs and associated application portfolios. These updated solutions will address the components that have reached their end of designed and support life. This will also provide necessary expansions to meet business partner requirements, expectations, and demand.	Customer Experience- DTE's Network and Telecommunication infrastructure is one of the 3 most important infrastructures in DTE. This infrastructure provides reliable and secure Network services to Electric business Field Communications (OT network services) and associated application portfolio. This service is essential and critical to DTE in SAFELY and RELIABLY operating including generating, distributing energy, Customer Service, Crew Safety across our territories. Employee Engagement- DTE's Network and Telecommunication infrastructure is one of the 3 most important infrastructures in DTE. This infrastructure provides reliable and secure Network services to Electric business Field Communications (OT network services) and associated application portfolio. This service is essential and critical to DTE in SAFELY and RELIABLY operating including generating, distributing energy, Customer Service, Crew Safety across our territories. Affordability and Growth- DTE's Network and Telecommunication infrastructure is one of the 3 most important infrastructures in DTE. This infrastructure provides reliable and secure Network services to Electric business Field Communications (OT network services) and associated application portfolio. This service is essential and critical to DTE in SAFELY and RELIABLY operating including generating, distributing energy, Customer Service, Crew Safety across our territories. Operational Reliability- DTE's Network and Telecommunication infrastructure is one of the 3 most important infrastructures in DTE. This infrastructure provides reliable and secure Network services to Electric business Field Communications (OT network services) and associated application portfolio. This service is essential and critical to DTE in SAFELY and RELIABLY operating including generating, distributing energy, Customer Service, Crew Safety across our territories.	1) Do Nothing: This will have a total adverse impact on DTE's network services and consequently to DTE Field Communications (OT network services). The do-nothing alternative would have so not complete the refresh for core components as they reach the serviceable end of life. This was rejected as it would increase system and workforce demand and cause interruption to normal business operations and increase unplanned outages due to network device failures No other alternatives have been considered as DTE has a strategic investment and partnership with these vendors/platforms.	Not Applicable	ompliance Electric (OC) applications including those deployed in Cloud (Storm Cloud), these equipment is in the	Yes	1/1/2027	12/31/2029	$ 2,649,989.84	$ 2,649,989.84	$ 250,000.00		$ 1,225,375.84		$ 274,424.00	$ -					$ -
90	2028	End of Life Replacement of Network Equipment supporting Field Communications	Return to Health	Shared	Infrastructure Operations	Steve Ambrose	DPMD003919	Level 3	We have around 250 equipment that is reaching end of life (age or 2027 end of life). These need to be replaced to provide reliable and secure network services to Field Communications a.k.a. Operational Technology Communications and associated application portfolio. FY27 scope: Replace 120 CGS switches and 1 IR8070 LTE switch FY28 scope: Replace 176 CGR switches and 10 ISR4451 switches. FY29 scope: Replace 40 CGR switches A typical life cycle for a network asset can vary anywhere between 7-10 years. After which the vendor stops supporting these assets including providing remediation to bugs and security vulnerabilities. This demand is to constantly keep DTE's network equipment up to date. This will ensure DTE's communication network is able to support the power requirements of the ever changing business requirements and at an appropriate level of service. These requirements constantly change year after year and hence implementing the solution becomes imperative. And if we do not implement on the agreed upon scope, the entire DTE communications can be disrupted with extreme and adverse impact to all DTE operations including grid operations, availability, safety, security etc. These network and telecommunication services are engineered and operated using strategic vendor solutions and platforms including Cisco etc. This project is an ongoing program to replace End Of Life network hardware that is supporting Electric business Field Communication needs and associated application portfolios. These updated solutions will address the components that have reached their end of designed and support life. This will also provide necessary expansions to meet business partner requirements, expectations, and demand.	Customer Experience- DTE's Network and Telecommunication infrastructure is one of the 3 most important infrastructures in DTE. This infrastructure provides reliable and secure Network services to Electric business Field Communications (OT network services) and associated application portfolio. This service is essential and critical to DTE in SAFELY and RELIABLY operating including generating, distributing energy, Customer Service, Crew Safety across our territories. Employee Engagement- DTE's Network and Telecommunication infrastructure is one of the 3 most important infrastructures in DTE. This infrastructure provides reliable and secure Network services to Electric business Field Communications (OT network services) and associated application portfolio. This service is essential and critical to DTE in SAFELY and RELIABLY operating including generating, distributing energy, Customer Service, Crew Safety across our territories. Affordability and Growth- DTE's Network and Telecommunication infrastructure is one of the 3 most important infrastructures in DTE. This infrastructure provides reliable and secure Network services to Electric business Field Communications (OT network services) and associated application portfolio. This service is essential and critical to DTE in SAFELY and RELIABLY operating including generating, distributing energy, Customer Service, Crew Safety across our territories. Operational Reliability- DTE's Network and Telecommunication infrastructure is one of the 3 most important infrastructures in DTE. This infrastructure provides reliable and secure Network services to Electric business Field Communications (OT network services) and associated application portfolio. This service is essential and critical to DTE in SAFELY and RELIABLY operating including generating, distributing energy, Customer Service, Crew Safety across our territories.	1) Do Nothing: This will have a total adverse impact on DTE's network services and consequently to DTE Field Communications (OT network services). The do-nothing alternative would have so not complete the refresh for core components as they reach the serviceable end of life. This was rejected as it would increase system and workforce demand and cause interruption to normal business operations and increase unplanned outages due to network device failures No other alternatives have been considered as DTE has a strategic investment and partnership with these vendors/platforms.	Not Applicable	ompliance Electric (OC) applications including those deployed in Cloud (Storm Cloud), these equipment is in the	Yes	1/1/2027	12/31/2029	$ 2,349,989.84	$ 2,349,989.84	$ 350,000.00		$ 1,725,375.84		$ 274,424.00	$ -					$ -

91	2025	Endpoint Operating System and Hardware Upgrade	Return-to-Health	Shared	Infrastructure Operations	Steve Ambrose	OHMD0001855	Actual	The demand is to design the corporate vlna The design and testing of 200 of the top DTE Enterprise applications is the CMPI component of the budget go, test it on the top 200 DTE applications, perform a 1,000 device pilot and follow the Windows End-of-Life process/program to update the endpoints. The planned deployment wouldbe in year 1 of 1,200 devices, in the second year 7,000 and in the third year 7,000 devices The capital funding is for the purchase of new Dell laptops/desktops not covered with the current ESS, annual funding as well as the labor to perform the hardware replacements. There is no software purchase that is required for the project. Only Hardware purchase to meet the minimum hardware requirements for the Windows 11 operating system. 3 Year Scope: FY24: Upgrade 1996 endpoints some of which will need to be replaced with Windows 11 compatible devices, FY25: Purchase and/or upgrade 2601 endpoints, FY26: Purchase and/or upgrade 2601 endpoints.	Customer Experience: Qualitative only This is a significant improvement to (internal) customer experience ranging from usability, utise, security improvements Employee Engagement: This will impact around 10,000 machines. As per Microsoft , newer versions of Windows provide a better user experience for PWRRK increase work from anywhere score , employee engagement and productivity increase (https://docs.microsoft.com/en-us/mem/analytics/work-from-anywhere) Microsoft has also reported an impressive 88.8% crash free experience in the Windows 11 preview Affordability and Growth: New enhanced features increase productivity of end users Instantly productive with Windows 11 - "New work can happen whenever & wherever" - Hero start screen redesigns productivity - Optimize screen space and workflow - This aligns with PWRRR strategy, Link for additional details https://www.microsoft.com/en-us/windows/business/windows-11-productivity-features Operational Reliability: Keeping Storm Support endpoints up-to-date is paramount in ensuring that necessary timely support can be provided during system downtimes. Win 10 retirement is 2025 so will need to start in 2024 to convert storm support desktops in 2024 as phase 1 to complete project by Microsoft sunset date in 2025. Storm personnel also support remotely (PWRRR) and reliability of equipment is of high importance. Current state - 0 machines on Windows11, Target State - Around 10,000 machines on Windows11 Foundational Capability: Maintain current versions of OS and Hardware upgrades allows for the capability for future enhancements	None. DTE has adopted the Microsoft platform which directs our operating system selection and support. Therefore it is incumbent that DTE use the most up to date operating systems and hardware requirements to be compliant with the platform.	Not Applicable	This is not a cloud solution or activity.	Yes	1/3/2024	12/22/2026	$ 1,965,571.20	$ 1,773,488.21	$ 116,212.47	$ 612,577.90	$ 755,114.94	$ 78,735.00	$ 232,747.00	$ 192,082.64	$ (449.69)	$ 192,344.05	$ 188.28			$ 198,228.94
92	2026	Endpoint Operating System and Hardware Upgrade	Return-to-Health	Shared	Infrastructure Operations	Steve Ambrose	OHMD0001855	Level 3	The demand is to design the corporate vlna The design and testing of 200 of the top DTE Enterprise applications is the CMPI component of the budget go, test it on the top 200 DTE applications, perform a 1,000 device pilot and follow the Windows End-of-Life process/program to update the endpoints. The planned deployment wouldbe in year 1 of 1,200 devices, in the second year 7,000 and in the third year 7,000 devices The capital funding is for the purchase of new Dell laptops/desktops not covered with the current ESS, annual funding as well as the labor to perform the hardware replacements. There is no software purchase that is required for the project. Only Hardware purchase to meet the minimum hardware requirements for the Windows 11 operating system. 3 Year Scope: FY24: Upgrade 1996 endpoints some of which will need to be replaced with Windows 11 compatible devices, FY25: Purchase and/or upgrade 2601 endpoints, FY26: Purchase and/or upgrade 2601 endpoints.	Customer Experience: Qualitative only This is a significant improvement to (internal) customer experience ranging from usability, utise, security improvements Employee Engagement: This will impact around 10,000 machines. As per Microsoft , newer versions of Windows provide a better user experience for PWRRK increase work from anywhere score , employee engagement and productivity increase (https://docs.microsoft.com/en-us/mem/analytics/work-from-anywhere) Microsoft has also reported an impressive 88.8% crash free experience in the Windows 11 preview Affordability and Growth: New enhanced features increase productivity of end users Instantly productive with Windows 11 - "New work can happen whenever & wherever" - Hero start screen redesigns productivity - Optimize screen space and workflow - This aligns with PWRRR strategy, Link for additional details https://www.microsoft.com/en-us/windows/business/windows-11-productivity-features Operational Reliability: Keeping Storm Support endpoints up-to-date is paramount in ensuring that necessary timely support can be provided during system downtimes. Win 10 retirement is 2025 so will need to start in 2024 to convert storm support desktops in 2024 as phase 1 to complete project by Microsoft sunset date in 2025. Storm personnel also support remotely (PWRRR) and reliability of equipment is of high importance. Current state - 0 machines on Windows11, Target State - Around 10,000 machines on Windows11 Foundational Capability: Maintain current versions of OS and Hardware upgrades allows for the capability for future enhancements	None. DTE has adopted the Microsoft platform which directs our operating system selection and support. Therefore it is incumbent that DTE use the most up to date operating systems and hardware requirements to be compliant with the platform.	Not Applicable	This is not a cloud solution or activity.	Yes	1/3/2024	12/22/2026	$ 2,903,600.03	$ 2,666,066.13	$ 41,680.25	$ 1,086,791.88	$ 1,307,005.00		$ 222,528.00	$ 293,598.00	$ 271,989.00	$ 23,000.00				$ 212,590.33
93	2027	Endpoint Operating System and Hardware Upgrade	Return-to-Health	Shared	Infrastructure Operations	Steve Ambrose	OHMD0002437	Level 3	The design and testing of 200 of the top DTE Enterprise applications is the CMPI component of the budget go, test it on the top 200 DTE applications, perform a 1,000 device pilot and follow the Windows End-of-Life process/program to update the endpoints. The planned deployment wouldbe in year 1 of 1,200 devices, in the second year 7,000 and in the third year 7,000 devices The capital funding is for the purchase of new Dell laptops/desktops not covered with the current ESS, annual funding as well as the labor to perform the hardware replacements. There is no software purchase that is required for the project. Only Hardware purchase to meet the minimum hardware requirements for the Windows 11 operating system. 3 Year Scope: FY25: Upgrade 1996 endpoints some of which will need to be replaced with Windows 11 compatible devices, FY26: Purchase and/or upgrade 2601 endpoints, FY27: Purchase and/or upgrade 1500+ endpoints.	Customer Experience: Qualitative only This is a significant improvement to (internal) customer experience ranging from usability, utise, security improvements Employee Engagement: This will impact around 10,000 machines. As per Microsoft , newer versions of Windows provide a better user experience for PWRRK increase work from anywhere score , employee engagement and productivity increase (https://docs.microsoft.com/en-us/mem/analytics/work-from-anywhere) Microsoft has also reported an impressive 88.8% crash free experience in the Windows 11 preview Affordability and Growth: New enhanced features increase productivity of end users Instantly productive with Windows 11 - "New work can happen whenever & wherever" - Hero start screen redesigns productivity - Optimize screen space and workflow - This aligns with PWRRR strategy, Link for additional details https://www.microsoft.com/en-us/windows/business/windows-11-productivity-features Operational Reliability: Keeping Storm Support endpoints up-to-date is paramount in ensuring that necessary timely support can be provided during system downtimes. Win 10 retirement is 2025 so will need to start in 2024 to convert storm support desktops in 2024 as phase 1 to complete project by Microsoft sunset date in 2025. Storm personnel also support remotely (PWRRR) and reliability of equipment is of high importance. Current state - 0 machines on Windows11, Target State - Around 10,000 machines on Windows11 Foundational Capability: Maintain current versions of OS and Hardware upgrades allows for the capability for future enhancements	None. DTE has adopted the Microsoft platform which directs our operating system selection and support. Therefore it is incumbent that DTE use the most up to date operating systems and hardware requirements to be compliant with the platform.	Not Applicable	This is not a cloud solution or activity.	Yes	1/3/2027	12/22/2028	$ 2,901,260.36	$ 2,690,771.38	$ 49,875.96	$ 326,712.33	$ 2,045,999.96		$ 178,085.00	$ 300,509.65	$ 126,389.61	$ 173,693.00				$ 217,568.86
94	2028	Endpoint Operating System and Hardware Upgrade	Return-to-Health	Shared	Infrastructure Operations	Steve Ambrose	OHMD0002437	Level 3	The design and testing of 200 of the top DTE Enterprise applications is the CMPI component of the budget go, test it on the top 200 DTE applications, perform a 1,000 device pilot and follow the Windows End-of-Life process/program to update the endpoints. The planned deployment wouldbe in year 1 of 1,200 devices, in the second year 7,000 and in the third year 7,000 devices The capital funding is for the purchase of new Dell laptops/desktops not covered with the current ESS, annual funding as well as the labor to perform the hardware replacements. There is no software purchase that is required for the project. Only Hardware purchase to meet the minimum hardware requirements for the Windows 11 operating system. 3 Year Scope: FY26: Upgrade 1996 endpoints some of which will need to be replaced with Windows 11 compatible devices, FY28: Purchase and/or upgrade 2601 endpoints, FY27: Purchase and/or upgrade 1500+ endpoints.	Customer Experience: Qualitative only This is a significant improvement to (internal) customer experience ranging from usability, utise, security improvements Employee Engagement: This will impact around 10,000 machines. As per Microsoft , newer versions of Windows provide a better user experience for PWRRK increase work from anywhere score , employee engagement and productivity increase (https://docs.microsoft.com/en-us/mem/analytics/work-from-anywhere) Microsoft has also reported an impressive 88.8% crash free experience in the Windows 11 preview Affordability and Growth: New enhanced features increase productivity of end users Instantly productive with Windows 11 - "New work can happen whenever & wherever" - Hero start screen redesigns productivity - Optimize screen space and workflow - This aligns with PWRRR strategy, Link for additional details https://www.microsoft.com/en-us/windows/business/windows-11-productivity-features Operational Reliability: Keeping Storm Support endpoints up-to-date is paramount in ensuring that necessary timely support can be provided during system downtimes. Win 10 retirement is 2025 so will need to start in 2024 to convert storm support desktops in 2024 as phase 1 to complete project by Microsoft sunset date in 2025. Storm personnel also support remotely (PWRRR) and reliability of equipment is of high importance. Current state - 0 machines on Windows11, Target State - Around 10,000 machines on Windows11 Foundational Capability: Maintain current versions of OS and Hardware upgrades allows for the capability for future enhancements	None. DTE has adopted the Microsoft platform which directs our operating system selection and support. Therefore it is incumbent that DTE use the most up to date operating systems and hardware requirements to be compliant with the platform.	Not Applicable	This is not a cloud solution or activity.	Yes	1/3/2027	12/22/2028	$ 2,901,367.14	$ 2,690,945.15	$ 46,748.00	$ 323,112.11	$ 2,053,000.04		$ 178,085.00	$ 300,421.99	$ 123,021.99	$ 177,400.00				$ 217,605.92
95	2025	Field Worker Device End Of Life	Return-to-Health	Shared	Infrastructure Operations	Steve Ambrose	OHMD0002889	Actual	The recommended solution is to establish and fund an annual replacement cycle for MDT's. In 2024, 250 Mobile Data Terminals will be procured, installed and implemented. In 2025, 250 Mobile Data Terminals will be procured, installed and implemented. In 2026, 250 Mobile Data Terminals will be procured, installed and implemented. MDTs are used by both Gas and Electric field staff and hence this is a shared asset.	This effort provides DTE field crews with technology that provides the ability to reliably address customer issues, react to line downs during storms, prevent safety incidents and communicate effectively with systems and leadership.	Do nothing: This will continue to impact operational excellence and the ability to respond to customer issues during field operations including storms.	Not Applicable	This is a one-to-one replacement of MDT's and would not require cloud usage.	Yes	1/1/2024	12/31/2026	$ 300,815.00	$ 398,819.64	$ 45,062.20	$ 227,396.28	$ 56,685.00	$ -	$ 64,471.00	$ -	$ -					$ -
96	2026	Field Worker Device End Of Life	Return-to-Health	Shared	Infrastructure Operations	Steve Ambrose	OHMD0002889	Level 3	Approved in U-21080																					
97	2027	Field Worker Device End Of Life	Return-to-Health	Electric	Infrastructure Operations	Steve Ambrose	OHMD0004186	Level 3	The recommended solution is a phased replacement strategy will be implemented, ensuring continuity of operations, reducing financial impact, and maintaining service reliability. For this Demand: 2027, 300 Mobile Data Terminals w/docks will be procured, installed and implemented. Future Demands: 2028 - 300 Mobile Data Terminals w/docks will be procured, installed and implemented. 2029 - The initiative will have progressed according to the above plan. 2029 will follow with a maintenance strategy that replaces one-fifth of the fleet annually. Given the current five-year lifecycle and the approximately 1,200 Electric MDT fleet, this approach will require the procurement of 300 Mobile Data Terminals each year.	This effort provides DTE field crews with technology that provides the ability to reliably address customer issues, react to line downs during storms, prevent safety incidents and communicate effectively with systems and leadership.	Do nothing: This will continue to impact operational excellence and the ability to respond to customer issues during field operations including storm restoration.	Not Applicable	This is a one-to-one replacement for MDT's and would not require cloud usage.	Yes	1/1/2027	12/31/2027	$ 2,036,219.26	$ 2,036,219.26	$ 30,250.00	$ 409,500.00	$ 1,465,964.26		$ 130,505.00	$ -						$ -
98	2028	Field Worker Device End Of Life	Return-to-Health	Electric	Infrastructure Operations	Steve Ambrose	OHMD0004186	Level 3	The recommended solution is a phased replacement strategy will be implemented, ensuring continuity of operations, reducing financial impact, and maintaining service reliability. For this Demand: 2027, 300 Mobile Data Terminals w/docks will be procured, installed and implemented. Future Demands: 2028 - 300 Mobile Data Terminals w/docks will be procured, installed and implemented. 2029 - The initiative will have progressed according to the above plan. 2029 will follow with a maintenance strategy that replaces one-fifth of the fleet annually. Given the current five-year lifecycle and the approximately 1,200 Electric MDT fleet, this approach will require the procurement of 300 Mobile Data Terminals each year.	This effort provides DTE field crews with technology that provides the ability to reliably address customer issues, react to line downs during storms, prevent safety incidents and communicate effectively with systems and leadership.	Do nothing: This will continue to impact operational excellence and the ability to respond to customer issues during field operations including storm restoration.	Not Applicable	This is a one-to-one replacement for MDT's and would not require cloud usage.	Yes	1/1/2028	12/31/2028	$ 2,200,776.68	$ 2,200,776.68	$ 30,250.00	$ 486,500.00	$ 1,717,290.00		$ 140,826.00	$ -						$ -
99	2025	IT Infrastructure EOL Asset Replacement	Return-to-Health	Shared	Infrastructure Operations	Steve Ambrose	OHMD0002133	Actual	The EOL Asset Replacement project will replace servers, storage, databases, and operating licenses that are at end of their serviceable life which means they are no longer capable of accepting operating system or security upgrades, capacity has reached the upper threshold of processing ability, or the technology will no longer interact with newer components within the architecture. These assets located within our corporate data centers or major secondary sites are reliant upon continuous upgrades to ensure that security, capacity, or operating parameters are capable of meeting business requirements	Provides a normalized environment for the business applications and ensures business demands are met without extraordinary effort. This business case will fund the installation and configuration of new hardware and software environments in the data center to improve our overall risk exposure. To be replaced include: IT Assets (Servers, Storage, DB, and PKI components) that are beyond asset life cycle threshold and in danger of not being supported by corresponding OEM vendors.	The do nothing alternative was rejected as assets would have the potential for increased outages and interruptions of service would increase by 10% based on evaluation of standards from the National Institute of Standards and Technology.	Not Applicable	The project involves end of life hardware assets for EDSD and hence, no cloud solution required for this effort	Yes	1/1/2023	12/31/2025	$ 825,790.00	$ 825,790.19	$ 32,132.40	$ 422,928.63	$ 14,187.02	$ 39,132.24	$ 67,381.00	$ -	$ -					$ -
100	2026	IT Infrastructure EOL Asset Replacement	Return-to-Health	Shared	Infrastructure Operations	Steve Ambrose	OHMD0002463	Level 3	Approved in U-21080																					
101	2027	IT Infrastructure EOL Asset Replacement	Return-to-Health	Shared	Infrastructure Operations	Steve Ambrose	OHMD0002463	Level 3	This is a year-over year demand. The scope for each year depends on business requirements and prioritization. This includes end of life servers, storages and databases. For 2026, DTE would be replacing an estimated 25% of its assets that has reached end of life. Additionally, DTE would also procure software such as printing systems, scheduling software etc. based on business priorities. This approach would continue for 2027 as well. Scope for 2027: Vendor support from Dell and Brocade can for these servers is scheduled to reach end of life in FY27. So, all VMware hosts and Brocade SAN switches will reach end of life and need to be replaced in 2027 and beyond. Instead, it must be completed as a large, one-time upgrade, which has now been pulled ahead into 2027. The EOL Asset Replacement project will replace servers, storage, databases, and operating licenses that are at end of their serviceable life which means they are no longer capable of accepting operating system or security upgrades, capacity has reached the upper threshold of processing ability, or the technology will no longer interact with newer components within the architecture. These assets located within our corporate data centers or major secondary sites are reliant upon continuous upgrades to ensure that security, capacity, or operating parameters are capable of meeting business requirements	Provides a normalized environment for the business applications and ensures business demands are met without extraordinary effort. This business case will fund the installation and configuration of new hardware and software environments in the data center to improve our overall risk exposure. To be replaced include: IT Assets (Servers, Storage, DB, and PKI components) that are beyond asset life cycle threshold and in danger of not being supported by corresponding OEM vendors.	The do nothing alternative was rejected as assets would have the potential for increased outages and interruptions of service would increase by 10% based on evaluation of standards from the National Institute of Standards and Technology.	Not Applicable	The project involves end of life hardware assets for EDSD and hence, no cloud solution required for this effort	Yes	1/1/2026	12/31/2027	$ 1,000,695.48	$ 1,000,695.48	$ 48,042.48	$ 64,300.00	$ 544,713.72	$ 229,191.28	$ 97,753.00	$ -						$ -
102	2028	IT Infrastructure EOL Asset Replacement	Return-to-Health	Shared	Infrastructure Operations	Steve Ambrose	OHMD0004210	Level 3	This is a year-over year demand. The scope for each year depends on business requirements and prioritization. This includes end of life servers, storages and databases. For 2028, DTE would be replacing an estimated 25% of its assets that has reached end of life. Additionally, DTE would also procure software such as printing systems, scheduling software etc. based on business priorities. This approach would continue for 2028 as well. The EOL Asset Replacement project will replace servers, storage, databases, and operating licenses that are at end of their serviceable life which means they are no longer capable of accepting operating system or security upgrades, capacity has reached the upper threshold of processing ability, or the technology will no longer interact with newer components within the architecture. These assets located within our corporate data centers or major secondary sites are reliant upon continuous upgrades to ensure that security, capacity, or operating parameters are capable of meeting business requirements	Provides a normalized environment for the business applications and ensures business demands are met without extraordinary effort. This business case will fund the installation and configuration of new hardware and software environments in the data center to improve our overall risk exposure. To be replaced include: IT Assets (Servers, Storage, DB, and PKI components) that are beyond asset life cycle threshold and in danger of not being supported by corresponding OEM vendors.	The do nothing alternative was rejected as assets would have the potential for increased outages and interruptions of service would increase by 10% based on evaluation of standards from the National Institute of Standards and Technology.	Not Applicable	The project involves end of life hardware assets for EDSD and hence, no cloud solution required for this effort	Yes	1/1/2028	12/31/2028	$ 1,010,091.24	$ 1,010,091.24	$ 117,374.24	$ 182,669.00	$ 282,048.00	$ 298,000.00	$ 122,711.00	$ -	$ -					$ -
103	2025	Load Balancer Asset Health and Re-Engineering	Return-to-Health	Shared	Infrastructure Operations	Steve Ambrose	OHMD0002421	Actual	Approved in U-21080																					
104	2026	Load Balancer Asset Health and Re-Engineering	Return-to-Health	Shared	Infrastructure Operations	Steve Ambrose	OHMD0002421	Level 3	Approved in U-21080																					
105	2025	Modernize Disaster Recovery Tools	Return-to-Health	Shared	Infrastructure Operations	Steve Ambrose	OHMD0002534	Actual	Approved in U-21080																					
106	2027	Network EOL Support - SOC Operations	Return-to-Health	Electric	Infrastructure Operations	Steve Ambrose	OHMD0002818	Level 3	These network and telecommunication services are engineered and operated using strategic vendor solutions and platforms including Cisco etc. This project is an ongoing program to replace End Of Life network hardware that is supporting SOC operations and associated application portfolio including EMS, DMS, ADMS etc. These updated solutions will address the components that have reached their end of designed and serviceable life, as well as provide additional network expansions to meet business partner requirements, expectations, and demand. As devices go end-of-life, this demand aims at replacing that hardware assets at those junctures. We have 18 switches that have been serving us for over 7 years and will reach end of life later in 2028. These switches need to be replaced to provide reliable and secure Network services to SOC operations and associated application portfolio including EMS, DMS, ADMS etc.	The replacement of switches supporting SOC operations would ensure continuous operation reliability to provide network services to portfolio applications including EMS, DMS, ADMS thus serving DTE's internal customers. Additionally, DTE would be able to ascertain operational excellence by executing timely replacement of these switches and can avoid unplanned network outages.	The do nothing alternative would have us not complete the refresh for core components as they reach the serviceable end of life. This was rejected as it would increase system and workforce demand and cause interruption to normal business operations and increase unplanned outages due to network device failures. No other alternatives have been considered as DTE has a strategic investment and partnership with these vendors/platforms.	Not Applicable	compliance SOC applications including those deployed in Cloud (Storm Cloud), these switches are in Compliance	Yes	1/1/2027	12/31/2028	$ 398,838.00	$ 398,838.00	$ 19,770.00		$ 350,000.00		$ 31,065.00	$ -						$ -
107	2028	Network EOL Support - SOC Operations	Return-to-Health	Electric	Infrastructure Operations	Steve Ambrose	OHMD0004287	Level 3	These network and telecommunication services are engineered and operated using strategic vendor solutions and platforms including Cisco etc. This project is an ongoing program to replace End Of Life network hardware that is supporting SOC operations and associated application portfolio including EMS, DMS, ADMS etc. These updated solutions will address the components that have reached their end of designed and serviceable life, as well as provide additional network expansions to meet business partner requirements, expectations, and demand. As devices go end-of-life, this demand aims at replacing that hardware assets at those junctures. We have TBD switches that have been serving us for over 7 years and will reach end of life later in 2028. These switches need to be replaced to provide reliable and secure Network services to SOC operations and associated application portfolio including EMS, DMS, ADMS etc.	The replacement of switches supporting SOC operations would ensure continuous operation reliability to provide network services to portfolio applications including EMS, DMS, ADMS thus serving DTE's internal customers. Additionally, DTE would be able to ascertain operational excellence by executing timely replacement of these switches and can avoid unplanned network outages.	The do nothing alternative would have us not complete the refresh for core components as they reach the serviceable end of life. This was rejected as it would increase system and workforce demand and cause interruption to normal business operations and increase unplanned outages due to network device failures. No other alternatives have been considered as DTE has a strategic investment and partnership with these vendors/platforms.	Not Applicable	compliance SOC applications including those deployed in Cloud (Storm Cloud), these switches are in Compliance	Yes	1/1/2028	12/31/2028	$ 400,288.92	$ 400,288.92	$ 52,038.00		$ 294,008.92		$ 54,250.00	$ -						$ -
108	2027	Network Security End of Life Asset Replacement	Return-to-Health	Shared	Infrastructure Operations	Steve Ambrose	OHMD0004103	Level 3	The recommended solution will include the implementing of a multi-year 2027 - 2028 hardware procurement schedule in order to upgrade these hardware assets in or approaching End of Life (EOL). The recommended solution plan is to procure and replace hardware assets	Improved employee and customer experience - Security firmware being kept up to date reduces outages related to vulnerabilities and operational issues. Consistent, secure, continual uptime and access to DTE network. Protection of customer, employee and corporate data: Strengthening network security to avoid exploitation of vulnerabilities.	A 'do nothing' alternative is not acceptable as unmitigated cyber risks could lead to serious cyber incidents with financial and data loss implications.	Not Applicable	Environment is not cloud based.	Yes	1/1/2027	12/31/2028	$ 1,542,565.64	$ 1,542,565.64	$ 23,716.90		$ 942,859.64		$ 76,190.00	$ -						$ -
109	2028	Network Security End of Life Asset Replacement	Return-to-Health	Shared	Infrastructure Operations	Steve Ambrose	OHMD0004103	Level 3	The recommended solution will include the implementing of a multi-year 2027 - 2028 hardware procurement schedule in order to upgrade these hardware assets in or approaching End of Life (EOL). The recommended solution plan is to procure and replace hardware assets	Improved employee and customer experience - Security firmware being kept up to date reduces outages related to vulnerabilities and operational issues. Consistent, secure, continual uptime and access to DTE network. Protection of customer, employee and corporate data: Strengthening network security to avoid exploitation of vulnerabilities.	A 'do nothing' alternative is not acceptable as unmitigated cyber risks could lead to serious cyber incidents with financial and data loss implications.	Not Applicable	Environment is not cloud based.	Yes	1/1/2027	12/31/2028	$ 1,541,980.58	$ 1,541,980.58	$ 23,111.00		$ 942,859.58		$ 76,190.00	$ -						$ -
110	2026	Network UPS End of Life Replacement and Business Continuity	Return-to-Health	Shared	Infrastructure Operations	Steve Ambrose	OHMD0004436	Level 3	The recommended solution is as follows: 2026 - 2027: Procurement of vendor services to utilize UPS as a service to provide a reliable network connectivity for DTE's end users. This includes monitoring, repairs, maintenance and deployment of UPSs over a period of 2 years. The replacement cycle is based on the end-of-life criteria of DTE's UPSs. Access PR is the vendor that currently provides one with our Verizon solutions that provides DC power and battery backup to our devices within power plants and substations as well as our data circuits today. Scope for 2026: will be the installation of appliance hardware to monitor existing fleet of UPS devices within the enterprise. Identifying necessary upgrades to UPS devices for supportability. As well as continual monitor and replacement of covered devices deployed. First round of site visits and maintenance activities to ensure health of critical UPS devices. Inventory and document UPS systems to enter into system for monitoring, maintenance and service. Scope for 2027: will be continued monitoring and replacement of listed devices. Continued onsite maintenance activities and servicing of covered devices in contract.	DTE's UPSs is providing power to network infrastructure including telephones, wifi, computers etc. These networks are critical to maintain DTE's connectivity with both internal and external customers. UPS failure causes the telecom closets to fail with them and this affects the operation of the telecom equipment. These closets not only support DTE's internal customers but also affects DTE's ability to generate electricity and gas distribution.	Do nothing: DTE would risk losing network connectivity due to power failure caused by UPSs and this in turn would impact DTE's ability to provide reliable connectivity to both its internal and external customers.	Not Applicable	This effort is to support on-prem network infrastructure and does not require cloud solution.	No	1/1/2026	12/31/2027	$ 470,030.12	$ 470,030.12	$ 18,905.00	$ 420,785.65			$ 30,311.00	$ -						$ -
111	2027	Network UPS End of Life Replacement and Business Continuity	Return-to-Health	Shared	Infrastructure Operations	Steve Ambrose	OHMD0004436	Level 3	The recommended solution is as follows: 2026 - 2027: Procurement of vendor services to utilize UPS as a service to provide a reliable network connectivity for DTE's end users. This includes monitoring, repairs, maintenance and deployment of UPSs over a period of 2 years. The replacement cycle is based on the end-of-life criteria of DTE's UPSs. Access PR is the vendor that currently provides one with our Verizon solutions that provides DC power and battery backup to our devices within power plants and substations as well as our data circuits today. Scope for 2026: will be the installation of appliance hardware to monitor existing fleet of UPS devices within the enterprise. Identifying necessary upgrades to UPS devices for supportability. As well as continual monitor and replacement of covered devices deployed. First round of site visits and maintenance activities to ensure health of critical UPS devices. Inventory and document UPS systems to enter into system for monitoring, maintenance and service. Scope for 2027: will be continued monitoring and replacement of listed devices. Continued onsite maintenance activities and servicing of covered devices in contract.	DTE's UPSs is providing power to network infrastructure including telephones, wifi, computers etc. These networks are critical to maintain DTE's connectivity with both internal and external customers. UPS failure causes the telecom closets to fail with them and this affects the operation of the telecom equipment. These closets not only support DTE's internal customers but also affects DTE's ability to generate electricity and gas distribution.	Do nothing: DTE would risk losing network connectivity due to power failure caused by UPSs and this in turn would impact DTE's ability to provide reliable connectivity to both its internal and external customers.	Not Applicable	This effort is to support on-prem network infrastructure and does not require cloud solution.	No	1/1/2026	12/31/2027	$ 191,014.33	$ 187,000.28	$ 18,905.00	$ 137,765.50			$ 30,311.00	$ 4,013.75	$ 4,013.75					$ 2,003.38
112	2028	Network UPS End of Life Replacement and Business Continuity	Return-to-Health	Shared	Infrastructure Operations	Steve Ambrose	OHMD0004250	Level 3	The recommended solution is as follows: 2026 - 2029: Procurement of vendor services to utilize UPS as a service to provide a reliable network connectivity for DTE's end users. This includes monitoring, repairs, maintenance and deployment of UPSs over a period of 2 years. The replacement cycle is based on the end-of-life criteria of DTE's UPSs. Access PR is the vendor that currently provides one with our Verizon solutions that provides DC power and battery backup to our devices within power plants and substations as well as our data circuits today. Scope for 2026: will be continued monitoring and replacement of listed devices. Continued onsite maintenance activities and servicing of covered devices in contract.	DTE's UPSs is providing power to network infrastructure including telephones, wifi, computers etc. These networks are critical to maintain DTE's connectivity with both internal and external customers. UPS failure causes the telecom closets to fail with them and this affects the operation of the telecom equipment. These closets not only support DTE's internal customers but also affects DTE's ability to generate electricity and gas distribution.	Do nothing: DTE would risk losing network connectivity due to power failure caused by UPSs and this in turn would impact DTE's ability to provide reliable connectivity to both its internal and external customers.	Not Applicable	This effort is to support on-prem network infrastructure and does not require cloud solution.	No	1/1/2028	12/31/2028	$ 178,799.24	$ 178,799.24	$ 940.24	$ 167,943.00			$ 9,824.00	$ -						$ -
113	2025	Replace Data Center End of Life Network Infrastructure	Return-to-Health	Shared	Infrastructure Operations	Steve Ambrose	OHMD0001331	Actual	Approved in U-21080																					
114	2026	Replace Data Center End of Life Network Infrastructure	Return-to-Health	Shared	Infrastructure Operations	Steve Ambrose	OHMD0002455	Level 3	This on-going effort (2019 - 2027) will improve asset health by replacing end-of-life devices such as data-center core switches and routers and include installation of new components to increase the connection bandwidth between the data centers, thus ensuring more reliable, robust and secure networks. This effort requires constant focus and investment to keep data center networks in compliance with DTE needs Every year a portion of DTE's data center network assets go end of life which requires replacement. A typical life cycle for a network asset can vary anywhere between 7-10 years. After which the vendor stops supporting these assets including providing remediation to bugs and security vulnerabilities. Up to 2025, DTE has around 32 devices going end of support (EOL). Some of these devices may be replaced in 2026 or 2027. In 2028, DTE has around 6 devices going end of life. Similarly in 2027, DTE has 2 devices going end of life in that year. The exact scope of device replacements in 2028 and 2027 depends on how many of these 40 devices gets remediated/replaced up to that particular year (2025, 2026, 2027).	Ensures that the work demand of the business meets their requirements for the processing of user enterprise data transference. This effort will improve asset health by replacing end of life devices in order to ensure security and capability. Thus ensuring more reoliable, robust and secure networks.	As far as 'do nothing' option is considered, it is unstable in Core and Critical networks like Data Center, since a failure would bring down DTE functions. So it has been rejected As far as 'other vendor alternatives' are considered, while it is possible, it is prohibitively expensive (adding a CPI/Relation rate of 3%) estimating around 12.5 million. We can embark on replacing the vendor if there is a strong case for it where the benefit outweighs the cost	Not Applicable	pci involves continued implementation of DTE microwave hardware and hence, no cloud solution required for th	Yes	1/1/2026	12/31/2027	$ 554,365.17	$ 449,998.16	$ 90,810.50	$ 271,288.08			$ 87,790.00	$ 104,363.81	$ 103,163.61	$ 1,200.00				$ 75,559.49
115	2027	Replace Data Center End of Life Network Infrastructure	Return-to-Health	Shared	Infrastructure Operations	Steve Ambrose	OHMD0002455	Level 3	This on-going effort (2019 - 2027) will improve asset health by replacing end-of-life devices such as data-center core switches and routers and include installation of new components to increase the connection bandwidth between the data centers, thus ensuring more reliable, robust and secure networks. This effort requires constant focus and investment to keep data center networks in compliance with DTE needs Every year a portion of DTE's data center network assets go end of life which requires replacement. A typical life cycle for a network asset can vary anywhere between 7-10 years. After which the vendor stops supporting these assets including providing remediation to bugs and security vulnerabilities. Up to 2025, DTE has around 32 devices going end of support (EOL). Some of these devices may be replaced in 2026 or 2027. In 2028, DTE has around 6 devices going end of life. Similarly in 2027, DTE has 2 devices going end of life in that year. The exact scope of device replacements in 2028 and 2027 depends on how many of these 40 devices gets remediated/replaced up to that particular year (2025, 2026, 2027).	Ensures that the work demand of the business meets their requirements for the processing of user enterprise data transference. This effort will improve asset health by replacing end of life devices in order to ensure security and capability. Thus ensuring more reoliable, robust and secure networks.	As far as 'do nothing' option is considered, it is unstable in Core and Critical networks like Data Center, since a failure would bring down DTE functions. So it has been rejected As far as 'other vendor alternatives' are considered, while it is possible, it is prohibitively expensive (adding a CPI/Relation rate of 3%) estimating around 12.5 million. We can embark on replacing the vendor if there is a strong case for it where the benefit outweighs the cost	Not Applicable	pci involves continued implementation of DTE microwave hardware and hence, no cloud solution required for th	Yes	1/1/2026	12/31/2027	$ 552,865.67	$ 450,030.48	$ 90,684.50	$ 271,519.08			$ 87,791.00	$ 102,885.19	$ 102,085.19	$ 800.00				$ 74,488.98
116	2028	Replace Data Center End of Life Network Infrastructure	Return-to-Health	Shared	Infrastructure Operations	Steve Ambrose	OHMD0004211	Level 3	This on-going effort (2028 - 2029) will improve asset health by replacing end-of-life devices such as data-center core switches and routers and include installation of new components to increase the connection bandwidth between the data centers, thus ensuring more reliable, robust and secure networks. This effort requires constant focus and investment to keep data center networks in compliance with DTE needs Every year a portion of DTE's data center network assets go end of life which requires replacement. A typical life cycle for a network asset can vary anywhere between 7-10 years. After which the vendor stops supporting these assets including providing remediation to bugs and security vulnerabilities. Up to 2025, DTE has around 32 devices going end of support (EOL). Some of these devices may be replaced in 2026 or 2028. In 2028, DTE has around 6

120	2028	Replace End of Life Microwave Infrastructure	Return to Health	Shared	Infrastructure Operations	Steve Ambrose	OHMD0004200	Level 3	This continued implementation of the DTE Microwave Infrastructure provides the hardware, configuration and sustainment of higher network speeds and more efficient transmission of data, voice, and video for DTE offices in Service Centers, Power Plants, and key operational facilities. This project is a continuation of the DTE Microwave Project. The DTE Microwave project efforts through the replacement of 2 licensed critical paths and unlicensed paths. Implementation of these replacement paths will improve quality of service, reliability, and allow the Company to release our 4 leased telecom services and replace it with privately owned communications. This investment includes replacement of microwave paths, 20 improvements to stabilize the microwave ring, and support changes mandated by 21 the FCC in deregulation of the 6 gigahertz (GHz) frequency. The FCC has opened the 6GHz frequency spectrum for unlicensed use. The 6GHz devices will be a cause of concern if we do not upgrade to 11GHz through this demand. The recommend solution is to maintain current manufacturer and utilize their 11GHz product. The Microwave system carries our PBX, PCN, SCADA and ARP traffic in our northwest and northeast regions where cellular are bad due to distance and carrier backhaul is expensive as the infrastructure is limited and costly for DTE to have built out. The Microwave system helps us with our backhaul.	Provides fully capable devices and networks for internal requirements that support our customer base. This continued implementation of the DTE Microwave Infrastructure provides the hardware, configuration and sustainment of higher network speeds and more efficient transmission of data, voice, and video for DTE offices in Service Centers, Power Plants, and key operational facilities.	Annually, alternatives are considered based upon improvements to hardware assets and customer driven demand and refined against impact to financial commitments and operational requirements. Failure to make the investment occurs, the end of life systems will fail and disrupt network service to service centers, substations, power plants and other critical locations. Do Nothing: The company rejected a "do nothing" alternative as it would increase the probability of failure of critical telecommunications assets that are required, mandated by the FCC, and delay our ability to release telecom services.	Not Applicable	project involves continued implementation of DTE microwave hardware and hence, no cloud solution required for th	Yes	1/2/2028	12/31/2028	$ 407,788.00	$ 400,012.00	$ 92,106.00		$ 291,280.00		$ 58,628.00	$ 7,776.00	$ 7,776.00					$ 5,829.82
121	2025	Replace End Of Life Network Infrastructure	Return to Health	Electric	Infrastructure Operations	Steve Ambrose	OHMD0001102	Actual	Approved in U-21460																			
122	2026	Replace End Of Life Network Infrastructure	Return to Health	Electric	Infrastructure Operations	Steve Ambrose	OHMD0001458	Level 3	Approved in U-21460																			
123	2027	Replace End Of Life Network Infrastructure	Return to Health	Electric	Infrastructure Operations	Steve Ambrose	OHMD0001458	Level 3	This project is an ongoing program (2018 - 2027) to replace End Of Life network hardware that is not physically secured in either of the corporate data centers. These optimal solutions will address the components that have reached their end of designed and service life, as well as provide additional network expansions to meet business partner requirements, expectations, and demand. As devices go end-of-life every year, this demand aims at replacing that hardware assets every year.	Ensures that the work demand of the business meets their requirements for the processing of user enterprise data transference.	The do-nothing alternative would have un-net complete the refresh for core components as they reach the serviceable end of life. This was rejected as it would increase system and workforce demand and cause interruption to normal business operations and increase unplanned outages due to network device failures.	Not Applicable	This project involves replacing end of life network assets, therefore no cloud solution is required for this effort.	Yes	1/2/2026	12/31/2027	$ 800,007.98	$ 795,192.48	$ 244,512.50		$ 256,990.96		$ 198,679.00	$ 98,815.50	$ 98,815.50					$ 99,815.50
124	2028	Replace End Of Life Network Infrastructure	Return to Health	Electric	Infrastructure Operations	Steve Ambrose	OHMD0004212	Level 3	This project is an ongoing program to replace End Of Life network hardware that is not physically secured in either of the corporate data centers. These optimal solutions will address the components that have reached their end of designed and service life, as well as provide additional network expansions to meet business partner requirements, expectations, and demand. As devices go end-of-life every year, this demand aims at replacing that hardware assets every year.	Ensures that the work demand of the business meets their requirements for the processing of user enterprise data transference.	The do-nothing alternative would have un-net complete the refresh for core components as they reach the serviceable end of life. This was rejected as it would increase system and workforce demand and cause interruption to normal business operations and increase unplanned outages due to network device failures.	Not Applicable	This project involves replacing end of life network assets, therefore no cloud solution is required for this effort.	Yes	1/2/2028	12/31/2028	$ 836,541.39	$ 735,885.54	$ 244,139.50		$ 257,000.64		$ 234,746.00	$ 105,455.75	$ 105,455.75					$ 105,455.75
125	2025	Security Infrastructure Growth and EOL	Return to Health	Shared	Infrastructure Operations	Steve Ambrose	OHMD0004235	Actual	Improved employee and customer experience - Security firmware being kept up to date reduces outages related to vulnerabilities and operational issues. Protection of customer, employee and corporate data: Avoid exploitation of vulnerabilities by patching the security infrastructure. Delivered in 2025: Replaced INET 5401's with Dell's, Conduct Annual CHG Upgrades Implemented MCHAS HIT Add 2 Trapeze Controllers, Add 2 Cisco ISE nodes to 2 DR/servers Upgraded/Net replaced, all active network security devices (e.g., DNS, Firewall, Proxy, etc. Includes CSI, Iscilians, etc.)	Improved employee and customer experience - Security firmware being kept up to date reduces outages related to vulnerabilities and operational issues. Protection of customer, employee and corporate data: Avoid exploitation of vulnerabilities by patching the security infrastructure.	A 'do-nothing' alternative is not acceptable as unmitigated cyber risks could lead to serious cyber incidents with financial and data loss implications.	Not Applicable	Environment is not cloud based.	Yes	1/2/2023	12/31/2025	$ 1,398,799.55	$ 1,398,799.07	$ 254,216.57	$ 417,889.50	$ 296,757.19	$ 869,128.81	$ 229,907.50	$ -	$ -			$ -
126	2026	Security Infrastructure Growth and EOL	Return to Health	Shared	Infrastructure Operations	Steve Ambrose	OHMD0004369	Level 3	Approved in U-21460																			
127	2027	Security Infrastructure Growth and EOL	Return to Health	Shared	Infrastructure Operations	Steve Ambrose	OHMD0004499	Level 3	The recommended solution will depend upon the specific asset. Options include upgrading firmware, upgrading hardware, expanding capacity to meet increased demand, or replacing the technology. NetSec will replace the hardware as well as update the firmware to keep the assets healthy. Below are the appliances and functionality that are in-scope for 2026: Network Firewalls: Protects the DTE network from external as well as internal threats. Ensures only approved network traffic from known sources can communicate with DTE's applications and digital assets. Remote Access Appliances: These appliances provide the ability for DTE employees and vendors to securely connect to DTE systems and applications. Internal Certificate Management System: This system is used to issue digital certificates required for secure network communication as well as authentication for servers and endpoint devices. Secure File Transfer: This system is dedicated to enable DTE to securely exchange data with external entities to support business processes. Following is the scope of 2027: Web Proxy Appliances: Provides protection for DTE users and servers communicating to the external websites. It prevents endpoint devices and servers from being exploited by risky websites. Network Firewalls: Protects the DTE network from external as well as internal threats. Ensures only approved network traffic from known sources can communicate with DTE's applications and digital assets. External Domain Name System: These appliances provide the capability of connecting Uniform Resource Locator (URL) address of a web page/ requests for DTE applications into specific network addresses so these applications could be accessed from the internet. Virtual Private Network (VPN) Software: This software enables the DTE laptops to securely connect to DTE's network, which is	Improved employee and customer experience - Security firmware being kept up to date reduces outages related to vulnerabilities and operational issues. Protection of customer, employee and corporate data: Avoid exploitation of vulnerabilities by patching the security infrastructure.	A 'do-nothing' alternative is not acceptable as unmitigated cyber risks could lead to serious cyber incidents with financial and data loss implications.	Not Applicable	Environment is not cloud based.	Yes	1/2/2026	12/31/2027	$ 1,412,655.49	$ 1,412,655.49	$ 264,844.49		$ 901,000.00		$ 246,711.00	$ -	$ -			$ -
128	2028	Security Infrastructure Growth and EOL	Return to Health	Shared	Infrastructure Operations	Steve Ambrose	OHMD0004214	Level 3	The recommended solution will depend upon the specific asset. Options include upgrading firmware, upgrading hardware, expanding capacity to meet increased demand, or replacing the technology. NetSec will replace the hardware as well as update the firmware to keep the assets healthy. Below are the appliances and functionality that are in-scope for 2028: Network Firewalls: Protects the DTE network from external as well as internal threats. Ensures only approved network traffic from known sources can communicate with DTE's applications and digital assets. Remote Access Appliances: These appliances provide the ability for DTE employees and vendors to securely connect to DTE systems and applications. Internal Certificate Management System: This system is used to issue digital certificates required for secure network communication as well as authentication for servers and endpoint devices. Secure File Transfer: This system is dedicated to enable DTE to securely exchange data with external entities to support business processes. Following is the scope of 2029: Web Proxy Appliances: Provides protection for DTE users and servers communicating to the external websites. It prevents endpoint devices and servers from being exploited by risky websites. Network Firewalls: Protects the DTE network from external as well as internal threats. Ensures only approved network traffic from known sources can communicate with DTE's applications and digital assets. External Domain Name System: These appliances provide the capability of connecting Uniform Resource Locator (URL) address of a web page/ requests for DTE applications into specific network addresses so these applications could be accessed from the internet. Virtual Private Network (VPN) Software: This software enables the DTE laptops to securely connect to DTE's network, which is	Improved employee and customer experience - Security firmware being kept up to date reduces outages related to vulnerabilities and operational issues. Protection of customer, employee and corporate data: Avoid exploitation of vulnerabilities by patching the security infrastructure.	A 'do-nothing' alternative is not acceptable as unmitigated cyber risks could lead to serious cyber incidents with financial and data loss implications.	Not Applicable	Environment is not cloud based.	Yes	1/2/2028	12/31/2029	$ 1,421,334.64	$ 1,416,784.84	$ 210,521.88		$ 986,676.96		$ 219,588.00	$ 4,320.00	$ 4,320.00					$ 3,127.88
129	2025	Virtual Desktop Infrastructure Asset Health	Return to Health	Shared	Infrastructure Operations	Steve Ambrose	OHMD0002387	Actual	The recommended solution is to procure and replace the following hardware in 2024: 1) pci-v8 c430 Virtual Desktop Infrastructure Server 2) pci-app c415 Application Server 3) pci-v8 c430ze Virtual Desktop Infrastructure Server 4) Netscalers, which provide load balancing, will be replaced with current supported versions (appconnect, c3800connect, cscvonect, pcicvonect, mscvonect) Additionally, the following hardware would be procured and replaced in 2025: 1) Netscalers, which provide load balancing, will be replaced with current supported versions (appconnect, c3800connect, cscvonect, pcicvonect, mscvonect) 2) MCHPT Cluster will be replaced to current supported version 3) pci-v8 c435 - Virtual Desktop Infrastructure Server 4) pci-app c435 - Application Server 5) Storage Switches will be replaced with current supported devices Virtual desktops are used by both Gas and Electric staff hence it is a shared asset.	Customer Experience: VDI Infrastructure is utilized by both internal (helpdesk team, applications) and external customers for secure virtual network connectivity. Implementation of this effort provides significant impact in terms of performance and efficiency of DTE's virtual assets. Operational reliability: Replacement of end-of-life hardware ensures operational management and productivity maintenance. Employee Engagement: This effort provides the necessary virtual connectivity to DTE's existing as well as new employees increasing productivity.	1) Do Nothing: This option is not possible as it will result virtual connectivity loss for around 7,000 users across the enterprise. 2) Azure was considered as an alternative solution however it was determined that the performance and efficiency of virtual desktops would not be optimal and the costs of procurement was significantly higher.	Not Applicable	No cloud infrastructure is utilized however a need for the use of public cloud is being evaluated.	Yes	1/2/2024	12/31/2025	$ 1,464,257.00	$ 1,464,256.67	$ 114,988.00	$ 15,651.00	$ 979,146.00	$ 244,971.79	$ 110,517.00	$ -	$ -			$ -
130	2026	Virtual Desktop Infrastructure Asset Health	Return to Health	Shared	Infrastructure Operations	Steve Ambrose	OHMD0002485	Level 3	The following hardware would be procured/replaced in 2026: VDI = Virtual Desktop Infrastructure PACs = Physical Access Controls, a NERC app currently hosted on Citrix that needs to be moved to Azure Virtual Desktops 1) pci-v8 c430e cluster - Hosts general DTE Desktop (275 VDI) available to all DTE employees/contractors 2) pci-v8 c435 cluster - Hosts 325 dedicated VDI 3) pci-pci c431 cluster - Hosts 200 external customer service reps and 100 internal PCI users 4) NERC installation - 8 virtual servers hosting 60 users for NERC PACs system	Customer Experience: VDI Infrastructure is utilized by both internal (helpdesk team, applications) and external customers for secure virtual network connectivity. Implementation of this effort provides significant impact in terms of performance and efficiency of DTE's virtual assets. Operational reliability: Replacement of end-of-life hardware ensures operational management and productivity maintenance. Employee Engagement: This effort provides the necessary virtual connectivity to DTE's existing as well as new employees increasing productivity.	1) Do Nothing: This option is not possible as it will result virtual connectivity loss for around 7,000 users across the enterprise. 2) Citrix was considered as the incumbent solution, but it didn't align with our corporate direction and the company has experienced turbulent changes as a result of an ownership change. 3) VMWare was considered but it was, best case, a "like for like" replacement for our existing solution that didn't align with our corporate direction and the company has experienced turbulent changes as a result of an ownership change.	Core energy management or cyber osecurity system - stay on premise	Forsee a mix of private and public cloud based on computing needs	Yes	1/2/2026	12/31/2026	$ 931,888.88	$ 851,860.00	$ 535,226.00		$ 608,060.00		$ 118,625.00	$ 80,028.00	$ 80,028.00					$ 57,940.27
131	2027	Virtual Desktop Infrastructure Asset Health	Return to Health	Shared	Infrastructure Operations	Steve Ambrose	OHMD0004340	Level 3	There will be sustainment funding needed for these recommended solutions. VDI = Virtual Desktop Infrastructure PACs = Physical Access Controls, a NERC app currently hosted on Citrix that needs to be moved to Azure Virtual Desktops 1) pci-v8 c430e cluster - hosts general DTE Desktop (275 VDI) available to all DTE employees/contractors 2) pci-v8 c435 cluster - Hosts 325 dedicated VDI 3) pci-pci c431 cluster - Hosts 200 external customer service reps and 100 internal PCI users 4) NERC installation - 8 virtual servers hosting 60 users for NERC PACs system	Customer Experience: VDI Infrastructure is utilized by both internal (helpdesk team, applications) and external customers for secure virtual network connectivity. Implementation of this effort provides significant impact in terms of performance and efficiency of DTE's virtual assets. Operational reliability: Replacement of end-of-life hardware ensures operational management and productivity maintenance. Employee Engagement: This effort provides the necessary virtual connectivity to DTE's existing as well as new employees increasing productivity.	1) Do Nothing: This option is not possible as it will result virtual connectivity loss for around 7,000 users across the enterprise. 2) Citrix was considered as the incumbent solution, but it didn't align with our corporate direction and the company has experienced turbulent changes as a result of an ownership change. 3) VMWare was considered but it was, best case, a "like for like" replacement for our existing solution that didn't align with our corporate direction and the company has experienced turbulent changes as a result of an ownership change.	Core energy management or cyber osecurity system - stay on premise	Forsee a mix of private and public cloud based on computing needs	No	1/2/2027	12/31/2027	$ 908,419.64	$ 858,402.14	$ 500,032.50				$ 358,389.64	$ 50,017.50	$ 50,017.50					$ 36,212.67
132	2028	Virtual Desktop Infrastructure Asset Health	Return to Health	Shared	Infrastructure Operations	Steve Ambrose	OHMD0004341	Level 3	There will be sustainment funding needed for these recommended solutions. VDI = Virtual Desktop Infrastructure PACs = Physical Access Controls, a NERC app currently hosted on Citrix that needs to be moved to Azure Virtual Desktops 1) pci-v8 c430e cluster - hosts general DTE Desktop (275 VDI) available to all DTE employees/contractors 2) pci-v8 c435 cluster - Hosts 325 dedicated VDI 3) pci-pci c431 cluster - Hosts 200 external customer service reps and 100 internal PCI users 4) NERC installation - 8 virtual servers hosting 60 users for NERC PACs system	Customer Experience: VDI Infrastructure is utilized by both internal (helpdesk team, applications) and external customers for secure virtual network connectivity. Implementation of this effort provides significant impact in terms of performance and efficiency of DTE's virtual assets. Operational reliability: Replacement of end-of-life hardware ensures operational management and productivity maintenance. Employee Engagement: This effort provides the necessary virtual connectivity to DTE's existing as well as new employees increasing productivity.	1) Do Nothing: This option is not possible as it will result virtual connectivity loss for around 7,000 users across the enterprise. 2) Citrix was considered as the incumbent solution, but it didn't align with our corporate direction and the company has experienced turbulent changes as a result of an ownership change. 3) VMWare was considered but it was, best case, a "like for like" replacement for our existing solution that didn't align with our corporate direction and the company has experienced turbulent changes as a result of an ownership change.	Core energy management or cyber osecurity system - stay on premise	Forsee a mix of private and public cloud based on computing needs	No	1/2/2028	12/31/2028	$ 914,812.00	$ 864,794.50	$ 500,032.50				$ 364,782.00	$ 50,017.50	$ 50,017.50					$ 36,212.67
133	2025	Wide Area Network and Wireless Local Area Network Expansion	Return to Health	Shared	Infrastructure Operations	Steve Ambrose	OHMD0001732	Actual	Approved in U-21460																			
134	2026	Wide Area Network and Wireless Local Area Network Expansion	Return to Health	Shared	Infrastructure Operations	Steve Ambrose	OHMD0001462	Level 3	Approved in U-21460																			
135	2027	Wide Area Network and Wireless Local Area Network Expansion	Return to Health	Shared	Infrastructure Operations	Steve Ambrose	OHMD0001462	Level 3	This is a year-over-year demand and continuation of Demand 1732, where DTE needs to maintain its network asset health (hardware, software, designs and architecture), performing its wireless local area network and wide area network infrastructure/services. In addition, DTE also has to meet the ever changing business requirements by ensuring the appropriate levels of network services including equipment, capacity etc. Equipment includes routers, switches, circuits, call managers, wireless LAN controllers, session border controllers etc. that are needed to meet the WAN and WLAN requirements. In addition, this ski includes appropriate levels of software licensing. WAN Scope: This effort aims to provides appropriate WAN communications including both data and VOIP needs for daily business operations, ensuring security and sustainability. Constant focus and investment are needed to keep the WAN infrastructure/services up to date and meet the business needs. Example: 1) Fiber/Ethernet circuits are being upgraded assessing various multiple DTE sites to meet the current and/or changing needs on higher bandwidth, improved WAN IP based capabilities including SIP. This effort provides robust, redundant, secure, sustainable and scalable solutions to fulfill business telecommunication needs. WLAN Scope: This effort aims to provides appropriate wireless LAN communication needs of daily business operations, ensuring security and sustainability. Providing Network connectivity at the point of activity. Example: 1) Field crew in DTE truck/service vehicles with MDSs requiring external wireless connectivity in DTE premises including yards, garages and parking lots. 2) A plant operator needing to perform a safe worker observation of the point of activity. In addition, this project will help improve wireless coverage for more densely populated within DTE campuses.	WLAN: Provides toll, reliable, safe and dependable network connection at the point of activity enabling efficiency and speed of operations. WAN: Upgrading the telecommunications platform across the enterprise (excluding Customer Service service which resides on a different system) will allow for a more efficient use of the network and accessibility. Wide Area Network technologies enables the supporting of Call Center locations and Service Center locations who have direct communication with the customer. The solution will aid CR, Dispatch and Service Center support employees to better support Customers. Improved Wide Area Network capabilities including, network connectivity speed, backhaul, bandwidth, redundancy, latency and reliability that will improve employee experience. Provide connectivity to all employees to any DTE locations with their choice of devices (Future of Where We Work). Savings from the reduction in WAN incident tickets. Reduction of leases for external solutions footprint WAN: Project Aligns to Safety (High Impact), Growth Opportunity (Medium Impact), Employee Engagement (High Impact). Operational Excellence (High Impact). Savings from the reduction in WAN incident tickets and lease costs. Wide Area Network related disconnects and performance issues will significantly reduce, in addition providing reliable connection in any point of activity within the DTE locations. Reduction of Unplanned Outages (Target: 20% reduction) Deploying Next Generation infrastructure to support wide area connectivity for enabling high speed backhaul to support new and updated business applications and mobile technologies at DTE. Examples: Support for Teams/SIP based voice infrastructure.	Not Applicable	WLAN Wireless solution is the alternative to hard wired networks, this is to cater to the new mobile applications which DTE is looking to implement. WAN: Business capabilities based on network and telecommunications will be adversely impacted. e.g. if DTE doesn't adopt a SIP solution it could impact the Contact Center. If proper WAN redundancy is not developed the SOC business unit may not be able to communicate with the appropriate remote terminal units used in the field. The do nothing alternative would not allow us to meet the requirements of the business, reduce connectivity availability, and delay the collaboration capabilities in service to the business of DTE and was rejected.	Not Applicable	e, no cloud computing is required WLAN: This case will replace the end of life wireless infrastructure to support	Yes	1/2/2026	12/31/2027	$ 1,318,253.98	$ 999,471.62	$ 311,896.86		$ 424,999.96		$ 262,606.00	$ 18,791.08	$ 16,381.08	$ 2,400.00				$ 13,597.50
136	2028	Wide Area Network and Wireless Local Area Network Expansion	Return to Health	Shared	Infrastructure Operations	Steve Ambrose	OHMD0004115	Level 3	This is a year-over-year demand and continuation of Demand 1732, where DTE needs to maintain its network asset health (hardware, software, designs and architecture), performing its wireless local area network and wide area network infrastructure/services. In addition, DTE also has to meet the ever changing business requirements by ensuring the appropriate levels of network services including equipment, capacity etc. Equipment includes routers, switches, circuits, call managers, wireless LAN controllers, session border controllers etc. that are needed to meet the WAN and WLAN requirements. In addition, this ski includes appropriate levels of software licensing. WAN Scope: This effort aims to provides appropriate WAN communications including both data and VOIP needs for daily business operations, ensuring security and sustainability. Constant focus and investment are needed to keep the WAN infrastructure/services up to date and meet the business needs. Example: 1) Fiber/Ethernet circuits are being upgraded to platform robust and compliant with the data and VoIP needs including PRI Trunks, etc). This project will continuously keep assessing various multiple DTE sites to meet the current and/or changing needs on higher bandwidth, improved WAN IP based capabilities including SIP. This effort provides robust, redundant, secure, sustainable and scalable solutions to fulfill business telecommunication needs. WLAN Scope: This effort aims to provides appropriate wireless LAN communication needs of daily business operations, ensuring security and sustainability. Providing Network connectivity at the point of activity. Example: 1) Field crew in DTE truck/service vehicles with MDSs requiring external wireless connectivity in DTE premises including yards, garages and parking lots. 2) A plant operator needing to perform a safe worker observation of the point of activity. In addition, this project will help improve wireless coverage for more densely populated within DTE campuses.	WLAN: Provides toll, reliable, safe and dependable network connection at the point of activity enabling efficiency and speed of operations. WAN: Upgrading the telecommunications platform across the enterprise (excluding Customer Service service which resides on a different system) will allow for a more efficient use of the network and accessibility. Wide Area Network technologies enables the supporting of Call Center locations and Service Center locations who have direct communication with the customer. The solution will aid CR, Dispatch and Service Center support employees to better support Customers. Improved Wide Area Network capabilities including, network connectivity speed, backhaul, bandwidth, redundancy, latency and reliability that will improve employee experience. Provide connectivity to all employees to any DTE locations with their choice of devices (Future of Where We Work). Savings from the reduction in WAN incident tickets. Reduction of leases for external solutions footprint WAN: Project Aligns to Safety (High Impact), Growth Opportunity (Medium Impact), Employee Engagement (High Impact). Operational Excellence (High Impact). Savings from the reduction in WAN incident tickets and lease costs. Wide Area Network related disconnects and performance issues will significantly reduce, in addition providing reliable connection in any point of activity within the DTE locations. Reduction of Unplanned Outages (Target: 20% reduction) Deploying Next Generation infrastructure to support wide area connectivity for enabling high speed backhaul to support new and updated business applications and mobile technologies at DTE. Examples: Support for Teams/SIP based voice infrastructure.	Not Applicable	WLAN Wireless solution is the alternative to hard wired networks, this is to cater to the new mobile applications which DTE is looking to implement. WAN: Business capabilities based on network and telecommunications will be adversely impacted. e.g. if DTE doesn't adopt a SIP solution it could impact the Contact Center. If proper WAN redundancy is not developed the SOC business unit may not be able to communicate with the appropriate remote terminal units used in the field. The do nothing alternative would not allow us to meet the requirements of the business, reduce connectivity availability, and delay the collaboration capabilities in service to the business of DTE and was rejected.	Not Applicable	e, no cloud computing is required WLAN: This case will replace the end of life wireless infrastructure to support	Yes	1/2/2028	12/31/2029	$ 1,316,344.29	$ 998,711.26	$ 310,056.25		$ 425,000.04		$ 263,655.30	$ 19,632.00	$ 19,632.00					$ 14,214.29
137	2025	Network Segmentation phase 2+ emergent extension	IT Enhancements	Shared	Infrastructure Operations	Steve Ambrose	OHMD0001362	Actual	Approved in U-21460																			
138	2025	Beam Cloud	Strategic	Shared	Infrastructure Operations	Steve Ambrose	OHMD0001017	Actual	Approved in U-21460																			
139	2026	Digital Platform Application Health	Sustainment	Electric	Enterprise Data & Digital Platform	Steve Ambrose	OHMD0004114	Level 3	To address the need for maintaining the critical application needs and assess and nature the functionality of the platform and supported capabilities, the proposed solution is to enable the ongoing support and proactive management of this critical platform. This includes engaging in activities such as security updates and patches, cloud configuration, maintaining pipelines, mitigating and resolving errors code issues that impact the business functions. This also includes building and maintaining the platform's ability to manage vendor crew rostering, event management, and timesheet management ensuring continuity product, such as user management, vendor management, equipment management, communication services, and inbound and outbound integration gateways with other business critical applications (such as CMS, Maximo, AAD, Data Platforms, etc.)	Supports DTE's strategic goal of restoring customer power within 48 hours by ensuring the Digital Platform remains stable, secure, and responsive during critical events. Enables the platform to consistently meet Service Level Agreements (SLAs) required by business stakeholders, reducing operational risk and improving performance.	The alternative to this investment is to do nothing; however, this is not a viable option. Regular system maintenance, patching, and updates to cloud infrastructure are essential to ensure the continued support of critical business processes. Regular maintenance will ensure the Digital Platform remains operable, secure, and functioning as intended. Another alternative that was considered was an industry standard platform, Arcos, and the company decided not to pursue this alternative at this time.	Standard market-based and/or commoditized non-core energy workload - deploy in commercial cloud	The platform is aligned with DTE's cloud computing strategy, leveraging Azure public cloud.	No	1/5/2026	12/31/2026	$ 1,296,592.29	$ 1,296,592.29	$ 777,594.29	$ 24,000.00			$ 497,608.00	$ -						$ -
140	2027	Digital Platform Application Health	Sustainment	Shared	Enterprise Data & Digital Platform	Steve Ambrose	OHMD0004173	Level 3	To maintain the Enterprise Data Platform, this includes build and/or update necessary environment to support new data trends like AI, ML, automation frameworks, Design, Develop and Deploy business solutions to support data initiatives. Adopt Cloud Native Architecture Cloud platforms provide scalability, flexibility, and cost-efficiency compared to on-premises solutions. Leverage Serverless Computing to boost efficiency, reduce infrastructure overheads, reducing operational overhead and improve it's Data Lakehouse Architecture. To address the need for maintaining the short-term needs and assess and nature the functionality of the Digital Platform and the other supported applications, the proposed solution is to enable the ongoing support and proactive management of the platform. This includes engaging in activities such as security updates and patches, cloud configuration, maintaining pipelines, mitigating and resolving errors code issues that impact the business functions. These activities will directly support the platform's ability to manage vendor crew rostering, event management, and timesheet management ensuring continuity and reliability.	Supports DTE's strategic goal of restoring customer power within 48 hours by ensuring the Digital Platform remains stable, secure, and responsive during critical events. Enables the platform to consistently meet Service Level Agreements (SLAs) required by business stakeholders, reducing operational risk and improving performance.	The alternative to this investment is to do nothing; however, this is not a viable option. Regular system maintenance, patching, and updates to cloud infrastructure are essential to ensure the continued support of critical business processes. Regular maintenance will ensure both the Enterprise Data and Digital Platforms remains operable, secure, and functioning as intended. Following alternatives were considered: Arcos - Industry standard platform which the Company decided not to pursue this alternative at this time. Cloud vs. On-Premise Solutions for cross-platform reporting Data Warehousing Alternatives: Databricks Delta Lake vs SQL DB Data Lake vs. Data Lakehouse Data Governance and Security Alternatives: Infogix vs Azure Purview	Standard market-based and/or commoditized non-core energy workload - deploy in commercial cloud	The platform is aligned with DTE's cloud computing strategy, leveraging Azure public cloud.	No	1/4/2027	12/31/2027	$ 4,380,101.38	$ 2,890,100.78	$ 1,690,796.78	$ 36,000.00			$ 1,068,334.00	$ 1,580,054.00	$ 1,580,054.00					$ 1,143,890.03
141	2028	Digital Platform Application Health	Sustainment	Shared	Enterprise Data & Digital Platform	Steve Ambrose	OHMD0004240	Level 3	To maintain and evolve the Enterprise Data Platform, the team will build and update the necessary environments to support emerging data trends such as AI, machine learning, automation frameworks, and cloud native architectures. This includes designing, developing, and deploying business solutions that enable data-driven initiatives. The approach incorporates adopting cloud native patterns for improved scalability, flexibility, and cost-efficiency, leveraging serverless computing for event-driven workloads to reduce operational overhead, and implementing a modern Data Lakehouse architecture. To address the need for maintaining the short-term needs and assess and mature the functionality of the Digital Platform and the other supported applications, the proposed solution is to enable the ongoing support and proactive management of the platform. This includes engaging in activities such as security updates and patches, cloud configuration, maintaining pipelines, and mitigating or resolving code-related issues that impact business functions. These efforts directly ensure the platform's reliability and continuity, particularly for vendor crew rostering, event management, and timesheet management.	Supports DTE's strategic goal of restoring customer power within 48 hours by ensuring the Digital Platform remains stable, secure, and responsive during critical events. Enables the platform to consistently meet Service Level Agreements (SLAs) required by business stakeholders, reducing operational risk and improving performance.	The alternative to this investment is to do nothing; however, this is not a viable option. Regular system maintenance, patching, and updates to cloud infrastructure are essential to ensure the continued support of critical business processes. Regular maintenance will ensure both the Enterprise Data and Digital Platforms remains operable, secure, and functioning as intended. Following alternatives were considered: Arcos - Industry standard platform which the Company decided not to pursue this alternative at this time. Cloud vs. On-Premise Solutions for cross-platform reporting Data Warehousing Alternatives: Databricks Delta Lake vs SQL DB Data Lake vs. Data Lakehouse Data Governance and Security Alternatives: Infogix vs Azure Purview	Standard market-based and/or commoditized non-core energy workload - deploy in commercial cloud	ud computing technology strategy to leverage the full power of cloud services to innovate, optimize costs, impro	No	1/3/2028	12/29/2028	$ 4,460,995.38	$ 2,890,024.28	$ 1,686,255.28	$ 40,000.00			$ 1,075,771.00	$ 1,660,041.10	$ 1,660,041.10					$ 1,201,869.76
142	2026	Enterprise Data Analytics - Alteryx and Qlik License Renewal	Sustainment	Shared	Enterprise Data & Digital Platform	Steve Ambrose	OHMD0003695	Level 3	Approved in U-21460																			
143	2026	Enterprise Data Platform Application Health	Sustainment	Shared	Enterprise Data & Digital Platform	Steve Ambrose	OHMD0001298	Actual	Approved in U-21460																			
144	2026	Enterprise Data Platform Application Health	Sustainment	Shared	Enterprise Data & Digital Platform	Steve Ambrose	OHMD0003407	Actual	Approved in U-21460																			
145	2025	Cure Enterprise Resource Planning Blocks and Packs	Regulatory/Compliance	Shared	Enterprise Application	Steve Ambrose	OHMD0001215	Actual	Approved in U-21460																			
146	2026	Core Enterprise Resource Planning Blocks and Packs	Regulatory/Compliance	Shared	Enterprise Application	Steve Ambrose	OHMD0001398	Level 3	Approved in U-21460																			

147	2027	Core Enterprise Resource Planning Stacks and Packs	Regulatory/Compliance	Shared	Corporate Application	Steve Ambrose	DPHD0002386	Level 3	For FY26 - FY28: There should be recurring annual investment to ensure the Core Enterprise Resource Planning platform is up to date with the latest required software support packs (major version upgrades) and patches (minor changes). This includes yearly application patching of ECC HR - service packs for required year end payroll and benefits processing to ensure business processes will continue to run successfully and in compliance with updated tax laws. This is a mandatory investment for legal and regulatory purposes. The system has to be upgraded with the latest Human Resources updates from vendor SAP in order to run year-end payroll, produce W-2's, and comply with mandatory State, local, and Federal reporting. In addition, we are migrating to the SAP S/4 Hana platform by 2027 and preparation for that move will begin in 2026, with conversion to UNICODE. Scope by Year 2027 There should be recurring annual investment to ensure the Core Enterprise Resource Planning platform is up to date with the latest required software support packs (major version upgrades) and patches (minor changes). This includes yearly application patching of ECC HR - service packs for required year end payroll and benefits processing to ensure business processes will continue to run successfully and in compliance with updated tax laws. This is a mandatory investment for legal and regulatory purposes. The system has to be upgraded with the latest Human Resources updates from vendor SAP in order to run year-end payroll, produce W-2's, and comply with mandatory State, local, and Federal reporting. In addition, we are migrating to the SAP S/4 Hana platform by 2027 and preparation for that move will begin in 2026, with conversion to UNICODE. The scope for 2027 will include processing required to migrate to the S/4 Hana platform in addition to the usual yearly upgrades.	Core ERP Stacks and Packs is a mandatory, annual investment required to meet regulatory obligations, ensure payroll and financial accuracy, reduce operational risk, and preserve the integrity of the enterprise ERP platform. The work directly enables compliant business operations and is essential to continued system stability.	Applications will not be able to process legally mandated payroll, W-2, vacation quota updates if we do nothing. Application will fall out of maintenance, lose compatibility with other DTE infrastructure. We do not have a choice to do nothing.	Does not follow cloud computing strategy - exception	cloud computing strategy. Portions of EBS (Successf actors, myDTE) are cloud-based. Remaining portions of EBS	No	1/2/2026	12/31/2028	$ 1,302,769.19	$ 1,871,764.77	$ 454,111.73	$ 763,700.00		$ 453,143.34	$ 231,414.42	$ 108,814.42	$ 124,800.00				$ 197,544.04
148	2028	Core Enterprise Resource Planning Stacks and Packs	Regulatory/Compliance	Shared	Corporate Application	Steve Ambrose	DPHD0002386	Level 3	For FY26 - FY28: There should be recurring annual investment to ensure the Core Enterprise Resource Planning platform is up to date with the latest required software support packs (major version upgrades) and patches (minor changes). This includes yearly application patching of ECC HR - service packs for required year end payroll and benefits processing to ensure business processes will continue to run successfully and in compliance with updated tax laws. This is a mandatory investment for legal and regulatory purposes. The system has to be upgraded with the latest Human Resources updates from vendor SAP in order to run year-end payroll, produce W-2's, and comply with mandatory State, local, and Federal reporting. In addition, we are migrating to the SAP S/4 Hana platform by 2027 and preparation for that move will begin in 2026, with conversion to UNICODE. The scope for 2028 will include updates exclusive to the S/4 Hana platform in addition to the usual yearly upgrades. Scope by Year 2028 There should be recurring annual investment to ensure the Core Enterprise Resource Planning platform is up to date with the latest required software support packs (major version upgrades) and patches (minor changes). This includes yearly application patching of ECC HR - service packs for required year end payroll and benefits processing to ensure business processes will continue to run successfully and in compliance with updated tax laws. This is a mandatory investment for legal and regulatory purposes. The system has to be upgraded with the latest Human Resources updates from vendor SAP in order to run year-end payroll, produce W-2's, and comply with mandatory State, local, and Federal reporting. In addition, we are migrating to the SAP S/4 Hana platform by 2027 and preparation for that move will begin in 2026, with conversion to UNICODE. The scope for 2028 will include updates exclusive to the S/4 Hana platform in addition to the usual yearly upgrades.	Core ERP Stacks and Packs is a mandatory, annual investment required to meet regulatory obligations, ensure payroll and financial accuracy, reduce operational risk, and preserve the integrity of the enterprise ERP platform. The work directly enables compliant business operations and is essential to continued system stability.	Applications will not be able to process legally mandated payroll, W-2, vacation quota updates if we do nothing. Application will fall out of maintenance, lose compatibility with other DTE infrastructure. We do not have a choice to do nothing.	Does not follow cloud computing strategy - exception	cloud computing strategy. Portions of EBS (Successf actors, myDTE) are cloud-based. Remaining portions of EBS	No	1/2/2026	12/31/2028	$ 1,898,257.88	$ 1,883,102.24	$ 451,439.37	$ 798,500.00		$ 453,142.87	$ 227,155.75	$ 104,155.75	$ 123,000.00				$ 394,483.76
149	2025	Secure 2.0 Act for 401K	Regulatory/Compliance	Shared	Corporate Application	Steve Ambrose	DPHD0002805	Actual	SAP Benefit module will be updated to incorporate the Secure 2.0 requirements and streamlining 401k rollover elections.	Under current law, catch-up contributions to a qualified retirement plan can be made on a pre-tax or Roth basis (if permitted by the plan sponsor). Section 603 of the Act provides all catch-up contributions to qualified retirement plans are subject to Roth tax treatment, effective for taxable years after December 31, 2023. An exception is provided for employees with compensation of $145,000 or less. In addition, a design change of the 401k Catch-up election was completed to have one election vs. multi-elections for 401k tax rollovers.	There is no alternate for Secure 2.0 Act, but the design change of the 401k Catch-up election option and Pre and Post tax updates continue to be manual.	Not Applicable	Cloud Computing is not applicable as this project is SAP on premise.	Yes	1/7/2025	12/31/2025	$ 504,765.68	$ 402,254.88	$ 32,405.94	$ 320,930.38	$ 10,242.46		$ 38,808.54	$ 102,548.07	$ 24,971.62	$ 77,576.25	$ 0.25			$ 76,491.90
150	2025	Corporate Services Application Health	Sustainment	Shared	Corporate Application	Steve Ambrose	DPHD0002216	Actual																						
151	2026	Corporate Services Application Health	Sustainment	Shared	Corporate Application	Steve Ambrose	DPHD0002421	Level 3																						
152	2027	Corporate Services Application Health	Sustainment	Shared	Corporate Application	Steve Ambrose	DPHD0002421	Level 3	The Corporate Services Application Health budget is critical as it provides continued support of the over 42 applications in Corporate Communications, Corporate Safety, Corporate & Government Affairs, Fleet Optimization, Public Affairs, Supply Chain, Environmental Management & Safety, Corporate Strategy. 2027 Migrate Facilities tickets from Maximo to Ejeta Enhance the CityDTE home page and search functionalities Prioritize and implement new functionality and features as requested by our Corporate Services business partners for the following applications: SISTEMA 2.0 (SMO), CityDTE, Workspace Reservation System (Engage), ON TRACK, RICOH Intelligent Mail Delivery Services, PORTFOLIO (EXTENSIO), SAFETY WORKER OBSERVATION, SUPPLY CHAIN BUSINESS WAREHOUSE, CARE FORCE, Resource Advisor, Life Critical Phone Application, DYNEGRIND COLLECTIONS & MONITORING PLANT SYSTEM, Quantum, DTE CARES, DTE Force - Fuel Service Net, ReadersAssistant, AirApp - E-Boards, eCampus Workspace Planning (Services), FleetQRS, United Way - Stratus Line, Ariosoto, ENVIRONMENTAL MANAGEMENT INFORMATION SYSTEM, Honeywell EBI, Unitise, VFA Capital Planning, DTE FREIGHT, CLIC, TREOLIN NIAGARA, PM - Power Improvements Map, ENVIRONMENTAL MANAGEMENT INFO. SYSTEM Upgrade/Patch The funding will also support critical updates and enhancements, including software, hardware, and database environment patches. This includes required version upgrades driven by regulatory changes, resolution of security vulnerabilities, and proactive protection against system failure and potential cyber threats.	Employees provide value to their organizations and our customers through the use of technology. Maintaining a stable and updated computing environment allows the employees to complete daily tasks efficiently and with less errors. Applying application upgrades and enhancements for existing products allows the business units to access new business functionality and in some cases assists DTE in meeting regulatory compliance objectives.	Maintaining the health of DTE computing assets is necessary to protect DTE against security threats, address product bug fixes and provide support for hardware failures. Non-compliance with software updates, replace or retirement also takes into consideration vendor product roadmaps and business efficacy improvement. The need to replace or update all applications that are within the portfolio is continuously evaluated throughout the year. The identification of applications subject to an application health update, replace or retirement also takes into consideration vendor product roadmaps and business efficacy improvement. Not keeping critical business processes to security breaches. Allowing applications and operating environments to become obsolete puts DTE customers at risk of data security breaches.	Not Applicable	a availability of cloud technology is considered when evaluating applications for updates or replacement. A cloud	No	1/2/2026	12/31/2028	$ 984,000.36	$ 810,000.36	$ 531,902.36			$ 301,098.00	$ 153,000.00	$ 145,200.00	$ 10,800.00				$ 109,324.69
153	2028	Corporate Services Application Health	Sustainment	Shared	Corporate Application	Steve Ambrose	DPHD0002421	Level 3	The Corporate Services Application Health budget is critical as it provides continued support of the over 42 applications in Corporate Communications, Corporate Safety, Corporate & Government Affairs, Fleet Optimization, Public Affairs, Supply Chain, Environmental Management & Safety, Corporate Strategy. 2028 Move PAC to Quorum for Government Affairs Implement Copilot functionalities for Fleet Prioritize and implement new functionality and features requested by our Corporate Services business partners for the following applications: SISTEMA 2.0 (SMO), CityDTE, Workspace Reservation System (Engage), ON TRACK, RICOH Intelligent Mail Delivery Services, PORTFOLIO (EXTENSIO), SAFETY WORKER OBSERVATION, SUPPLY CHAIN BUSINESS WAREHOUSE, CARE FORCE, Resource Advisor, Life Critical Phone Application, DYNEGRIND COLLECTIONS & MONITORING PLANT SYSTEM, Quantum, DTE CARES, DTE Force - Fuel Service Net, ReadersAssistant, AirApp - E-Boards, eCampus Workspace Planning (Services), FleetQRS, United Way - Stratus Line, Ariosoto, ENVIRONMENTAL MANAGEMENT INFORMATION SYSTEM, Honeywell EBI, Unitise, VFA Capital Planning, DTE FREIGHT, CLIC, TREOLIN NIAGARA, PM - Power Improvements Map, ENVIRONMENTAL MANAGEMENT INFO. SYSTEM Upgrade/Patch The funding will also support critical updates and enhancements, including software, hardware, and database environment patches. This includes required version upgrades driven by regulatory changes, resolution of security vulnerabilities, and proactive protection against system failure and potential cyber threats.	Employees provide value to their organizations and our customers through the use of technology. Maintaining a stable and updated computing environment allows the employees to complete daily tasks efficiently and with less errors. Applying application upgrades and enhancements for existing products allows the business units to access new business functionality and in some cases assists DTE in meeting regulatory compliance objectives.	Maintaining the health of DTE computing assets is necessary to protect DTE against security threats, address product bug fixes and provide support for hardware failures. Non-compliance with software updates, replace or retirement also takes into consideration vendor product roadmaps and business efficacy improvement. The need to replace or update all applications that are within the portfolio is continuously evaluated throughout the year. The identification of applications subject to an application health update, replace or retirement also takes into consideration vendor product roadmaps and business efficacy improvement. Not keeping critical business processes to security breaches. Allowing applications and operating environments to become obsolete puts DTE customers at risk of data security breaches.	Not Applicable	a availability of cloud technology is considered when evaluating applications for updates or replacement. A cloud	No	1/2/2026	12/31/2028	$ 977,000.24	$ 829,000.24	$ 523,002.24			$ 301,098.00	$ 152,000.00	$ 141,200.00	$ 10,800.00				$ 110,048.00
154	2025	Documentum (EDM) Application Health	Sustainment	Shared	Corporate Application	Steve Ambrose	DPHD0001982	Actual																						
155	2026	Documentum (EDM) Application Health	Sustainment	Shared	Corporate Application	Steve Ambrose	DPHD0002486	Level 3	A supported interface to our work management system is needed to ensure continued user access to documents while executing work orders, as well as a complete document management workflow that will enforce storage standards to ensure business processes with digital records management. This will allow employees the ability to search for documentation and associate documents to equipment or location, to better complete asset Work Orders at point of activity. 2027 Investment to support Security patches, minor system upgrades, value added small enhancements and organic system growth (sizing). A Point & Field (P&F) Document Management Governance Board has been established to define an aligned strategy that addresses gaps in how documents are received, processed, reviewed, approved, stored, retrieved, and eventually purged. As the Board addresses gaps found, the yearly funding will support addressing those specific gaps to maintain user functionality and operational security. Monthly maintenance releases include security CIS Patching and Password changes for Compliance identified during that month. Beginning in 2027, the following work will be performed to keep the platform stable, compliant, and able to support future growth. Key reasons include: Finishing the work deferred from 2026, which is still needed to maintain smooth system performance and consistent service for the business. Keeping up with annual security and compliance requirements which continue to increase each year and require regular updates and platform improvements. Supporting ongoing growth—including more documents, more teams using the system, and more integrations tied to business processes. Maintaining reliability and avoiding operational disruptions, which become more likely if the platform is not funded at the level needed to keep it secure and supported. 2028 Investment to support Security patches, minor system upgrades, value added small enhancements and organic system growth (sizing). A Point & Field (P&F) Document Management Governance Board has been established to define an aligned strategy that addresses gaps in how documents are received, processed, reviewed, approved, stored, retrieved, and eventually purged. As the Board addresses gaps found, the yearly funding will support addressing those specific gaps to maintain user functionality and operational security. Monthly maintenance releases include security CIS Patching and Password changes for Compliance identified during that month.	There are functional enhancements and security upgrades that ensure continued operational performance, availability, and protection of information assets. The investment enables the system to reliably support both current and future document repository requirements and aligns with the enterprise document management strategy used across business units.	This solution has been in pace for last 10-20 years. It has been pretty stable but was not up to date with latest upgrades from the vendor.	Not Applicable	There is a cloud solution. We can't leverage that due to NERC BCSI requirements.	No	1/2/2026	12/31/2028	$ 1,058,573.29	$ 896,564.30	$ 211,257.30	$ 500,840.00		$ 164,407.00	$ 158,008.98	$ 58,908.98	$ 100,900.00				$ 110,701.71
156	2028	Documentum (EDM) Application Health	Sustainment	Shared	Corporate Application	Steve Ambrose	DPHD0002486	Level 3	A supported interface to our work management system is needed to ensure continued user access to documents while executing work orders, as well as a complete document management workflow that will enforce storage standards to ensure business processes with digital records management. This will allow employees the ability to search for documentation and associate documents to equipment or location, to better complete asset Work Orders at point of activity. 2028 Investment to support Security patches, minor system upgrades, value added small enhancements and organic system growth (sizing). A Point & Field (P&F) Document Management Governance Board has been established to define an aligned strategy that addresses gaps in how documents are received, processed, reviewed, approved, stored, retrieved, and eventually purged. As the Board addresses gaps found, the yearly funding will support addressing those specific gaps to maintain user functionality and operational security. Monthly maintenance releases include security CIS Patching and Password changes for Compliance identified during that month.	There are functional enhancements and security upgrades that ensure continued operational performance, availability, and protection of information assets. The investment enables the system to reliably support both current and future document repository requirements and aligns with the enterprise document management strategy used across business units.	This solution has been in pace for last 10-20 years. It has been pretty stable but was not up to date with latest upgrades from the vendor.	Not Applicable	There is a cloud solution. We can't leverage that due to NERC BCSI requirements.	No	1/2/2026	12/31/2028	$ 1,046,482.30	$ 890,018.26	$ 228,711.26	$ 497,500.00		$ 164,407.00	$ 157,844.64	$ 56,244.64	$ 99,600.00				$ 114,279.04
158	2025	Enterprise Applications Health	Sustainment	Shared	Corporate Application	Steve Ambrose	DPHD0001221	Actual																						
159	2026	Enterprise Applications Health	Sustainment	Shared	Corporate Application	Steve Ambrose	DPHD0002475	Level 3																						
160	2027	Enterprise Applications Health	Sustainment	Shared	Corporate Application	Steve Ambrose	DPHD0002475	Level 3	Maintain the ITS Enterprise Applications Portfolio (via hardware and software upgrades) which include multiple applications. This will keep the applications in support to receive up to date security patches which will improve the efficiency and effectiveness. The patching series by applications. For example the PACE applications are monthly patches. Other applications are semi-annual or annual version upgrades. We implement the patches into a test environment, perform testing to validate no negative consequences. Then deploy to production and perform post-validation functionality. Our vendors release regular patch/version upgrades to address the ever evolving information security landscape. DTE's standards are to be on a recent version/patch cycle to minimize our risk of security incidents. We follow the same processes on a year to year basis.	Maintains and enhances the ITS Enterprise Applications Portfolio through planned hardware and software upgrades across multiple enterprise applications. The investment preserves vendor supportability and enables continued access to current security patches, version enhancements, and compliance updates, improving system performance, reliability, and overall effectiveness The scope includes application specific upgrades executed as needed to keep systems secure, stable, and compliant. Work includes planning, testing and validation, and coordination with business teams, implemented through controlled deployment processes, including testing and validation, to ensure system stability, sustained operational capability, and regulatory compliance Vendors regularly release upgrades to address the evolving information security and regulatory landscape. This investment ensures applications remain on supported and secure versions in alignment with DTE standards and applicable NERC compliance requirements, reducing long-term cybersecurity and compliance risk. The investment extends the useful life of enterprise application assets while supporting ongoing NERC related controls, audit readiness, and operational resilience through a consistent, repeatable lifecycle year over year.	Continuing with the current system state will not result in business productivity gains. Doing nothing. DTE enterprise applications may fail out of support with the vendor and decrease the asset health. Failing out of support with the vendor will prevent us from receiving security patches, increasing our security risk.	Specialized workload - stay on premise	Currently, EDI, Everbridge, BOS and RightFax leverage public cloud.	No	1/2/2026	12/31/2028	$ 910,321.08	$ 810,360.60	$ 290,740.60	$ 323,100.00		$ 195,511.00	$ 99,060.43	$ 74,760.43	$ 20,200.00				$ 72,371.35
161	2028	Enterprise Applications Health	Sustainment	Shared	Corporate Application	Steve Ambrose	DPHD0002475	Level 3	Maintain the ITS Enterprise Applications Portfolio (via hardware and software upgrades) which include multiple applications. This will keep the applications in support to receive up to date security patches which will improve the efficiency and effectiveness. The patching series by applications. For example the PACE applications are monthly patches. Other applications are semi-annual or annual version upgrades. We implement the patches into a test environment, perform testing to validate no negative consequences. Then deploy to production and perform post-validation functionality. Our vendors release regular patch/version upgrades to address the ever evolving information security landscape. DTE's standards are to be on a recent version/patch cycle to minimize our risk of security incidents. We follow the same processes on a year to year basis.	Maintains and enhances the ITS Enterprise Applications Portfolio through planned hardware and software upgrades across multiple enterprise applications. The investment preserves vendor supportability and enables continued access to current security patches, version enhancements, and compliance updates, improving system performance, reliability, and overall effectiveness The scope includes application specific upgrades executed as needed to keep systems secure, stable, and compliant. Work includes planning, testing and validation, and coordination with business teams, implemented through controlled deployment processes, including testing and validation, to ensure system stability, sustained operational capability, and regulatory compliance Vendors regularly release upgrades to address the evolving information security and regulatory landscape. This investment ensures applications remain on supported and secure versions in alignment with DTE standards and applicable NERC compliance requirements, reducing long-term cybersecurity and compliance risk. The investment extends the useful life of enterprise application assets while supporting ongoing NERC related controls, audit readiness, and operational resilience through a consistent, repeatable lifecycle year over year.	Continuing with the current system state will not result in business productivity gains. Doing nothing. DTE enterprise applications may fail out of support with the vendor and decrease the asset health. Failing out of support with the vendor will prevent us from receiving security patches, increasing our security risk.	Specialized workload - stay on premise	Currently, EDI, Everbridge, BOS and RightFax leverage public cloud.	No	1/2/2026	12/31/2028	$ 907,792.64	$ 809,398.68	$ 293,796.68	$ 320,000.00		$ 195,511.00	$ 98,475.68	$ 73,875.68	$ 24,600.00				$ 71,296.34
162	2025	Enterprise Resource Planning	Sustainment	Shared	Corporate Application	Steve Ambrose	DPHD0001121/DPHD0001214	Actual																						
163	2026	Enterprise Resource Planning	Sustainment	Shared	Corporate Application	Steve Ambrose	DPHD0002476	Level 3																						
164	2027	Enterprise Resource Planning	Sustainment	Shared	Corporate Application	Steve Ambrose	DPHD0002476	Level 3	The Solution is to continue investing in in-place assets that support the ERP systems to maintain proper levels of software support, implement security patches, deploy environment upgrades, and adopt software releases which avoid software obsolescence. Requests for Enhancements are part of a BRM prioritization process, which is then relayed to the CORE ERP staff, and they are then scheduled for implementation using criteria of staffing availability, need for specific timing of implementation, coordination with other BU needs, and impact on improvement in turnaround, efficiencies, and asset lifecycle. We have a regular schedule of Software Monthly Maintenance Releases (11 per year, not in November due to EBS Year End HR Application patching Releases) to address application health required updates, as well as specifically scheduled software updates to address a specific issue/need as defined by the BRMs. In addition, twice weekly there are BRM initiated defect/ master data software updates that are supported by this solution funding. Many of these enhancements are driven by the Business Lines who must use their processes to meet mandatory Legal and reporting Requirements, and Human Resource agreements (payroll, Union, tax, for example). Scope by Year: 2027 The Solution is to continue investing in in-place assets that support the ERP systems to maintain proper levels of software support, implement security patches, deploy environment upgrades, and adopt software releases which avoid software obsolescence. Requests for Enhancements are part of a BRM prioritization process, which is then relayed to the CORE ERP staff, and they are then scheduled for implementation using criteria of staffing availability, need for specific timing of implementation, coordination with other BU needs, and impact on improvement in turnaround, efficiencies, and asset lifecycle. We have a regular schedule of Software Monthly Maintenance Releases (11 per year, not in November due to EBS Year End HR Application patching Releases) to address application health required updates, as well as specifically scheduled software updates to address a specific issue/need as defined by the BRMs. In addition, twice weekly there are BRM initiated defect/ master data software updates that are supported by this solution funding. Many of these enhancements are driven by the Business Line who must use their processes to meet mandatory Legal and reporting Requirements, and Human Resource agreements (payroll, Union, tax, for example). Scope by Year: 2028 The Solution is to continue investing in in-place assets that support the ERP systems to maintain proper levels of software support, implement security patches, deploy environment upgrades, and adopt software releases which avoid software obsolescence. Requests for Enhancements are part of a BRM prioritization process, which is then relayed to the CORE ERP staff, and they are then scheduled for implementation using criteria of staffing availability, need for specific timing of implementation, coordination with other BU needs, and impact on improvement in turnaround, efficiencies, and asset lifecycle. We have a regular schedule of Software Monthly Maintenance Releases (11 per year, not in November due to EBS Year End HR Application patching Releases) to address application health required updates, as well as specifically scheduled software updates to address a specific issue/need as defined by the BRMs. In addition, twice weekly there are BRM initiated defect/ master data software updates that are supported by this solution funding.	Annual capital investment in existing ERP and supporting application assets preserves and extends the useful life of these long lived enterprise systems by preventing software obsolescence and maintaining vendor supportability. Regular adoption of software releases, security patches, and environment upgrades avoids deferred technical debt that would otherwise require larger future capital outlays or accelerated system replacement. This recurring investment enables the enterprise to maintain stable, secure, and compliant ERP platforms that support critical financial, regulatory, human resources, and operational processes. By aligning enhancements through a Business Relationship Management (BRM) prioritization process, capital funds are directed toward high value improvements that increase processing efficiency, reduce turnaround time, and optimize asset lifecycle performance across business units. A structured and recurring release cadence—consisting of monthly maintenance releases, scheduled upgrades, and prioritized enhancement deployments—ensures application health, regulatory readiness, and responsiveness to evolving business and legal requirements. These improvements are funded annually in these in-place assets reducing long-term cybersecurity exposure, sustains regulatory compliance, and protects the enterprise value of ERP systems by ensuring they remain modern, supported, and aligned with business needs. This approach delivers predictable capital value year-over-year by stabilizing core platforms, extending asset longevity, and avoiding unplanned capital expenditures driven by system failure or non-compliance.	Applications will stagnate and platform will not be running on the latest releases/patches which could impact security and application performance. Do Nothing is not an option. DTE must react and comply with requirements imposed by legal and governmental entities.	Does not follow cloud computing strategy - exception	cloud computing strategy. Portions of EBS (Successf actors, myDTE) are cloud-based. Remaining portions of EBS	No	1/2/2026	12/31/2028	$ 1,244,469.88	$ 1,110,549.39	$ 340,676.39	$ 538,300.00		$ 231,073.00	$ 138,420.31	$ 99,720.31	$ 38,700.00				$ 100,226.49
165	2028	Enterprise Resource Planning	Sustainment	Shared	Corporate Application	Steve Ambrose	DPHD0002476	Level 3	The Solution is to continue investing in in-place assets that support the ERP systems to maintain proper levels of software support, implement security patches, deploy environment upgrades, and adopt software releases which avoid software obsolescence. Requests for Enhancements are part of a BRM prioritization process, which is then relayed to the CORE ERP staff, and they are then scheduled for implementation using criteria of staffing availability, need for specific timing of implementation, coordination with other BU needs, and impact on improvement in turnaround, efficiencies, and asset lifecycle. We have a regular schedule of Software Monthly Maintenance Releases (11 per year, not in November due to EBS Year End HR Application patching Releases) to address application health required updates, as well as specifically scheduled software updates to address a specific issue/need as defined by the BRMs. In addition, twice weekly there are BRM initiated defect/ master data software updates that are supported by this solution funding.	Annual capital investment in existing ERP and supporting application assets preserves and extends the useful life of these long lived enterprise systems by preventing software obsolescence and maintaining vendor supportability. Regular adoption of software releases, security patches, and environment upgrades avoids deferred technical debt that would otherwise require larger future capital outlays or accelerated system replacement. This recurring investment enables the enterprise to maintain stable, secure, and compliant ERP platforms that support critical financial, regulatory, human resources, and operational processes. By aligning enhancements through a Business Relationship Management (BRM) prioritization process, capital funds are directed toward high value improvements that increase processing efficiency, reduce turnaround time, and optimize asset lifecycle performance across business units. A structured and recurring release cadence—consisting of monthly maintenance releases, scheduled upgrades, and prioritized enhancement deployments—ensures application health, regulatory readiness, and responsiveness to evolving business and legal requirements. These improvements are funded annually in these in-place assets reducing long-term cybersecurity exposure, sustains regulatory compliance, and protects the enterprise value of ERP systems by ensuring they remain modern, supported, and aligned with business needs. This approach delivers predictable capital value year-over-year by stabilizing core platforms, extending asset longevity, and avoiding unplanned capital expenditures driven by system failure or non-compliance.	Applications will stagnate and platform will not be running on the latest releases/patches which could impact security and application performance. Do Nothing is not an option. DTE must react and comply with requirements imposed by legal and governmental entities.	Does not follow cloud computing strategy - exception	cloud computing strategy. Portions of EBS (Successf actors, myDTE) are cloud-based. Remaining portions of EBS	No	1/2/2026	12/31/2028	$ 1,238,643.16	$ 1,102,403.68	$ 336,726.80	$ 554,800.00		$ 231,073.00	$ 136,239.76	$ 98,239.76	$ 38,000.00				$ 98,657.09
166	2025	Financial Applications Health	Sustainment	Shared	Corporate Application	Steve Ambrose	DPHD0001224	Actual	Recommended solutions include: Complete technical upgrades (includes hardware) on One Source Sales & Use Tax and Teamsuite. Complete SAP purchase order work via the Prodigy application can be retired (annual savings of $70k). Ensure that all future security patches are addressed on applications such as (e.g. SAP ERP, SAP BPC, SAP BW, One Source Sales & Use Tax, PowerPlan, Visual Corporate Keeper, Teamsuite, etc.). Prioritize and implement new functionality and features when requested by our Financial business partners for the following applications SAP ERP Financial modules, SAP BPC, SAP BW, One Source Sales & Use Tax, PowerPlan, Visual Corporate Keeper, Cadency, Concur, Teamsuite, etc.). Monthly meetings occur with Controllers, Quorum meetings with other business partners to identify and prioritize any enhancements. Leadership from business partners are involved. During 2023, 2024 and 2025 functionality and feature enhancements requested by the Controller's Business Unit will be required for the BPC Application, the Oracle Financial Planning Tool and PowerPlan. On average there are 3 to 6 requests per year. - Windows servers and database upgrades, as well as disk space additions are also scheduled for the Financial Applications during 2023, 2024 and 2025.	Employee Value - DTE Financial employees will continue to have the the functionality and features required to execute their processes, and will utilize financial applications that remain compliant with Sarbanes Oxley and other compliance requirements that protect DTE from accounting errors and ensure accurate financials. These enhancements further improve efficiencies in the financial close process and improve overall system health. The DTE Financial Organizations will be able to obtain minor enhancements on an annual basis to their applications outside of the Annual Planning Cycle (APC) ensuring that they have the necessary functionality and features to support their business processes. Additionally, IT will be able to support changes to business processes, implement hardware upgrades, security patches, and adopt software releases to avoid version obsolescence.	Do nothing - Financial applications will stagnate and will not be running on the latest releases/patches which could impact security, application performance and usability.	Not Applicable	N/A - None of the Finance Application Health initiatives are cloud based.	No	1/2/2023	12/29/2025	$	$ 388,010.87	$ 338,739.68	$ 122,743.46	$ 136,692.00	$ 682.15		$ 78,612.29	$ 26,270.98	$ 23,312.02	$ (1,241.24)	$ 0.21			$ 25,798.13
167	2026	Financial Applications Health	Sustainment	Shared	Corporate Application	Steve Ambrose	DPHD0002474	Level 3	During 2026 through 2028, the Controller's Organization will require ongoing / periodic version upgrades to Power Plan and SAP Business Planning and Consolidation (BPC). Visual Corporate Keeper will be upgraded, and obsolete windows servers will continue to be replaced on a regular cadence amongst the financial applications. 2026 Implement new Cadency level enhancement and perform upgrade on Cadency application. Redhat server upgrade for OneSource integration server. Upgrade PowerPlan application, Oracle database, Hardware. Move Sales Use and Tax historical data off unsupported servers. Prioritize and implement new functionality and features when requested by our financial business partners for the following applications SAP ERP Financial modules, SAP BPC, SAP BW, One Source Sales & Use Tax, PowerPlan, Visual Corporate Keeper, Cadency, Concur, Teamsuite, etc.). Monthly meetings occur with Controllers, Quorum meetings with other business partners to identify and prioritize any enhancements. Leadership from business partners are involved. Ensure that all future security patches are addressed on applications such as (e.g. SAP ERP, SAP BPC, SAP BW, One Source Sales & Use Tax, PowerPlan, Visual Corporate Keeper, Wibeta by Wireless, etc.).	Employee Value - DTE Financial employees will continue to have the the functionality and features required to execute their processes, and will utilize financial applications that remain compliant with Sarbanes Oxley and other compliance requirements that protect DTE from accounting errors and ensure accurate financials. These enhancements further improve efficiencies in the financial close process and improve overall system health. The DTE Financial Organizations will be able to obtain minor enhancements on an annual basis to their applications outside of the Annual Planning Cycle (APC) ensuring that they have the necessary functionality and features to support their business processes. Additionally, IT will be able to support changes to business processes, implement hardware upgrades, security patches, and adopt software releases to avoid version obsolescence.	Do nothing - Financial applications will stagnate and will not be running on the latest releases/patches which could impact security, application performance and usability.	Standard-market-based and/or commoditized non-core energy workload - deploy in commercial cloud	N/A - None of the Finance Application Health initiatives are cloud based.	No	1/2/2026	12/31/2028	$	$ 1,402,063.00	$ 1,413,063.00		$ 220,073.00		$ 1,192,063.00	$ 30,927.00	$ 69,000.00	$ 18,272.16	$ 50,727.84			$ 49,066.00
168	2027	Financial Applications Health	Sustainment	Shared	Corporate Application	Steve Ambrose	DPHD0002474	Level 3	During 2026 through 2028, the Controller's Organization will require ongoing / periodic version upgrades to Power Plan and SAP Business Planning and Consolidation (BPC). Visual Corporate Keeper will be upgraded, and obsolete windows servers will continue to be replaced on a regular cadence amongst the financial applications. 2027 Perform PowerPlan upgrade to support Windows 11. Upgrade VCK application. Move the contract management application to a supported stack. Move historical PeopleSoft data to a newer, supported stack. Prioritize and implement new functionality and features when requested by our financial business partners for the following applications SAP ERP Financial modules, SAP BPC, SAP BW, One Source Sales & Use Tax, PowerPlan, Visual Corporate Keeper, Cadency, Concur, Teamsuite, etc.). Monthly meetings occur with Controllers, Quorum meetings with other business partners to identify and prioritize any enhancements. Leadership from business partners are involved. Ensure that all future security patches are addressed on applications such as (e.g. SAP ERP, SAP BPC, SAP BW, One Source Sales & Use Tax, PowerPlan, Visual Corporate Keeper, Wibeta by Wireless, etc.).	Employee Value - DTE Financial employees will continue to have the the functionality and features required to execute their processes, and will utilize financial applications that remain compliant with Sarbanes Oxley and other compliance requirements that protect DTE from accounting errors and ensure accurate financials. These enhancements further improve efficiencies in the financial close process and improve overall system health. The DTE Financial Organizations will be able to obtain minor enhancements on an annual basis to their applications outside of the Annual Planning Cycle (APC) ensuring that they have the necessary functionality and features to support their business processes. Additionally, IT will be able to support changes to business processes, implement hardware upgrades, security patches, and adopt software releases to avoid version obsolescence.	Do nothing - Financial applications will stagnate and will not be running on the latest releases/patches which could impact security, application performance and usability.	Standard-market-based and/or commoditized non-core energy workload - deploy in commercial cloud	N/A - None of the Finance Application Health initiatives are cloud based.	No	1/2/2026	12/31/2028	$	$ 308,838.68	$ 279,127.68		$ 206,200.00			$ 30,927.00	$ 68,712.00	$ 17,984.24	$ 50,727.84			$ 49,747.40

168	2028	Financial Applications Health	Sustainment	Shared	Corporate Application	Steve Ambrose	DPM0000247A	Level 3	During 2028 through 2028, the Controller's Organization will require ongoing / periodic version upgrades to Power Plan and SAP Business Planning and Consolidation (BPC). Visual Corporate Keeper will be upgraded, and obsolete windows servers will continue to be replaced on a regular cadence amongst the financial applications. 2028 Perform upgrades in Cadency application. Upgrade to a new version of our Regulatory Rebuttal dashboard. Prioritize and implement new functionality and features when requested by our financial business partners for the following applications: Financial Analytics (Power BI), Power Plan, SAP BPC, SAP BW, Visual Corporate Keeper, Oracle Hyperion, Cadency, Cyncsa, Teamsnap, etc.). Monthly meetings occur with Controllers, Avenues meetings with other business partners to identify and prioritize any enhancements. Leadership from business partners are involved. Ensure that all future security patches are addressed on applications such as e.g. SAP BPC, SAP BPC, SAP BW, One Source Sales & Use Tax, PowerPlan, Visual Corporate Keeper, Nitrex by Workiva, etc.).	Employee Value - DTE Financial employees will continue to have the the functionality and features required to execute their processes, and will utilize financial applications that remain compliant with Sarbanes Oxley and other compliance requirements that protect DTE from accounting errors and ensure accurate financials. These enhancements further improve efficiencies in the financial close process and improve overall system health. The DTE Financial Organizations will be able to obtain minor enhancements on an annual basis to their applications outside of the Annual Planning Cycle (Cadency, Cyncsa, Teamsnap, etc.). Minor enhancements are defined as enhancements that require less than 200 hours of effort. These include changes to business processes, implement hardware upgrades, security patches, and adopt software releases to avoid version obsolescence.	Do nothing - Financial applications will degrade and will not be running on the latest releases/patches which could impact security, application performance and usability.	Standard market-based and/or commoditized non-core energy workload - deploy in commercial cloud	N/A - None of the Finance Application Health initiatives are cloud based.	No	1/2/2026	12/31/2028	$ 318,987.88	$ 248,727.00		$ 217,800.00		$ 30,827.00	$ 68,240.88	$ 17,313.04	$ 50,727.84				$ 49,498.40
170	2025	Human Resources Applications Health	Sustainment	Shared	Corporate Application	Steve Ambrose	DPM0000122	Actual	SAP requires yearly upgrades and patching of SuccessFactors to annually to ensure each platform is current and operating with the latest functions and features to support business processes. Bug fixes, Enhancements, and Changes are regularly deployed to support HR, Legal and Ethics and Compliance business process. Changes are documented, reviewed, estimated, and prioritized monthly with BU Leadership and Subject Matter Experts. Prioritized changes are scoped, resourced, and provide with an implementation timeline. Deployment includes DTE and Vendor support. This project is to sustain operations that meet standard service level objectives that are supported by the team for the enterprise Applications in its span of control. If we lose support, we will no longer receive security patches increasing our risk of experiencing security incidents.	The value of this investment ensure that we are able to maintain current levels of software at all levels, support operational hardware, environment upgrades, and security patches and keep the HR systems up-to-date. These are imperative to system health and meeting the business' objectives for DTE.	HR applications will degrade and will not be running on the latest releases/patches which could impact security, application performance and usability.	Core energy management or cyber osecurity system - stay on premise	Success Factors is in alignment with our technology platform plan which is currently in place.	No	1/2/2023	12/31/2025	$ 392,891.00	$ 308,215.33	$ 97,365.85	$ 137,037.84	$ 715.55		$ 75,096.39	$ 84,835.48	$ 50,898.28	$ 10,582.00	$ 1,139.02	$ 49.49		$ 63,431.47
171	2026	Human Resources Applications Health	Sustainment	Shared	Corporate Application	Steve Ambrose	DPM0000242A	Level 3	The Human Resources Application Health budget is critical as it provides continued support of the over 30 applications Human Resources, Legal and Ethics and Compliance portfolio. The support plan is to follow a consistent schedule of deployments and releases that are defined based on previous year and repeated for the 3 years. 2026 SAP requires yearly upgrades and patching of SuccessFactors to annually to ensure each platform is current and operating with the latest functions and features to support business processes. Bug fixes, Enhancements, and Changes are regularly deployed to support HR, Legal and Ethics and Compliance business process. Changes are documented, reviewed, estimated, and prioritized monthly with BU Leadership and Subject Matter Experts. Prioritized changes are scoped, resourced, and provide with an implementation timeline. Deployment includes DTE and Vendor support. This funding also covers certification management, vulnerability mitigation and system patching.	The value of this investment ensure that we are able to maintain current levels of software at all levels, support operational hardware, environment upgrades, and security patches and keep the HR systems up-to-date. These are imperative to system health and meeting the business' objectives for DTE.	HR applications will degrade and will not be running on the latest releases/patches which could impact security, application performance and usability.	Core energy management or cyber osecurity system - stay on premise	Success Factors is in alignment with our technology platform plan which is currently in place.	No	1/2/2026	12/31/2028	$ 398,065.76	$ 337,275.53	$ 216,109.02				$ 121,166.00	$ 50,728.25	$ 50,728.25	$ -				$ 36,737.05
172	2027	Human Resources Applications Health	Sustainment	Shared	Corporate Application	Steve Ambrose	DPM0000242B	Level 3	The Human Resources Application Health budget is critical as it provides continued support of the over 30 applications Human Resources, Legal and Ethics and Compliance portfolio. The support plan is to follow a consistent schedule of deployments and releases that are defined based on previous year and repeated for the 3 years. 2027 SAP requires yearly upgrades and patching of SuccessFactors to annually to ensure each platform is current and operating with the latest functions and features to support business processes. Bug fixes, Enhancements, and Changes are regularly deployed to support HR, Legal and Ethics and Compliance business process. Changes are documented, reviewed, estimated, and prioritized monthly with BU Leadership and Subject Matter Experts. Prioritized changes are scoped, resourced, and provide with an implementation timeline. Deployment includes DTE and Vendor support. This funding also covers certification management, vulnerability mitigation and system patching. This demand is to sustain operations that meet standard service level objectives that are supported by the team for the enterprise Applications in its span of control. If we lose support, we will no longer receive security patches increasing our risk of experiencing security incidents.	The value of this investment ensure that we are able to maintain current levels of software at all levels, support operational hardware, environment upgrades, and security patches and keep the HR systems up-to-date. These are imperative to system health and meeting the business' objectives for DTE.	HR applications will degrade and will not be running on the latest releases/patches which could impact security, application performance and usability.	Core energy management or cyber osecurity system - stay on premise	Success Factors is in alignment with our technology platform plan which is currently in place.	No	1/2/2026	12/31/2028	$ 387,098.73	$ 337,198.73	$ 215,642.71				$ 121,166.00	$ 50,588.00	$ 50,588.00					$ 36,629.71
173	2028	Human Resources Applications Health	Sustainment	Shared	Corporate Application	Steve Ambrose	DPM0000242B	Level 3	The Human Resources Application Health budget is critical as it provides continued support of the over 30 applications Human Resources, Legal and Ethics and Compliance portfolio. The support plan is to follow a consistent schedule of deployments and releases that are defined based on previous year and repeated for the 3 years. 2028 SAP requires yearly upgrades and patching of SuccessFactors to annually to ensure each platform is current and operating with the latest functions and features to support business processes. Bug fixes, Enhancements, and Changes are regularly deployed to support HR, Legal and Ethics and Compliance business process. Changes are documented, reviewed, estimated, and prioritized monthly with BU Leadership and Subject Matter Experts. Prioritized changes are scoped, resourced, and provide with an implementation timeline. Deployment includes DTE and Vendor support. This funding also covers certification management, vulnerability mitigation and system patching. This demand is to sustain operations that meet standard service level objectives that are supported by the team for the enterprise Applications in its span of control. If we lose support, we will no longer receive upgrades, maintenance, and security patches increasing our risk of experiencing security incidents.	The value of this investment ensure that we are able to maintain current levels of software at all levels, support operational hardware, environment upgrades, and security patches and keep the HR systems up-to-date. These are imperative to system health and meeting the business' objectives for DTE.	HR applications will degrade and will not be running on the latest releases/patches which could impact security, application performance and usability.	Core energy management or cyber osecurity system - stay on premise	Success Factors is in alignment with our technology platform plan which is currently in place.	No	1/2/2026	12/31/2028	$ 387,402.33	$ 337,412.33	$ 216,246.55				$ 121,166.00	$ 50,070.00	$ 50,070.00					$ 36,250.68
174	2025	Production Growth	Sustainment	Shared	Corporate Application	Steve Ambrose	DPM0000122S1	Actual	This investment is intended to provide the ability to support business growth of the Corporate Applications portfolio (corporate applications (covers LLC business units such as Supply Chain, Finance, Human Resources, et al.). The annual server storage, capacity, and memory growth for the Corporate Application portfolio each year since 2020 was approximately 1.5 TB storage and 10 GB of memory across all environments (test and development). The portfolio memory and storage continue to grow on an annual basis. To ensure the platform and associated applications continue to function as intended, this investment is critical as it covers the costs for computing power, storage capacity, database availability and middle tier infrastructure.	This capital investment enables sustained business growth by expanding and modernizing the underlying infrastructure supporting the Corporate Applications portfolio, which serves critical enterprise functions across Supply Chain, Finance, Human Resources, and other LLC business units. As application usage and data volumes continue to grow, incremental increases in server storage, memory, and computing capacity are required to maintain reliable system performance and availability. By proactively funding infrastructure growth on a yearly basis, the enterprise avoids larger, unplanned capital expenditures driven by capacity constraints or system failure. This approach preserves asset value, supports predictable expansion of enterprise capabilities, and ensures the Corporate Applications portfolio remains aligned with evolving business requirements, regulatory obligations, and long-term operational scalability.	Do Nothing is not an option. Applications performance and availability would be critically impacted. Failure to invest in the continued growth of the platform and associated application infrastructure would compromise functionality of the supported assets as database availability, CPU, server storage, etc. would be consumed and negatively impact performance.	Does not follow cloud computing strategy. - exception	cloud computing strategy. Portions of EBS (Successfactors, myDTE) are cloud-based. Remaining portions of EBS	Yes	1/2/2026	12/31/2026	$ 543,868.89	$ 450,484.12	$ 66,316.44	$ 27,600.00	$ 277,107.68		$ 79,010.00	$ 93,464.73	$ 83,864.73	$ 9,800.00				$ 67,625.02
175	2026	Production Growth	Sustainment	Shared	Corporate Application	Steve Ambrose	DPM0000247A	Level 3	Approved in U-21046																					
176	2027	Production Growth	Sustainment	Shared	Corporate Application	Steve Ambrose	DPM0000247B	Level 3	This investment is intended to provide the ability to support business growth of the Corporate Applications portfolio (corporate applications (covers LLC business units such as Supply Chain, Finance, Human Resources, et al.). The annual server storage, capacity, and memory growth for the Corporate Application portfolio each year since 2020 was approximately 1.5 TB storage and 10 GB of memory across all environments (test and development). The portfolio memory and storage continue to grow on an annual basis. To ensure the platform and associated applications continue to function as intended, this investment is critical as it covers the costs for computing power, storage capacity, database availability and middle tier infrastructure. 2027 This investment is intended to provide the ability to support business growth of the Corporate Applications portfolio (corporate applications (covers LLC business units such as Supply Chain, Finance, Human Resources, et al.). The annual server storage, capacity, and memory growth for the Corporate Application portfolio each year since 2020 was approximately 1.5 TB storage and 10 GB of memory across all environments (test and development). The portfolio memory and storage continue to grow on an annual basis. To ensure the platform and associated applications continue to function as intended, this investment is critical as it covers the costs for computing power, storage capacity, database availability and middle tier infrastructure. Each year, in addition to storage and memory growth, the scope of investment is determined by the applications listed above (e.g.) which require additional resources, hardware capacity, or renewal of long-term licensing.	This capital investment enables sustained business growth by expanding and modernizing the underlying infrastructure supporting the Corporate Applications portfolio, which serves critical enterprise functions across Supply Chain, Finance, Human Resources, and other LLC business units. As application usage and data volumes continue to grow, incremental increases in server storage, memory, and computing capacity are required to maintain reliable system performance and availability. By proactively funding infrastructure growth on a yearly basis, the enterprise avoids larger, unplanned capital expenditures driven by capacity constraints or system failure. This approach preserves asset value, supports predictable expansion of enterprise capabilities, and ensures the Corporate Applications portfolio remains aligned with evolving business requirements, regulatory obligations, and long-term operational scalability.	Do Nothing is not an option. Applications performance and availability would be critically impacted. Failure to invest in the continued growth of the platform and associated application infrastructure would compromise functionality of the supported assets as database availability, CPU, server storage, etc. would be consumed and negatively impact performance.	Does not follow cloud computing strategy. - exception	cloud computing strategy. Portions of EBS (Successfactors, myDTE) are cloud-based. Remaining portions of EBS	Yes	1/2/2026	12/31/2028	$ 543,868.89	$ 450,484.12	$ 66,316.44	$ 27,600.00	$ 277,107.68		$ 79,010.00	$ 93,464.73	$ 83,864.73	$ 9,800.00				$ 67,625.02
177	2028	Production Growth	Sustainment	Shared	Corporate Application	Steve Ambrose	DPM0000247C	Level 3	This investment is intended to provide the ability to support business growth of the Corporate Applications portfolio (corporate applications (covers LLC business units such as Supply Chain, Finance, Human Resources, et al.). The annual server storage, capacity, and memory growth for the Corporate Application portfolio each year since 2020 was approximately 1.5 TB storage and 10 GB of memory across all environments (test and development). The portfolio memory and storage continue to grow on an annual basis. To ensure the platform and associated applications continue to function as intended, this investment is critical as it covers the costs for computing power, storage capacity, database availability and middle tier infrastructure. 2028 This investment is intended to provide the ability to support business growth of the Corporate Applications portfolio (corporate applications (covers LLC business units such as Supply Chain, Finance, Human Resources, et al.). The annual server storage, capacity, and memory growth for the Corporate Application portfolio each year since 2020 was approximately 1.5 TB storage and 10 GB of memory across all environments (test and development). The portfolio memory and storage continue to grow on an annual basis. To ensure the platform and associated applications continue to function as intended, this investment is critical as it covers the costs for computing power, storage capacity, database availability and middle tier infrastructure. Each year, in addition to storage and memory growth, the scope of investment is determined by the applications listed above (e.g.) which require additional resources, hardware capacity, or renewal of long-term licensing.	This capital investment enables sustained business growth by expanding and modernizing the underlying infrastructure supporting the Corporate Applications portfolio, which serves critical enterprise functions across Supply Chain, Finance, Human Resources, and other LLC business units. As application usage and data volumes continue to grow, incremental increases in server storage, memory, and computing capacity are required to maintain reliable system performance and availability. By proactively funding infrastructure growth on a yearly basis, the enterprise avoids larger, unplanned capital expenditures driven by capacity constraints or system failure. This approach preserves asset value, supports predictable expansion of enterprise capabilities, and ensures the Corporate Applications portfolio remains aligned with evolving business requirements, regulatory obligations, and long-term operational scalability.	Do Nothing is not an option. Applications performance and availability would be critically impacted. Failure to invest in the continued growth of the platform and associated application infrastructure would compromise functionality of the supported assets as database availability, CPU, server storage, etc. would be consumed and negatively impact performance.	Does not follow cloud computing strategy. - exception	cloud computing strategy. Portions of EBS (Successfactors, myDTE) are cloud-based. Remaining portions of EBS	Yes	1/2/2028	12/31/2028	$ 543,396.75	$ 451,834.63	$ 64,715.15	$ 26,200.00	$ 281,608.68		$ 79,010.00	$ 93,584.72	$ 82,364.72	$ 9,400.00				$ 68,292.88
178	2026	Production Growth	Sustainment	Shared	Corporate Application	Steve Ambrose	DPM0000247D	Level 3	Approved in U-21046																					
179	2025	Cloud Health and Safety	Return-to-Health	Shared	Corporate Application	Steve Ambrose	DPM0000146K	Actual	Current DTE safety reporting systems are not integrated, and safety related metrics are predominantly lagging in nature. Moreover, incidents created in multiple systems, lack robust workflow engine, etc. DTE lists how many facilities in place for incident & near-miss tracking. DTE stores pdfs* in 3 different systems which create missed opportunities for catching leading indicators. DTE has systems housing sensitive employee data which do not utilize DTE defined security roles. The multiple systems are used throughout the corporation to capture, store and report safety information, these systems are not user friendly, promoting ground and detailed trending and root cause analysis. Increase accuracy, sufficient details, timely reporting, and sharing for prompt compliance. SAP EH&S will now become a cloud-based SaaS SAP solution enable a fully integrated cloud-based solution that integrates directly with ECC and Q-Workflow. This transformation will be executed through a phased implementation of SAP Ariba and Fieldglass modules, delivering a fully integrated Procure-to-Pay (P2P) ecosystem. The solution will provide modern tools and technologies to support end-to-end business processes including tracking, sourcing, requisitioning, ordering, receiving, payment, and work management. Key capabilities will include APIs, external bidding portals, vendor onboarding, safety and quality tracking, and supplier performance management.	Provide our employees a simple, single point of access for all safety related reporting and data analysis, intuitively designed to reduce training needs. The layered safety data analytics would provide leaders visibility to measurable changes in their safety KPIs through actionable safety data analysis tailored to their work group. A fluid and comfortable accident reporting software encourages employment engagement, increases the accuracy of data collected, allows for proper case and help, increases the effectiveness of the investigation process, removes administrative, routine tasks, encourages Self-Service, provides a standardized message to the enterprise, streamlines training recommendations, increases Sharing lessons learned, provides insight on Corrective Actions) Effectiveness, and reduces Injury and Incidents. Reduce Lost Productivity (~$0.3 million): Centralized CAPA (corrective and preventative action) system for all incident types to make remediation more streamlined. • Repurpose Health and Safety Staff Time (~$0.4 million): Reduction in manual work, and avoidable seeking and manipulation of data • Reduce IT Support Costs (~$1.5 million): IT Support Costs of application and interface support for the landscape of safety apps in use at DTE today	Reviewed migrating the custom developed in-house application from SCTorio 1.0 to SCTorio 2.0 cloud for incident response capabilities. Due to the complexity and integration with HR information, the migration of the custom developed system and cost of enhancement outweighed the initial expenses in the short term and year-over-year costs for maintenance. The SAP SCTorio solution is already integrated with the system's used to manage human resources information and meets DTE's needs for incident response with very little customization.	Specialized workload - stay on premise	SAP SCTorio Cloud is already in place and meets DTE cloud technology requirements.	Yes	1/2/2024	6/30/2025	$	$ 519,339.69	$ 521,749.97	$ 314,696.51	$ 329,825.69	$ 1,298.17	$ (173,241.39)	$ 208,967.92	$ (2,410.86)	$ (154.88)	$ (2,256.00)				$ (1,590.88)
179	2026	Compensation, Time Entry and Payroll Implementation	Return-to-Health	Shared	Corporate Application	Steve Ambrose	DPM0000583S	Level 3	SAP Human Resources SuccessFactors Compensation, Workforce Solutions Dimension Time, and Payroll SAP applications are a fully integrated cloud-based solution that integrates with SAP S4 Hana and aligns with the DTE Strategic Core-ERP Platform Strategy specification of SAP platform. The solution will be utilized across the enterprise by both Gas and Electric Business Units. ITS, in collaboration with its Human Resource partners, will implement the SuccessFactors Compensation, Workforce Solutions Dimension Time and Payroll SAP application. This project, running from 2026 to 2029 will transition the current SAP HR ERP legacy system to a cohesive cloud-based enterprise solution. The SAP Time Management application by Workforce will serve as the system of record for Time Management, integrating with various business unit interfaces and third-party systems. Procurement and planning will commence in 2026, followed by design and build phases in 2027-2028, and concluding with deployment in 2029. The Success Factors Compensation module offers features like visual employee comparisons, configurable worksheets, bonus forecasting, while streamlining compensation processes and reduce HR process complexity.	DTE Energy will invest in the SAP Employee Central Payroll and Time solution and will replace the current SAP ERP on-premises solution implemented in 2007. Requirements and discovery sessions will be conducted to define a path forward to successfully implementing the solution in 2027/2028	Standard market-based and/or commoditized non-core energy workload - deploy in commercial cloud	usage status and reliability which are cloud based internally. These maps will be a part of the bigger picture for b	No	2/9/2026	7/31/2029	$	$ 4,269,862.24	$ 3,598,986.75	$ 791,560.65	$ 2,240,099.10			$ 655,425.50	$ 669,862.49	$ 347,457.77	$ 338,404.72				$ 498,964.64
180	2027	Compensation, Time Entry and Payroll Implementation	Return-to-Health	Shared	Corporate Application	Steve Ambrose	DPM0000583S	Level 3	SAP Human Resources SuccessFactors Compensation, Workforce Solutions Dimension Time, and Payroll SAP applications are a fully integrated cloud-based solution that integrates with SAP S4 Hana and aligns with the DTE Strategic Core-ERP Platform Strategy specification of SAP platform. The solution will be utilized across the enterprise by both Gas and Electric Business Units. ITS, in collaboration with its Human Resource partners, will implement the SuccessFactors Compensation, Workforce Solutions Dimension Time and Payroll SAP application. This project, running from 2026 to 2029 will transition the current SAP HR ERP legacy system to a cohesive cloud-based enterprise solution. The SAP Time Management application by Workforce will serve as the system of record for Time Management, integrating with various business unit interfaces and third-party systems. Procurement and planning will commence in 2026, followed by design and build phases in 2027-2028, and concluding with deployment in 2029. The Success Factors Compensation module offers features like visual employee comparisons, configurable worksheets, bonus forecasting, while streamlining compensation processes and reduce HR process complexity.	DTE Energy will invest in the SAP Employee Central Payroll and Time solution and will replace the current SAP ERP on-premises solution implemented in 2007. 2027/2028 - Cloud based payroll and time systems will be implemented, modernizing the platform and reducing long term operational risk. Pay frequency will shift from biweekly to semi monthly to streamline payroll processing, with weekly pay introduced as an additional flexible option.	Standard market-based and/or commoditized non-core energy workload - deploy in commercial cloud	usage status and reliability which are cloud based internally. These maps will be a part of the bigger picture for b	No	2/9/2026	7/31/2029	$	$ 4,105,349.25	$ 3,350,519.66	$ 2,540,422.96	$ 66,969.00			$ 742,797.00	$ 754,829.30	$ 385,233.06	$ 369,614.24				$ 546,496.41
181	2028	Compensation, Time Entry and Payroll Implementation	Return-to-Health	Shared	Corporate Application	Steve Ambrose	DPM0000583S	Level 3	SAP Human Resources SuccessFactors Compensation, Workforce Solutions Dimension Time, and Payroll SAP applications are a fully integrated cloud-based solution that integrates with SAP S4 Hana and aligns with the DTE Strategic Core-ERP Platform Strategy specification of SAP platform. The solution will be utilized across the enterprise by both Gas and Electric Business Units. ITS, in collaboration with its Human Resource partners, will implement the SuccessFactors Compensation, Workforce Solutions Dimension Time and Payroll SAP application. This project, running from 2026 to 2029 will transition the current SAP HR ERP legacy system to a cohesive cloud-based enterprise solution. The SAP Time Management application by Workforce will serve as the system of record for Time Management, integrating with various business unit interfaces and third-party systems. Procurement and planning will commence in 2026, followed by design and build phases in 2027-2028, and concluding with deployment in 2029. The Success Factors Compensation module offers features like visual employee comparisons, configurable worksheets, bonus forecasting, while streamlining compensation processes and reduce HR process complexity.	DTE Energy will invest in the SAP Employee Central Payroll and Time solution and will replace the current SAP ERP on-premises solution implemented in 2007. 2027/2028 - Cloud based payroll and time systems will be implemented, modernizing the platform and reducing long term operational risk. Pay frequency will shift from biweekly to semi monthly to streamline payroll processing, with weekly pay introduced as an additional flexible option.	Standard market-based and/or commoditized non-core energy workload - deploy in commercial cloud	usage status and reliability which are cloud based internally. These maps will be a part of the bigger picture for b	No	2/9/2026	7/31/2029	$	$ 2,598,539.11	$ 1,845,325.35	$ 774,671.15	$ 328,457.20			$ 742,797.00	$ 751,213.76	$ 382,288.52	$ 368,914.24				$ 543,878.76
182	2026	Environmental Air Regulation Management	Return-to-Health	Shared	Corporate Application	Steve Ambrose	DPM0000159R	Actual	Approved in U-21469																					
183	2026	Environmental Air Regulation Management	Return-to-Health	Shared	Corporate Application	Steve Ambrose	DPM0000159R	Level 3	Replace the existing on-premise application with a new application that supports the current and future air and greenhouse gas emissions reporting requirements. Environmental will be upgrading Sphera Cloud Application to support Environmental Air Regulation. Sphera will be able to manage emissions calculations and other compliance demonstrations as well as prepare DTE sustainability regulatory reporting. Scope for 2026 Complete development, testing, training and deployed solution	The current reliance on an obsolete, non -upgradable system requires extensive manual effort and external consulting support, driving higher costs and increasing the risk of errors in regulatory filings. Replacing the legacy solution with the Sphera Cloud platform enables standardized, automated, and auditable reporting processes, improving accuracy and reliability across more than sixty required reports annually. The investment positions DTE to meet evolving regulatory requirements more efficiently while supporting consistent, resilient, and cost -effective operations for customers and stakeholders.	The Cypsela air application requirements, Sphera Cloud, has been reviewed by the environmental organization. The team will utilize other big quantitative regulatory compliance applications for their air emissions reporting capabilities and have chosen SAP products for Human Resource Capital Management (HCM) Utilizing SAP products for the entire HCM program (Core HR, talent management, data collection, scheduling, and timekeeping) across the Company will minimize interface and data integration problems. Maintaining one SAP platform ensures the ability to upgrade the application or operating environment is not an option and could result in non-compliance and possible vulnerabilities.	Specialized workload - stay on premise	The application will be migrated to a Saas solution which meets all security and cloud computing guidelines.	No	9/15/2025	4/30/2026	$	$ 188,088.88	$ 152,998.88	$ 8,675.96	$ 125,242.28			$ 19,082.00	$ 14,000.00	$ 3,890.00	$ 3,420.00		$ 7,069.00		$ 10,136.00
184	2027	Powerplan PowerTax Upgrade	Return-to-Health	Shared	Corporate Application	Steve Ambrose	DPM0000920S	Level 3	The recommended solution is to upgrade PowerTax to Lucanet. The PowerTax is going end of life in December 2027 with no option to pay premium for support thereafter. It is critical to get this upgraded to a supported version to avoid any financial risk.	This business function ensures that tax is calculated correctly on all of our major assets. This would be a huge risk to DTE if this capability was being run on an unsupported application.	Do nothing result in significant premium needed to support the system for another two years and hence is not considered as an effective solution since the extended premium support will end after the two years and the application will be completely unsupported.	Core energy management or cyber osecurity system - stay on premise			No	1/2/2027	12/31/2027	$	$ 795,098.10	$ 284,744.06	$ 42,919.06	$ 140,400.00			$ 41,425.00	$ 500,902.04	$ 3,352.04	$ 29,600.00		$ 468,000.00		$ 362,049.28
185	2027	Powerplan Upgrade	Return-to-Health	Shared	Corporate Application	Steve Ambrose	DPM0000245U	Level 3	PowerPlan is a key business application for our accounting team, ensuring depreciation of all our more than $20 billion of assets get depreciated correctly. The current version PowerPlan will reach its EOS and needs to be updated to ensure support and compliance that our depreciation is being performed accurately. By end of 2027, we will no longer be able to pay premium for support	PowerPlan is the Company's Fixed Asset Financial Accounting System and is a key SOX asset for the Finance Organization. This upgrade is critical to ensure system stability, reliability, and speed of processing financial transactions. The company cannot take the risk of running this application unsupported. The financial impact if not being able to efficiently track and depreciate all our fixed assets is huge.	If we do nothing, we will have a risk of trying to depreciate over $40 billion of assets on an application that is not supported. If something goes wrong and cannot be fixed, this will cause major general accounting issues.	Does not follow cloud computing strategy. - exception	n-ee upgrade, we will also move it to DTE's cloud, which will enable an easier upgrade to PowerPlan's SaaS solut	Yes	1/2/2027	12/31/2027	$	$ 1,822,758.76	$ 1,284,488.31	$ 110,745.15	$ 1,121,000.00			$ 146,753.10	$ 438,260.45	$ 261,260.45	$ 177,000.00				$ 317,269.37
186	2026	Industrial Hygiene	Strategic	Shared	Corporate Application	Steve Ambrose	DPM0000361N	Level 3	Approved in U-21469																					
187	2027	Real Estate Management	Strategic	Electric	Corporate Application	Steve Ambrose	DPM0000122J	Level 3	The Real Estate Management project will implement the SAP Capital Lease Management (CLM) module and integrate it with existing systems, including SAP Employee Central Component, Decarbonet, and the future SAP S/4 HANA platform. This integration will streamline lease data management, ensure compliance with lease accounting standards, automate processes, enhance productivity and support sustainable property portfolio management, improve collaboration with Corporate Legal, Tax, Renewable Energy, Gas, and Electric Field personnel.	This Solution will provide DTE with the latest digital technologies to streamline and enhance real estate management processes with the contract and lease management software S-4 Hanna module for contract, lease, and real estate management.	Corporate Real Estate currently uses Excel (and sales contract and county records) to track property information. This is time consuming and creates the risk of up-to-date records causing confusion and delays in projects.	Core energy management or cyber osecurity system - stay on premise	SAP S-4 Hanna Real Estate Modules is in cloud.	No	2/1/2027	7/31/2027	$	$ 2,831,733.33	$ 2,571,147.23	$ 148,205.35	$ 852,000.00		$ 1,388,912.50	$ 201,029.40	$ 260,586.10	$ 48,586.10	$ 212,000.00				$ 260,586.10
188	2027	Source to Pay (S2P) Transformation	Strategic	Shared	Corporate Application	Steve Ambrose	DPM0000152W	Level 3	To modernize and streamline procurement processes, DTE is transitioning from legacy systems to a modern SAP platform with a cloud-based solution that integrates directly with ECC and Q-Workflow. This transformation will be executed through a phased implementation of SAP Ariba and Fieldglass modules, delivering a fully integrated Procure-to-Pay (P2P) ecosystem. The solution will provide modern tools and technologies to support end-to-end business processes including tracking, sourcing, requisitioning, ordering, receiving, payment, and work management. Key capabilities will include APIs, external bidding portals, vendor onboarding, safety and quality tracking, and supplier performance management. The tentative breakdown of the implementation schedule is as follows. 2027 - Q1 and Q2: Development and design of Ariba Module Commerce Automation Module Q3 and Q4: Implementation Ariba Commerce Automation Modules. Start Planning for Ariba Buying and Invoicing, Catalog Management, Value Analysis Ariba Modules. 2028 - Q1 and Q2: Implement Buying and Invoicing, Catalog Management, Value Analysis Ariba Modules. Start planning for Fieldglass Services and Contingent Labor Ariba Modules. Q3 and Q4: Implement Fieldglass Services and Contingent Labor Modules. Begin planning for Sourcing, Contracts, and Supplier Qu	Modernizing the procurement to pay process with SAP Ariba is essential to ensuring ITS can effectively support DTE's evolving operational requirements and strategic growth objectives while maintaining regulatory compliance and delivering value to customers.	Alternatives considered: Do nothing - using SRM unsupported would be a catastrophic risk to the business operations and would violate audit and SOX controls. The risk would increase every day. If we executed an enterprise-wide scale stoppage, if the project is not completed by 2, we encounter enterprise-wide scale stoppage. If the project is not completed by 2028, the annual licensing cost will increase by an estimated 25%	Core energy management or cyber osecurity system - stay on premise	The product selected will be a SaaS solution which provides integrated with SAP S4 Cloud connectors.	No	1/2/2027	12/31/2029	$	$ 5,126,442.11	$ 4,593,961.40	$ 758,450.40	$ 3,069,000.00			$ 839,513.30	$ 539,476.71	$ 108,676.71	$ 426,800.00				$ 387,886.06

189	2028	Source to Pay (S2P) Transformation	Strategic	Shared	Corporate Application	Steve Ambrose	OPHD0001230	Level 3	To modernize and streamline DTE's procurement operations, this will replace the outdated SAP ERP platform with a cloud-based solution that integrates directly with ECC and S/4HANA. This transformation will be executed through a phased implementation of SAP Ariba and Fieldglass modules, delivering a fully integrated Procure-to-Pay (P2P) ecosystem. The solution will provide modern tools and technologies to support end-to-end business processes including hunting, sourcing, requisitioning, ordering, receiving, payment, and work management. Key capabilities will include APIs, external bidding portals, vendor onboarding, safety and quality tracking, and supplier performance management. The tentative breakdown of the implementation schedule is as follows. 2027 - Q1 and Q2: Development and design of Ariba Module Commerce Automation Module Q3 and Q4: Implementation Ariba Commerce Automation Module; Start Planning for Ariba Buying and Invoicing, Catalog Management, Value Analysis Ariba Modules. 2028 - Q1 and Q2: Implement Buying and Invoicing, Catalog Management, Value Analysis Ariba Modules; Start planning for Fieldglass Services and Contingent Labor Ariba Modules.	DTE is modernizing its Procure to Pay process to effectively support large scale electric grid and natural gas infrastructure investments. Implementing SAP Ariba as the enterprise Source to Pay solution will improve transparency, strengthen financial controls, and provide real-time insights into spend and supplier performance. This modernization reduces cycle times and administrative effort while enabling compliant, efficient execution of critical energy programs.	Alternatives considered: 1. Do nothing - using ERP unsupported would be a catastrophic risk to the business and the organization that we are unwilling to take. If it falls without the resources to fix it, we encounter enterprise-wide work stoppage. If the project is not completed by 2028, the annual licensing cost will increase by an estimated 25%. 2. Upgrade to SAP Ariba 3. Market test - send RFP to market leaders to ascertain best solution providing the most value per dollar. The team chose the third alternative. RFP was sent to the four industry leaders: Ariba, Coupa, Ivalua, Jaggaer and bids evaluated in May of 2022. After reviewing the proposals and bids, Ariba was selected. Ariba's ease of integration with our existing architecture and supply chain, team has decided to select Ariba as the ERM replacement. Ariba was chosen as the best fit for the project. Accenture was chosen as the integrator.	Core energy management or cyber overcurly system - stay on premise	The product selected will be a SaaS solution which provides integrated with SAP S4 Cloud connectors.	No	1/2/2027	12/31/2029	$ 5,125,674.92	$ 4,594,038.38	$ 756,525.91	$ 2,998,989.98		$ 835,512.72	$ 521,838.32	$ 198,836.33	$ 424,900.00				$ 364,904.70
190	2025	Warehouse Efficiency	Strategic	Shared	Corporate Application	Steve Ambrose	OPHD0001230	Actual	Utilize bar coding scanning technologies to facilitate accurate reordering of vendor supplied materials at the service centers. Implement technology to augment the SAP ERM's capabilities for tracking and manage direct ship and warehouse transfer transactions. Implement technology to automate the transportation of materials between the warehouse and the field service centers and contractor locations with the equipment needed to facilitate the use of these technologies. Implement reporting capabilities that assist planning and scheduling with material availability.	The Warehouse Efficiency initiative modernizes material tracking through barcoding, RFID, and enhanced SAP inventory capabilities, providing real-time visibility into materials across warehouses and contractor sites. This improves planning and scheduling, reduces stockpiling and delays, and strengthens supply chain reliability to support timely execution of critical electric and gas infrastructure work.	The SAP ECC and ERM capabilities were reviewed as options for assisting in the management inventory at the contracted yards as well as supporting re-ordering of stock materials. The SAP products do not have the capabilities needed to support the Warehouse Efficiency. The alternatives considered are direct ship to the warehouse. Some materials are direct shipped to our contractor to streamline job completion. The availability of the direct ship materials and DTE Warehouse stock materials are tracked in the SAP system to ensure the right materials are scheduled. Do not have ability to track availability of pickup materials. The result is continued duplicate of expenses items such as transformers in contractor yards and delays in customer installations. The alternatives and technologies outlined will supplement the information and streamline process not available with our current technology.	Not Applicable	ne of SAP. When the application is migrated to an external S4 Hana the functionality will be migrated as well. Chi	Yes	1/3/2024	3/31/2025	$ 407,674.39	$ 376,452.08	$ 296.38	$ 323,346.52	$ 1,188.08		$ 53,631.02	$ 88,221.55	$ 234.04	$ 40,464.74	$ 522.73	$ 40,000.50		$ 62,829.77
191	2025	Advance Metering Infrastructure (AMI) Application Health	Sustainment	Shared	Plant and Field	Steve Ambrose	OPHD0001365	Actual																						
192	2025	ClockSoft Application Health	Sustainment	Shared	Plant and Field	Steve Ambrose	OPHD0001371	Actual																						
193	2026	CisCoSoft Application Health	Sustainment	Shared	Plant and Field	Steve Ambrose	OPHD0001387	Level 3																						
194	2025	Distribution Operations Application Health	Sustainment	Electric	Plant and Field	Steve Ambrose	OPHD0001390	Actual																						

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195	2026	Distribution Operations Application Health	Sustainment	Electric	Plant and Field	Steve Ambrose	OPHD0001464	Level 3	The DO Application Health project is a multi-year initiative supporting approximately 50+ supported applications within Distribution Operations (DO). The project includes adding new functionalities to systems such as Crew Management and Storm Restoration System to enhance operational efficiency, improve data accuracy, and provide better tools for field workers. Planned improvements include a redesigned Outage Status App with a Supervisory Dashboard, enhancements to the Mobile Timesheet System, and infrastructure updates. These changes aim to improve customer and employee experiences, streamline workflows, and ensure compliance with regulatory standards. The DO portfolio includes about 50 supported applications that constantly require a significant level of IT support throughout the years. Historically, there are various solutions needed based on the changing landscape of field operations the business groups using these applications supported by IT. - Add new and significant functionality to Crew Management systems that supports work groups other than Overhead and Underground. These changes must accommodate new requirements that support their needs. - Add new functionality to the Storm Restoration System that will accommodate the new roles implemented in the new Outage Manage System. - Continue to add new work groups based on new requirements for Crew Management system Redesign the Outage Status App to accommodate a Supervisory Dashboard that provides a summary of crew assignments, locations, composition dispatched for outage and restoration work. 2025 – Continue work on the Supervisory Dashboard based on new requirements resulting from the ADMS implementation 2025 – Mobile Data Terminals (MDTs)/Cell phone & Tablets Upgrades and code the new Mobile Timesheet System which will add new functionality that supports the rollout of the Advanced Distribution Management System (ADMS) 2025 - Design and implement a new redesigned Outage Status App to replace the current Restore Timesheet System. Redesign and provide the functionality 2024 –Mobile Data Terminals (MDTs) (iCom phones & Tablets 2025 – Mobile Data Terminals (MDTs/ruggers) (iCom phones & Tablets We have established a monthly release schedule for requested changes totaling about ten occurrences per year. The following were to be included in these releases based on historical data: Upgrades to operating systems Replacement of end of life servers Migrating apps from end-of-life systems/platforms Production growth (extra memory, hard drive space,...) Minor enhancements to various DO IT supported apps Power BI development of reports and dashboards	The values realized is an improved customer and employee experience. These improvements will target our mobile applications used by DO field workers for status and complete customer restoration work completed by both employees and contractors. This investment is an ongoing effort important because our business partners regularly review and enhance their processes to benefit the customers, and ask us to accommodate for them programmatically.	It is critical that we capture business process changes in all associated systems to avoid manual workarounds which add operational overhead. There are no alternatives to supporting our business partners in their effort to improve systems that benefit DTE customers. It is critical that we capture business process changes in all associated systems to avoid manual workarounds which add operational overhead.	Specialized workload - stay on premise	The use of cloud computing will be reviewed and approved by Tech and Arch group where applicable.	No	1/2/2026	12/31/2026	$ 3,570,673.35	$ 3,216,785.45	$ 801,819.45	$ 1,951,000.00		$ 569,366.00	$ 51,897.00	$ 9,367.00	$ 40,500.00		$ 2,000.00		$ 51,897.00
196	2027	Distribution Operations Application Health	Sustainment	Electric	Plant and Field	Steve Ambrose	OPHD0003637	Level 3	The DO portfolio includes about 50 supported applications that may require some level of Information Technology enhancements throughout the year. Historically, there are various solutions needed based on the changing landscape of field operations. These enhancement dollars for DO are not meant to fund a single, known solution. The dollars have been historically used for significant enhancements to DO 50 or more applications as well as purchasing hardware and/or software used to support field employees who restore customer outages. Solutions include but are not limited to the following: Hardware - This budget often includes the purchasing of new hardware such as tablets, cell phones and MDTs when needed Software - Software upgrades and license renewal fees End of life servers and database purchases and upgrades Processes and workstreams also supported by these funds by way of small enhancements and IT consultation/support include: Work and Asset Management systems OMS Management systems Field mobility support devices Distributed Energy Resource management systems Data Analytics We have established a monthly release schedule for requested enhancements totaling about ten occurrences per year. The following will be included in these releases based on historical data: Upgrades to operating systems Replacement of end of life servers Migrating apps from end-of-life systems/platforms Production growth (extra memory, hard drive space,...) Minor enhancements to various DO IT supported apps Power BI development of reports and dashboards	The values realized is an improved customer and employee experience. These improvements will target our mobile applications used by DO field workers for status and complete customer restoration work completed by both employees and contractors. This investment is an ongoing effort important because our business partners regularly review and enhance their processes to benefit the customers, and ask us to accommodate for them programmatically.	It is critical that we capture business process changes in all associated systems to avoid manual workarounds which add operational overhead. There are no alternatives to supporting our business partners in their effort to improve systems that benefit DTE customers. It is critical that we capture business process changes in all associated systems to avoid manual workarounds which add operational overhead. Do nothing approach is not viable as it creates manual workrounds, elevates outage risk, and increases technical debt across DO applications.	Specialized workload - stay on premise	he use of cloud computing will be reviewed and approved by Technology and Architecture group where applicable	Yes	1/2/2027	12/31/2027	$ 3,388,575.82	$ 3,334,679.37	$ 786,194.89	$ 1,834,000.00	$ 125,840.00		$ 588,344.68	$ 53,496.25	$ 53,496.25					$ 53,496.25
197	2028	Distribution Operations Application Health	Sustainment	Electric	Plant and Field	Steve Ambrose	OPHD0003638	Level 3	This demand is a 3 year estimate for Distribution Operations Application Health sustainment work. The DO portfolio includes about 50 supported applications that may require some level of Information Technology enhancements throughout the year. Historically, there are various solutions needed based on the changing landscape of field operations. These enhancement dollars for DO are not meant to fund a single, known solution. The dollars have been historically used for significant enhancements to DO 50 or more applications as well as purchasing hardware and/or software used to support field employees who restore customer outages. Solutions include but are limited to the following: Hardware - This budget often includes the purchasing of new hardware such as tablets, cell phones and MDTs when needed Software - Software upgrades and license renewal fees End of life servers and database purchases and upgrades Processes and workstreams also supported by these funds by way of small enhancements and IT consultation/support include: Work and Asset Management systems OMS Management systems Field mobility support devices Distributed Energy Resource management systems Data Analytics We have established a monthly release schedule for requested enhancements totaling about ten occurrences per year. The following will be included in these releases based on historical data: Upgrades to operating systems Replacement of end of life servers Migrating apps from end-of-life systems/platforms Production growth (extra memory, hard drive space,...) Minor enhancements to various DO IT supported apps Power BI development of reports and dashboards	The values realized is an improved customer and employee experience. These improvements will target our mobile applications used by DO field workers for status and complete customer restoration work completed by both employees and contractors. This investment is an ongoing effort important because our business partners regularly review and enhance their processes to benefit the customers, and ask us to accommodate for them programmatically.	It is critical that we capture business process changes in all associated systems to avoid manual workarounds which add operational overhead. There are no alternatives to supporting our business partners in their effort to improve systems that benefit DTE customers. It is critical that we capture business process changes in all associated systems to avoid manual workarounds which add operational overhead. The do nothing alternative means requested changes that support customer restoration would not be implemented	Specialized workload - stay on premise	he use of cloud computing will be reviewed and approved by Technology and Architecture group where applicable	No	1/2/2028	12/31/2028	$ 3,350,021.19	$ 3,336,229.18	$ 874,215.48	$ 1,828,000.00		$ 654,505.70	$ 13,792.00	$ 9,792.00	$ 4,000.00				$ 13,792.00
198	2025	DTE Electric Generation Capacity Application Health	Sustainment	Electric	Plant and Field	Steve Ambrose	OPHD0001424	Actual	The recommended solution is to hard regularly scheduled releases to our Generation Supply Management System (GSMP). platform, which the Company uses to effectively calculate which generation plants it will offer into the MisoUnitnet Independent System Operator (MISO) market, which in turn contributes to the selection of plant capacity running per the MISO market schedule.	Complete IT support for all applications that support the buying, selling, and dispatching of power in the wholesale power market and the bulk electric system. Critical system applications are supported by IT personnel who understand the business, Strong Political and Regulatory Context - by ensuring support of applications that directly impact meeting compliance to FERC and NERC, and Superior and Sustainable Financial Performance by ensuring support of applications that directly impact power supply cost recovery (PSCR) savings initiatives.	No alternatives considered at this time as current solution platform meets the business needs. System is required to remain current to support up to date business. Doing nothing is not an option in supporting our system.	Not Applicable	This funding provides IT support for existing on-prem applications	Yes	1/1/2022	12/31/2025	$ 686,848.38	$ 686,666.32	$ 170,207.70	$ 370,550.98	$ 26,885.76	$ 1,400.00	$ 115,821.90	$ -	$ -	$ -				$ -
199	2026	DTE Electric Generation Capacity Application Health	Sustainment	Electric	Plant and Field	Steve Ambrose	OPHD0001571	Level 3																						

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200	2027	DTE Electric Generation Capacity Application Health	Sustainment	Electric	Plant and Field	Steve Ambrose	OPHD0001571	Level 3	The recommended solution is to hard regularly scheduled releases to our Generation Supply Management System (GSMP). platform, which the Company uses to effectively calculate which generation plants it will offer into the MisoUnitnet Independent System Operator (MISO) market, which in turn contributes to the selection of plant capacity running per the MISO market schedule. 2026: Implement 3 annual releases from vendor which implement new MISO market processes and rules, implement process changes for additions or modifications to DTE's generation fleet, and implement any prioritized business process changes, implement multi-asset registration, implement new business processes and system enhancements in addition to support new generation expansion. Perform efficiency upgrades to existing database. 2027: Implement 3 annual releases from vendor which implement new MISO market processes and rules, implement process changes for additions or modifications to DTE's generation fleet, and implement any prioritized business process changes.	Complete IT support for all applications that support the buying, selling, and dispatching of power in the wholesale power market and the bulk electric system. Critical system applications are supported by IT personnel who understand the business, Strong Political and Regulatory Context - by ensuring support of applications that directly impact meeting compliance to FERC and NERC, and Superior and Sustainable Financial Performance by ensuring support of applications that directly impact power supply cost recovery (PSCR) savings initiatives.	No alternatives considered at this time as current solution platform meets the business needs. System is required to remain current to support up to date business. Doing nothing is not an option in supporting our system.	Not Applicable	This funding provides IT support for existing on-prem applications	Yes	1/2/2026	12/31/2027	$ 617,989.38	$ 534,916.56	$ 314,476.71			$ 216,439.85	$ 82,993.43	$ 82,993.43					$ 82,993.43
201	2028	DTE Electric Generation Capacity Application Health	Sustainment	Electric	Plant and Field	Steve Ambrose	OPHD0001571	Level 3	The recommended solution is to hard regularly scheduled releases to our Generation Supply Management System (GSMP). platform, which the Company uses to effectively calculate which generation plants it will offer into the MisoUnitnet Independent System Operator (MISO) market, which in turn contributes to the selection of plant capacity running per the MISO market schedule. 2028: Implement 3 annual releases from vendor which implement new MISO market processes and rules, implement process changes for additions or modifications to DTE's generation fleet, and implement any prioritized business process changes.	Complete IT support for all applications that support the buying, selling, and dispatching of power in the wholesale power market and the bulk electric system. Critical system applications are supported by IT personnel who understand the business, Strong Political and Regulatory Context - by ensuring support of applications that directly impact meeting compliance to FERC and NERC, and Superior and Sustainable Financial Performance by ensuring support of applications that directly impact power supply cost recovery (PSCR) savings initiatives.	No alternatives considered at this time as current solution platform meets the business needs. System is required to remain current to support up to date business. Doing nothing is not an option in supporting our system.	Not Applicable	This funding provides IT support for existing on-prem applications	Yes	1/2/2028	12/31/2028	$ 690,000.00	$ 629,977.00	$ 369,266.50			$ 246,708.07	$ 60,000.00	$ 60,000.00					$ 60,000.00
202	2025	Enterprise Automation – Process Automation	Sustainment	Shared	Plant and Field	Steve Ambrose	OPHD0002977	Actual	- Re-looking is a breakdown of the scope of work that we are planning to complete in 2025. Blue Prism upgrade Our Blue Prism environment is one generation behind the latest released and supported generation. We aim to upgrade, from v8.x to v7.x, to realize the benefits of the latest performance and monitoring controls and coding capabilities of the software. Additionally, the latest versions of Blue Prism offer some level of artificial intelligence capability, to assist in spying and re-spying, up-or-change, interactive elements. Upgrading entails staging and changing all application environments (DEV thru PROD), re-basing all 100+ virtual machines which Blue Prism operates on, and re-testing, for accuracy and assurance, all 70+ process automations. - Power Platform applications modernizations Enterprise Automation sustains 30+ applications, some of which are coded utilizing canvas components. Although canvas components are able to serve a specific function or task within a respective application, the components are prone to depreciation / error in the event of upgrades. Model-driven components and applications, however, are generally more rigid and supported on an ongoing basis. In order to avoid asset depreciation (i.e., applications / components that are no longer functioning as intended or supported), applications and components will be updated, where possible and applicable, to model-driven. Model-driven components are released by Microsoft on an ongoing and ad-hoc basis, meaning that many model-driven components may simply not have been available at the time of the original application/ coding. As new components are released, it is necessary to update the coding for feature richness and sustainability. - Robotic Process Automations (RPAs) reengineering Several RPAs are experiencing higher-than-average levels of technical and / or business exceptions in the cases worked. Examples include CS016 , MT06, CT005 , MT02, CS003 - BCRED Late Billing Processes BCRED, CS003 - Refund Process, CS003 - AMI31/AMI21 Meter Change, and CS041 - HPP Payment Reallocations. These RPAs are primarily Customer Service-based, and work to resolve billing exceptions. Although the RPAs add a powerful capability to the business, they are not	The RPAs, combined, process over 1.2M transactions per year, across the Enterprise. The digital solutions are used by over 24 DTE employees / users on a daily basis. The digital solutions encompass 50K+ transactions per week.	N/A, as all solutions and products mentioned are existing and in production. This Demand encompasses the sustainment of said solutions, rather than evaluating different solutions or products for the same purpose.	Core energy management or cyber overcurly system - stay on premise	ncorporated into the DTE environment, and a part of DTE's overall cloud strategy. Blue Prism, is non-applicable, a	No	1/2/2025	12/31/2025	$ 494,502.28	$ 494,502.28	$ 36,062.54	$ 351,449.88	$ (991.47)		$ 107,000.33	$ -						$ -
203	2026	Enterprise Automation – Process Automation	Sustainment	Shared	Plant and Field	Steve Ambrose	OPHD0003623	Level 3	Blue Prism upgrade Our Blue Prism environment is one generation behind the latest released and supported generation. We aim to upgrade, from v7.x (early to v7.x (mid to late) or v8.x, to realize the benefits of the latest performance and monitoring controls and coding capabilities of the software. Additionally, the latest versions of Blue Prism offer some level of artificial intelligence capability, to assist in spying and re-spying, up-or-change, interactive elements. Upgrading entails staging and changing all application environments (DEV thru PROD), re-basing all 100+ virtual machines which Blue Prism operates on, and re-testing, for accuracy and assurance, all 70+ process automations. - Power Platform applications modernizations Enterprise Automation sustains 30+ applications, some of which are coded utilizing canvas components. Although canvas components are able to serve a specific function or task within a respective application, the components are prone to depreciation / error in the event of upgrades. Model-driven components and applications, however, are generally more rigid and supported on an ongoing basis. In order to avoid asset depreciation (i.e., applications / components that are no longer functioning as intended or supported), applications and components will be updated, where possible and applicable, to model-driven. Model-driven components are released by Microsoft on an ongoing and ad-hoc basis, meaning that many model-driven components may simply not have been available at the time of the original application/ coding. As new components are released, it is necessary to update the coding for feature richness and sustainability. - Robotic Process Automations (RPAs) reengineering Several RPAs are experiencing higher-than-average levels of technical and / or business exceptions in the cases worked. Examples include CS016 , MT06, CT005 , MT02, CS003 - BCRED Late Billing Processes BCRED, CS003 - Refund Process, CS003 - AMI31/AMI21 Meter Change, and CS041 - HPP Payment Reallocations. These RPAs are primarily Customer Service-based, and work to resolve billing exceptions. Although the RPAs add a powerful capability to the business, they are not	The RPAs, combined, process over 1.2M transactions per year, across the Enterprise. The digital solutions are used by over 24 DTE employees / users on a daily basis. The digital solutions encompass 50K+ transactions per week.	N/A, as all solutions and products mentioned are existing and in production. This Demand encompasses the sustainment of said solutions, rather than evaluating different solutions or products for the same purpose.	Core energy management or cyber overcurly system - stay on premise	ncorporated into the DTE environment, and a part of DTE's overall cloud strategy. Blue Prism, is non-applicable, a	No	1/2/2026	12/31/2026	$ 491,790.60	$ 491,790.60	$ 95,512.80	$ 320,000.00		$ 76,278.00	$ -						$ -
204	2027	Enterprise Automation – Process Automation	Sustainment	Shared	Plant and Field	Steve Ambrose	OPHD0003904	Level 3	Blue Prism upgrade Our Blue Prism environment is one generation behind the latest released and supported generation. We aim to upgrade, from v7.x (early to v7.x (mid to late) or v8.x, to realize the benefits of the latest performance and monitoring controls and coding capabilities of the software. Additionally, the latest versions of Blue Prism offer some level of artificial intelligence capability, to assist in spying and re-spying, up-or-change, interactive elements. Upgrading entails staging and changing all application environments (DEV thru PROD), re-basing all 100+ virtual machines which Blue Prism operates on, and re-testing, for accuracy and assurance, all 70+ process automations. - Power Platform applications modernizations Enterprise Automation sustains 30+ applications, some of which are coded utilizing canvas components. Although canvas components are able to serve a specific function or task within a respective application, the components are prone to depreciation / error in the event of upgrades. Model-driven components and applications, however, are generally more rigid and supported on an ongoing basis. In order to avoid asset depreciation (i.e., applications / components that are no longer functioning as intended or supported), applications and components will be updated, where possible and applicable, to model-driven. Model-driven components are released by Microsoft on an ongoing and ad-hoc basis, meaning that many model-driven components may simply not have been available at the time of the original application/ coding. As new components are released, it is necessary to update the coding for feature richness and sustainability. - Robotic Process Automations (RPAs) reengineering Several RPAs are experiencing higher-than-average levels of technical and / or business exceptions in the cases worked.	The RPAs, combined, process over 1.2M transactions per year, across the Enterprise. The digital solutions are used by over 24 DTE employees / users on a daily basis. The digital solutions encompass 50K+ transactions per week.	N/A, as all solutions and products mentioned are existing and in production. This Demand encompasses the sustainment of said solutions, rather than evaluating different solutions or products for the same purpose.	Core energy management or cyber overcurly system - stay on premise	ncorporated into the DTE environment, and a part of DTE's overall cloud strategy. Blue Prism, is non-applicable, a	No	1/2/2027	12/31/2027	$ 532,727.42	$ 532,727.42	$ 327,429.00			$ 205,302.42	$ -						$ -
205	2028	Enterprise Automation – Process Automation	Sustainment	Shared	Plant and Field	Steve Ambrose	OPHD0003566	Level 3	Blue Prism upgrade Our Blue Prism environment is one generation behind the latest released and supported generation. We aim to upgrade, from v7.x (early to v7.x (mid to late) or v8.x, to realize the benefits of the latest performance and monitoring controls and coding capabilities of the software. Additionally, the latest versions of Blue Prism offer some level of artificial intelligence capability, to assist in spying and re-spying, up-or-change, interactive elements. Upgrading entails staging and changing all application environments (DEV thru PROD), re-basing all 100+ virtual machines which Blue Prism operates on, and re-testing, for accuracy and assurance, all 70+ process automations. - Power Platform applications modernizations Enterprise Automation sustains 30+ applications, some of which are coded utilizing canvas components. Although canvas components are able to serve a specific function or task within a respective application, the components are prone to depreciation / error in the event of upgrades. Model-driven components and applications, however, are generally more rigid and supported on an ongoing basis. In order to avoid asset depreciation (i.e., applications / components that are no longer functioning as intended or supported), applications and components will be updated, where possible and applicable, to model-driven. Model-driven components are released by Microsoft on an ongoing and ad-hoc basis, meaning that many model-driven components may simply not have been available at the time of the original application/ coding. As new components are released, it is necessary to update the coding for feature richness and sustainability. - Robotic Process Automations (RPAs) reengineering Several RPAs are experiencing higher-than-average levels of technical and / or business exceptions in the cases worked. Examples include CS016 , MT06, CT005 , MT02, CS003 - BCRED Late Billing Processes BCRED, CS003 - Refund Process, CS003 - AMI31/AMI21 Meter Change, and CS041 - HPP Payment Reallocations. These RPAs are primarily Customer Service-based, and work to resolve billing exceptions. Although the RPAs add a powerful capability to the business, they are not	The RPAs, combined, process over 1.2M transactions per year, across the Enterprise. The digital solutions are used by over 24 DTE employees / users on a daily basis. The digital solutions encompass 50K+ transactions per week.	N/A, as all solutions and products mentioned are existing and in production. This Demand encompasses the sustainment of said solutions, rather than evaluating different solutions or products for the same purpose.	Core energy management or cyber overcurly system - stay on premise	ncorporated into the DTE environment, and a part of DTE's overall cloud strategy. Blue Prism, is non-applicable, a	Yes	1/2/2028	12/31/2028	$ 533,519.28	$ 533,519.28	$ 155,521.84	$ 327,200.00	$ 20,000.00		$ 82,797.44	$ -						$ -
206	2025	EDR Application Health	Sustainment	Shared	Plant and Field	Steve Ambrose	OPHD0001385	Actual	Increase the DDS Extracts that are currently available for DTE resources to allow access to DTE's location data in the DDS system. Increase IT resources that can focus on the installation of service packs, security updates, and support additional enhancements to be included in monthly releases into the DDS system. Implement additional interfaces to the DDS data integrations to field systems and DTE's operational data warehouse. Implement additional DDS assets to be integrated from and to work management systems.	Enhance the productivity of Distribution Operations by providing access to the status of additional equipment in the field.	Alternatives DDS vendors considered (such as Neuagio, Auto Desk, or Smallworld) were considered but not selected because the current DDS vendor has a long history in servicing our customers, and safety implications of not having the supporting documentation in place. For these reasons, and because the Company would also incur substantial costs to remove EDR-DDS and replace it with an alternate DDS solution, we did not select any alternate DDS vendors.	Not Applicable	continue to involve the ability to access DDS mapped services for reporting and will be positioned to provide AI or	Yes	1/2/2023	12/31/2025	$ 506,863.68	$ 475,737.68	$ 311,959.06	$ 294,858.68	$ 49,228.39		$ 69,685.63	$ 30,925.74	$ 12,904.12	$ 14,241.21	$ 3,555.76	$ 479.64		$ 23,864.64
207	2026	EDR Application Health	Sustainment	Shared	Plant and Field	Steve Ambrose	OPHD0001465	Level 3																						

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208	2027	ESRI Application Health	Sustainment	Shared	Plant and Field	Steve Ambrose	DHMDS003633	Level 3	To ensure the ESRI application remains operational and effective, we recommend ongoing investment in system enhancements, patches, and releases. This includes both minor and major software and hardware upgrades, as well as modifications to code or configuration to address significant issues within the GIS system. By continuously updating and improving the application, we can maintain its reliability and functionality, thereby supporting DTE's Electric and Gas business users and enhancing the accuracy of location data assets for employees and customers.	Operational Efficiency: Streamlined data sharing and workflow automation improve decision making and resource allocation. Reliability and Safety: Enhanced asset mapping and outage information lead to fewer outages and improved safety. Customers: Faster Response Times: Reduced downtime and quicker resolution of service issues. Enhanced Communication: Clearer and accurate information on service disruptions and maintenance. Employees: Empowered Field Operations: Mobile access to updated asset information improves efficiency. Simplified Workflows: Integration simplifies processes and enhances collaboration across departments.	A "do nothing" approach is not viable. Any alternative approach would disrupt our internal systems, impair our ability to serve customers, and negatively impact company safety.	Not Applicable	continue to involve the ability to access GIS mapped services for reporting and will be positioned to provide AI a	No	1/1/2027	12/31/2027	$ 504,616.53	$ 477,196.08	$ 120,965.20	$ 268,000.00				$ 88,250.86	$ 27,425.45	$ 27,425.45							$ 19,852.41
209	2028	ESRI Application Health	Sustainment	Shared	Plant and Field	Steve Ambrose	DHMDS003634	Level 3	Continuing maintenance for the ESRI application presents a critical opportunity to sustain reliable GIS capabilities across DTE Energy's Gas and Electric business units. Historically, the Electric and Gas organizations have submitted numerous independent requests for ESRI application enhancements, patches, and upgrades. Consolidating these efforts into a single, ongoing investment in system enhancements, patches, and releases—including minor and major software and hardware upgrades—is necessary to keep the platform operational, secure, and aligned with enterprise technology standards. This includes timely code and configuration changes to address defects, performance issues, and changing business requirements within the GIS environment. By proactively maintaining and improving the ESRI application, DTE ensures uninterrupted support for business users, maintains data accuracy for critical asset management decisions, and leverages previous ESRI investments for future technology investments while reducing operational risk and sustaining long-term business value.	Organization: Operational Efficiency: Streamlined data sharing and workflow automation improve decision making and resource allocation. Reliability and Safety: Enhanced asset mapping and outage information lead to fewer outages and improved safety. Customers: Faster Response Times: Reduced downtime and quicker resolution of service issues. Enhanced Communication: Clearer and accurate information on service disruptions and maintenance. Employees: Empowered Field Operations: Mobile access to updated asset information improves efficiency. Simplified Workflows: Integration simplifies processes and enhances collaboration across departments.	Alternative approach would cause disturbances to our internal system, ability to serve our customers and have a safety impact to the company	Not Applicable	continue to involve the ability to access GIS mapped services for reporting and will be positioned to provide AI a	No	1/1/2028	12/31/2028	$ 517,276.21	$ 486,096.33	$ 123,265.06	$ 273,000.00				$ 89,833.27	$ 31,281.88	$ 31,281.88							$ 22,648.08
210	2025	Everyday Daily Plan (EDDP) Application Health	Sustainment	Electric	Plant and Field	Steve Ambrose	DHMDS003822	Actual	Approved in U-21046																						
211	2026	Everyday Daily Plan (EDDP) Application Health	Sustainment	Electric	Plant and Field	Steve Ambrose	DHMDS003868	Level 3	Approved in U-21046																						
212	2027	Everyday Daily Plan (EDDP) Application Health	Sustainment	Electric	Plant and Field	Steve Ambrose	DHMDS003830	Level 3	Leverage the EDDP tool as the main solution for organizing promises for trouble work, configurable storm settings, and planned work priorities. Offer a consistent user experience regardless of storm or non-storm conditions, reducing learning curves and errors. This tool will: Prioritize Work Dynamically: Leverage existing dispatch priorities for trouble work, configurable storm settings, and planned work priorities. Streamline Crew Assignments: Automate geographic crew assignments to bundled work packages for increased efficiency. Integrate Systems for Visibility: Provide real-time data sharing and visibility across OMS, Crew Management, and other systems. Ensure Consistency: Offer a consistent user experience regardless of storm or non-storm conditions, reducing learning curves and errors. Enhance Efficiency and Response Times: Reduce manual processes like phone-based crew assignments and static Excel-based plans, enabling quicker restoration and improved resource allocation.	1. Organization: Operational Efficiency: Streamlined workflows, automated crew assignments, and optimized resource allocation. Reliability and Safety: Improved asset mapping and real-time outage data enhance safety and reduce service interruptions. 2. Customer: Faster Restoration: Reduced downtime with quicker resolution of service issues. Enhanced Communication: Clear, accurate updates during outages and maintenance. 3. Employee: Empowered Field Operations: Real-time mobile access to asset and work information improves productivity. Simplified Processes: Automation reduces manual tasks, enabling focus on critical work and collaboration.	Alternative approach would cause disturbances to our internal system, ability to serve our customers and have a safety impact to the company.	Standard market-based and/or commoditized non-core energy workload - deploy in commercial cloud	The application is using the cloud infrastructure and aligned with the direction of all storm critical applications.	No	1/1/2027	12/31/2027	$ 402,030.98	$ 229,153.88	$ 128,054.06	$ 16,000.00				$ 82,149.84	$ 172,877.13	$ 172,877.13							$ 172,877.13
213	2028	Everyday Daily Plan (EDDP) Application Health	Sustainment	Electric	Plant and Field	Steve Ambrose	DHMDS004230	Level 3	Leverage the EDDP tool as the main solution for organizing promises for trouble work, configurable storm settings, and planned work priorities. Offer a consistent user experience regardless of storm or non-storm conditions, reducing learning curves and errors. This tool will: Prioritize Work Dynamically: Leverage existing dispatch priorities for trouble work, configurable storm settings, and planned work priorities. Streamline Crew Assignments: Automate geographic crew assignments to bundled work packages for increased efficiency. Integrate Systems for Visibility: Provide real-time data sharing and visibility across OMS, Crew Management, and other systems. Ensure Consistency: Offer a consistent user experience regardless of storm or non-storm conditions, reducing learning curves and errors. Enhance Efficiency and Response Times: Reduce manual processes like phone-based crew assignments and static Excel-based plans, enabling quicker restoration and improved resource allocation.	1. Organization: Operational Efficiency: Streamlined workflows, automated crew assignments, and optimized resource allocation. Reliability and Safety: Improved asset mapping and real-time outage data enhance safety and reduce service interruptions. 2. Customer: Faster Restoration: Reduced downtime with quicker resolution of service issues. Enhanced Communication: Clear, accurate updates during outages and maintenance. 3. Employee: Empowered Field Operations: Real-time mobile access to asset and work information improves productivity. Simplified Processes: Automation reduces manual tasks, enabling focus on critical work and collaboration.	Alternative approach would cause disturbances to our internal system, ability to serve our customers and have a safety impact to the company.	Standard market-based and/or commoditized non-core energy workload - deploy in commercial cloud	The application is using the cloud infrastructure and aligned with the direction of all storm critical applications.	No	1/1/2028	12/31/2028	$ 419,279.56	$ 264,984.36	$ 117,981.76	$ 7,400.00				$ 98,073.20	$ 154,614.60	$ 154,614.60							$ 154,614.60
214	2025	Fuel Supply Application Health	Sustainment	Electric	Plant and Field	Steve Ambrose	DHMDS001427	Actual	Approved in U-21046																						
215	2026	Fuel Supply Application Health	Sustainment	Electric	Plant and Field	Steve Ambrose	DHMDS002171	Level 3	Approved in U-21046																						
216	2027	Fuel Supply Application Health	Sustainment	Electric	Plant and Field	Steve Ambrose	DHMDS002373	Level 3	It is recommended to keep Fuel Supply's business processes running efficiently and meet business operational needs by implementing monthly capability changes prioritized by the department. Ensure that all ARR production operating system and database software updates are configured and installed in order to ensure maximum application performance. This system will remain current through planned quarterly vendor releases which include new product capabilities and are required to remain current under vendor support. These changes generally require 1 FTE with significant Developer experience, year-round. 2026: Implement 3 annual PCI ETRM releases for new vendor provided functionality and to remain current on their platform, and implement business process changes needed related to Fuel Supply operations. Additionally, we intend to migrate from end of life Crystal Reports to a modern, supported reporting framework for the ARR application. 2027: Implement 3 annual PCI ETRM releases for new vendor provided functionality and to remain current on their platform, and implement business process changes needed related to Fuel Supply operations.	This business case will provide funding to keep Fuel Supply's business processes running efficiently and meet business operational needs effectively. All ARR production software updates are configured and installed in order to ensure maximum application performance. Minimize O&M Costs. To manage improvements to the ARR database based on changing business environment that directly impacts Corporate Fuel Supply (CFS) stakeholders including MISO, FirstEnergy plants, FirstEnergy Corp, and GenOps (e.g. fuel surcharge changes, new affiliates, etc.). These changes generally require 1 FTE with significant Developer experience, year-round.	No alternatives considered at this time as current solution platform meets the business needs. System is required to remain current to support up-to-date business processes. Alternate technology solutions include moving from existing custom solution to a vendor-provided and managed solution for which we are not seeking prioritization at this time our current forecast since it would not be a prudent use of resources. "Do nothing" is not an alternative because it would result in an unnecessary and unjustifiably high administrative burden on the Company, with associated increases in O&M expense due to the increased staff that would be required to manually mitigate the gaps left behind. To the extent we had not undertaken the automation efforts, we would have lost expertise from retiring resources who were primarily responsible for this data entry.	Not Applicable	of which are cloud-based computing, some are on-prem. Each solution that exceeds $100K and funded under Su	No	1/1/2026	12/31/2027	$ 429,758.61	$ 398,796.05	$ 251,390.73					$ 147,405.32	$ 30,822.36	$ 30,122.36	$ 800.00						$ 30,822.36
217	2028	Fuel Supply Application Health	Sustainment	Electric	Plant and Field	Steve Ambrose	DHMDS002516	Level 3	It is recommended to keep Fuel Supply's business processes running efficiently and meet business operational needs by implementing monthly capability changes prioritized by the department. Ensure that all ARR production operating system and database software updates are configured and installed in order to ensure maximum application performance. This system will remain current through planned quarterly vendor releases which include new product capabilities and are required to remain current under vendor support. These changes generally require 1 FTE with significant Developer experience, year-round. 2026: Implement 3 annual PCI ETRM releases for new vendor provided functionality and to remain current on their platform, and implement business process changes needed related to Fuel Supply operations.	This business case will provide funding to keep Fuel Supply's business processes running efficiently and meet business operational needs effectively. All ARR production software updates are configured and installed in order to ensure maximum application performance. Minimize O&M Costs. To manage improvements to the ARR database based on changing business environment that directly impacts Corporate Fuel Supply (CFS) stakeholders including MISO, FirstEnergy plants, FirstEnergy Corp, and GenOps (e.g. fuel surcharge changes, new affiliates, etc.). These changes generally require 1 FTE with significant Developer experience, year-round.	No alternatives considered at this time as current solution platform meets the business needs. System is required to remain current to support up-to-date business processes. Alternate technology solutions include moving from existing custom solution to a vendor-provided and managed solution for which we are not seeking prioritization at this time our current forecast since it would not be a prudent use of resources. "Do nothing" is not an alternative because it would result in an unnecessary and unjustifiably high administrative burden on the Company, with associated increases in O&M expense due to the increased staff that would be required to manually mitigate the gaps left behind. To the extent we had not undertaken the automation efforts, we would have lost expertise from retiring resources who were primarily responsible for this data entry.	Not Applicable	of which are cloud-based computing, some are on-prem. Each solution that exceeds $100K and funded under Su	No	1/1/2028	12/31/2028	$ 483,819.19	$ 449,933.69	$ 276,617.17					$ 173,916.52	$ 33,985.50	$ 33,985.50							$ 33,985.50
218	2027	IFS Mobile Workforce Management (MWM) Application Health	Sustainment	Shared	Plant and Field	Steve Ambrose	DHMDS003835	Level 3	Support activities encompass both minor and major software upgrades, as well as targeted code or configuration changes to address defects, performance issues, and changing business requirements within the GIS environment. These activities manage day-to-day system maintenance, configuration updates, and integration support. The vendor provides specialized assistance for complex upgrades, platform enhancements, and resolution of escalated issues that require proprietary expertise. This collaborative model allows us to maintain a stable and secure field service environment while leveraging vendor capabilities for high-impact technical interventions and long-term system evolution. The application underwent thorough evaluation during its initial implementation. At the start of each year, the system is reassessed for sustainability, vulnerability, and vendor product development strategy. The transition from Salesforce Click (SC) to IFS is planned for FY 2026. The proposed solution includes maintenance tasks to address critical vulnerabilities and business-driven enhancements. These will be integrated into regular support activities, ensuring continuous improvements to enhance efficiencies in our business unit processes."	Organization: Improved Operational Efficiency: Optimize resource allocation, leading to overall operational efficiency gains. Reduced Costs: Streamlining processes and optimizing resource utilization can lead to cost savings for the organization, such as reduced overtime expenses and improved resource efficiency. Customer: Faster Response Times: Minimizing downtime and expediting the impact of disruptions on their operations in daily lives. Improved Communication: Clear and timely communication and accurate information. Employee: Streamlined Workflow: The enhancement simplifies and streamlines the dispatching and scheduling processes for field personnel, reducing administrative burdens and enabling them to focus on their core responsibilities. Improved Safety: Faster response times and better coordination of crews contribute to a safer working environment for employees, reducing the risk of accidents or injuries	A "do nothing" approach is not viable. Any alternative would disrupt our internal systems, impair our ability to serve customers, and negatively impact company safety. Database performance tuning is considered as a way to enhance system performance, ensuring the platform operates optimally. Since IFS Mobile Workforce Management (MWM) was implemented in Q1 2020 as our enterprise field service solution, continued investment and maintenance are critical. A "do nothing" approach is not an option, as it would compromise system reliability, security, and customer satisfaction. Alternatives—such as transitioning to a new platform—would introduce significant risks to reliability and business performance	Standard market-based and/or commoditized non-core energy workload - deploy in commercial cloud	Click-soft is a cloud-based computing system hosted in Microsoft Azure Cloud	No	1/1/2027	12/31/2027	$ 1,106,079.65	$ 782,376.93	$ 207,827.45	$ 286,800.00				$ 197,643.51	$ 412,708.04	$ 2,768.84	$ 410,000.00						$ 398,801.27
219	2028	IFS Mobile Workforce Management (MWM) Application Health	Sustainment	Shared	Plant and Field	Steve Ambrose	DHMDS003836	Level 3	Sustaining the IFS Mobile Workforce Management (MWM) application is essential to ensuring uninterrupted and efficient field service operations for DTE's Motor Reading, RMF, and Gas business units. IFS MWM is the enterprise workforce management platform that replaced ClickSoftware in 2020 and now serves as the system of record for scheduling, dispatch, and execution of field work. Ongoing investment is required to maintain system integrity, performance, and alignment with business operations that depend on real-time, reliable workforce coordination. Without sustained support, the platform risks falling behind current business needs, which could lead to increased manual workarounds, reduced field service efficiency, and operational inefficiencies across critical field functions.Sustainment activities include regular software upgrades, defect remediation, and targeted configuration changes to ensure continued reliability and responsiveness as business needs evolve. These efforts help prevent outages, support regulatory and security compliance, and enable continued optimization of field workflows.	Organization Improved Operational Efficiency: Optimizes resource allocation, driving efficiency gains. Cost Reduction: Streamlined processes and better resource utilization can reduce overtime and operational costs. Customer Faster Response Times: Minimizes downtime and disruption during critical events. Improved Communication: Provides clear, timely updates and accurate information. Employee Streamlined Workflow: Simplifies dispatching and scheduling, reducing administrative burden. Enhanced Safety: Faster response and better crew coordination create a safer work environment.	Since IFS Mobile Workforce Management (MWM) was implemented in Q1 2020 as our enterprise field service solution, continued investment and maintenance are critical. A "do nothing" approach is not an option, as it would compromise system reliability, security, and customer satisfaction. Alternatives—such as transitioning to a new platform—would introduce significant risks.	Standard market-based and/or commoditized non-core energy workload - deploy in commercial cloud	IFS Mobile Workforce Management (MWM) is a Cloud-based computing system hosted in Azure	No	1/1/2028	12/31/2028	$ 1,232,526.66	$ 809,090.26	$ 292,219.00	$ 317,200.00				$ 199,671.26	$ 427,436.46	$ 7,436.46	$ 420,000.00						$ 399,463.00
220	2025	ITS ACMS Application Health	Sustainment	Electric	Plant and Field	Steve Ambrose	DHMDS002490	Actual	The ITS ACMS Application Health project involves ongoing investment in the Advanced Distribution Management System (ADMS) and related IT assets, including server upgrades, hardware enhancements, software updates, and application maintenance. This project supports reliable distribution and sub-transmission activities and enhances the critical outage management system. Further, this will benefit the organization by ensuring compliance with regulatory requirements, reducing the risk of System failures and downtime, and improving overall operational efficiency. Customers will benefit from more reliable service, while employees will have the tools and systems needed to effectively manage distribution operations. This includes capital investment in servers, hardware components, applications, application enhancement/upgrades, table changes, table updates, screen changes, new reports, routine logic changes, coding for data retrieval, enhancements based on business process, and data updates. Additional expense includes licensing maintenance. This demand provides a finite resource pool to perform upgrades and manage the application health including requested monthly changes as required by the business.	This investment will contribute to continued safe and reliable distribution and sub-transmission activities, as well as support and enhancement for our critical outage management system. Further, this will benefit the organization by ensuring compliance with regulatory requirements, reducing the risk of System failures and downtime, and improving overall operational efficiency. Customers will benefit from more reliable service, while employees will have the tools and systems needed to effectively manage distribution operations.	No alternatives were considered as the ongoing investment in the ADMS application portfolio is necessary to ensure compliance with regulatory requirements and to ensure the safe and reliable operation of the electrical grid. The Company rejected the use of alternate technological solutions as this would require a complete overhead of existing, established, critical platforms with no compensatory benefit, after significant investment. Similarly, a "do nothing" alternative was rejected as this would result in grid destabilization, problems with power generation (DPG), and an inability to manage outages in our system.	Not Applicable	ng strategy as this project focuses on the ongoing investment in support of existing IT assets and applications, an	Yes	1/1/2024	12/31/2027	$ 1,746,911.98	$ 1,284,121.85	$ 376,272.67	$ 627,826.38	$ 35,021.10	$ 3,400.18		$ 247,391.87	$ 461,389.08	$ 423,948.40	$ (161.95)	$ 1,242.65	$ 36,316.30				$ 461,389.08
221	2026	ITS ACMS Application Health	Sustainment	Electric	Plant and Field	Steve Ambrose	DHMDS002490	Level 3	The ITS ACMS Application Health project involves ongoing investment in the Advanced Distribution Management System (ADMS) and related IT assets, including server upgrades, hardware enhancements, software updates, and application maintenance. This project supports reliable distribution and sub-transmission activities and enhances the critical outage management system. Further, this will benefit the organization by ensuring compliance with regulatory requirements, reducing the risk of System failures and downtime, and improving overall operational efficiency. Customers will benefit from more reliable service, while employees will have the tools and systems needed to effectively manage distribution operations. The recommended solution is to continue providing ongoing investment into the ADMS application portfolio and related IT assets for the work outlined in the section above. This includes capital investment in servers, hardware components, applications, application enhancement/upgrades, table changes, table updates, screen changes, new reports, routine logic changes, coding for data retrieval, enhancements based on business process, and data updates. Additional expense includes licensing maintenance. This demand provides a finite resource pool to perform upgrades and manage the application health including requested monthly changes as required by the business.	This investment will contribute to continued safe and reliable distribution and sub-transmission activities, as well as support and enhancement for our critical outage management system. Further, this will benefit the organization by ensuring compliance with regulatory requirements, reducing the risk of System failures and downtime, and improving overall operational efficiency. Customers will benefit from more reliable service, while employees will have the tools and systems needed to effectively manage distribution operations.	No alternatives were considered as the ongoing investment in the ADMS application portfolio is necessary to ensure compliance with regulatory requirements and to ensure the safe and reliable operation of the electrical grid. The Company rejected the use of alternate technological solutions as this would require a complete overhead of existing, established, critical platforms with no compensatory benefit, after significant investment. Similarly, a "do nothing" alternative was rejected as this would result in grid destabilization, problems with power generation (DPG), and an inability to manage outages in our system.	Not Applicable	ng strategy as this project focuses on the ongoing investment in support of existing IT assets and applications, an	No	1/1/2025	12/31/2027	$ 2,202,266.17	$ 1,863,027.88	$ 233,918.56	$ 1,425,099.92				$ 264,309.36	$ 489,258.61	$ 117,258.51	$ 372,000.00						$ 489,258.61
222	2027	ITS ACMS Application Health	Sustainment	Electric	Plant and Field	Steve Ambrose	DHMDS002490	Level 3	The ITS ACMS Application Health project involves ongoing investment in the Advanced Distribution Management System (ADMS) and related IT assets, including server upgrades, hardware enhancements, software updates, and application maintenance. This project supports reliable distribution and sub-transmission activities and enhances the critical outage management system. Further, this will benefit the organization by ensuring compliance with regulatory requirements, reducing the risk of System failures and downtime. Customers benefit from improved service reliability, while employees gain effective tools for managing distribution operations. The recommended solution is to continue providing ongoing investment into the ADMS application portfolio and related IT assets for the work outlined in the section above. This includes capital investment in servers, hardware components, applications, application enhancement/upgrades, table changes, table updates, screen changes, new reports, routine logic changes, coding for data retrieval, enhancements based on business process, and data updates. Additional expense includes licensing maintenance. This demand provides a finite resource pool to perform upgrades and manage the application health including requested monthly changes as required by the business.	This investment will contribute to continued safe and reliable distribution and sub-transmission activities, as well as support and enhancement for our critical outage management system. Further, this will benefit the organization by ensuring compliance with regulatory requirements, reducing the risk of System failures and downtime, and improving overall operational efficiency. Customers will benefit from more reliable service, while employees will have the tools and systems needed to effectively manage distribution operations.	No alternatives were considered as the ongoing investment in the ADMS application portfolio is necessary to ensure compliance with regulatory requirements and to ensure the safe and reliable operation of the electrical grid. The Company rejected the use of alternate technological solutions as this would require a complete overhead of existing, established, critical platforms with no compensatory benefit, after significant investment. Similarly, a "do nothing" alternative was rejected as this would result in grid destabilization, problems with power generation (DPG), and an inability to manage outages in our system.	Not Applicable	ng strategy as this project focuses on the ongoing investment in support of existing IT assets and applications, an	No	1/1/2026	12/31/2027	$ 2,344,895.76	$ 1,857,491.88	$ 230,462.34	$ 1,422,900.00				$ 264,309.27	$ 487,494.67	$ 117,494.67	$ 370,000.00						$ 487,494.67
223	2028	ITS ACMS Application Health	Sustainment	Electric	Plant and Field	Steve Ambrose	DHMDS002587	Level 3	Capital investment is needed within this extensive suite of applications for the aforementioned support, upgrades, and enhancements to ahore ag aging infrastructure and meet the increasing demands for digitalization within ongoing business requirements to operate the grid. Additional funding is needed for licensing, operation, and support of the critical ADMS application portfolio. The recommended solution is to continue providing ongoing investment into the ADMS application portfolio and related IT assets for the work outlined in the section above. This includes capital investment in servers, hardware components, applications, application enhancement/upgrades, table changes, table updates, screen changes, new reports, routine logic changes, coding for data retrieval, enhancements based on business process, and data updates. Additional expense includes licensing maintenance. This demand provides a finite resource pool to perform upgrades and manage the application health including requested monthly changes as required by the business.	This investment will contribute to continued safe and reliable distribution and sub-transmission activities, as well as support and enhancement for our critical outage management system. Further, this will benefit the organization by ensuring compliance with regulatory requirements, reducing the risk of System failures and downtime, and improving overall operational efficiency. Customers will benefit from more reliable service, while employees will have the tools and systems needed to effectively manage distribution operations.	No alternatives were considered as the ongoing investment in the ADMS application portfolio is necessary to ensure compliance with regulatory requirements and to ensure the safe and reliable operation of the electrical grid. The Company rejected the use of alternate technological solutions as this would require a complete overhead of existing, established, critical platforms with no compensatory benefit, after significant investment. Similarly, a "do nothing" alternative was rejected as this would result in grid destabilization, problems with power generation (DPG), and an inability to manage outages in our system.	Not Applicable	ng strategy as this project focuses on the ongoing investment in support of existing IT assets and applications, an	No	1/1/2028	12/31/2028	$ 2,210,207.68	$ 1,897,476.63	$ 464,771.76	$ 974,300.00				$ 348,704.29	$ 502,731.85	$ 102,731.85	$ 350,000.00						$ 502,731.85
224	2025	ITS GIS Application Health	Sustainment	Electric	Plant and Field	Steve Ambrose	DHMDS002489	Actual	To ensure high availability and optimal performance, the system requires capital investment for regular upgrades and enhancements to the software products, servers, infrastructure and workstations as well as accompanying expense for patching, compliance efforts, and maintenance to ensure that these systems are running at their best and can handle the demands placed on them. This demand provides a finite resource pool to perform upgrades and manage the application health including requested monthly changes as required by the business.	With this investment, DTE can ensure the safe and reliable operation of the electrical grid and maintain NERC CIP compliance of the infrastructure. This helps to avoid potential penalties, fines, and legal liabilities while maintaining the company's reputation as a reliable energy provider. The customers benefit from the ongoing support and maintenance of the Energy management System, Generation Management System, Outage Management System, and Switch Order Management systems. These systems help to ensure uninterrupted electrical service, minimize downtime, and speed up the restoration process during outages. Overall, maintaining the IT GIS application benefits the organization, customers, and employees by ensuring the safe and reliable operation of the electrical grid, maintaining compliance, and providing uninterrupted electrical service. 2024 upgrades/enhancements: Upgrades/enhancements required for compliance (ad hoc) ADMS upgrade/enhancements (to be norm in 2024) Underground upgrades (ad hoc)	The Company rejected the use of alternate technological solutions as this would require a complete overhead of existing, established, critical platforms with no compensatory benefit, after significant investment. Similarly, a "do nothing" alternative was rejected as this would result in grid destabilization, problems with power generation (DPG), and an inability to manage outages in our system.	Not Applicable	chnology strategy as this project focuses on the ongoing function of existing IT assets and applications, and not t	Yes	1/1/2024	12/31/2025	$ 982,929.00	$ 982,928.98	$ 418,425.68	$ 273,627.98	$ 1,850.54	$ 1,988.78		$ 297,222.69	$ -	$ -	$ -						$ -
225	2026	Maximo Application Health	Sustainment	Shared	Plant and Field	Steve Ambrose	DHMDS002447	Level 3	The continuation of Maximo as the enterprise work and asset management platform. The recommended solution for improving database health involves initiating a proof-of-concept for archiving Maximo data and deploying the solution if it meets business requirements. Also, database health includes upgrading the databases. The project team will address issues with Maximo's performance and stability by implementing database optimizations, such as indexing and query enhancements, and all environments. Evaluate and deploy an automated testing solution to improve software quality. Update to a supported software versioning system to maintain software code. Assess securing Maximo privilege identities by utilizing the enterprise privilege access management solution and implement if technically feasible.	The benefit value for this demand allows us to achieve the following: Customer Satisfaction: Reliable and functional EAM applications ensure seamless service delivery, improving trust and loyalty. Customers experience consistent performance and fewer disruptions in service. Business Partner Confidence: An operable and efficient system ensures transparency and smooth collaboration, fostering stronger partnerships and mutual growth. Employee Satisfaction: Providing IT support teams with effective tools and resources enhances their efficiency, reduces frustration, and creates a more fulfilling work environment. Improved workflows and reduced manual tasks free up employees to focus on strategic activities, fostering professional growth and engagement. Together, these benefits strengthen an organization's ability to achieve enterprise asset management priorities while balancing the needs of its stakeholders.	A "do-nothing" approach is eliminated as an option since administrative and maintenance tasks are crucial for platform functionality. While continuing with manual text scripts was considered, automation could potentially offer improved efficiency and reliability. The impact of staying on an unsupported system was evaluated, likely focusing on risks like security vulnerabilities and lack of updates. Assessed the risk of syncing the inspection forms and the reliance on manual processes to maintain secure privileged access, which could lead to inefficiencies and potential errors. Database performance tuning is considered as a way to enhance system performance, ensuring the platform operates optimally.	Not Applicable	Solution is supported on-premise	No	1/1/2026	12/31/2026	$ 2,970,026.12	$ 1,240,035.87	$ 360,151.06	$ 564,750.00				$ 314,964.67	$ 1,758,000.25	$ 1,719,500.25	$ 15,500.00						$ 1,252,520.10
226	2027	Maximo Application Health	Sustainment	Shared	Plant and Field	Steve Ambrose	DHMDS003864	Level 3	Database Health: Conduct a proof-of-concept for archiving Maximo data and proceed with deployment if it aligns with business requirements. Upgrade the databases to ensure optimal performance and future-proofing. Inspection Forms: Address migration challenges across the production support database Ensure consistent inspection forms across all environments. Software Quality: Implement an automated testing solution to boost the quality and reliability of software. Software Versioning: Transition to a supported software versioning system for effective software code maintenance. Access Management: Evaluate securing Maximo privileged identities by leveraging the enterprise privilege access management solution. Implement this solution if it proves to be technically feasible.	The benefit value for this demand allows us to achieve the following: Customer Satisfaction: Reliable and functional EAM applications ensure seamless service delivery, improving trust and loyalty. Customers experience consistent performance and fewer disruptions in service. Business Partner Confidence: An operable and efficient system ensures transparency and smooth collaboration, fostering stronger partnerships and mutual growth. Employee Satisfaction: Providing IT support teams with effective tools and resources enhances their efficiency, reduces frustration, and creates a more fulfilling work environment. Improved workflows and reduced manual tasks free up employees to focus on strategic activities, fostering professional growth and engagement. Together, these benefits strengthen an organization's ability to achieve enterprise asset management priorities while balancing the needs of its stakeholders.	A "do-nothing" approach is eliminated as an option since administrative and maintenance tasks are crucial for platform functionality. While continuing with manual text scripts was considered, automation could potentially offer improved efficiency and reliability. The impact of staying on an unsupported system was evaluated, likely focusing on risks like security vulnerabilities and lack of updates. Assessed the risk of syncing the inspection forms and the reliance on manual processes to maintain secure privileged access, which could lead to inefficiencies and potential errors. Database performance tuning is considered as a way to enhance system performance, ensuring the platform operates optimally.	Not Applicable	Solution is supported on-premise	No	1/4/2027	12/31/2027	$ 2,132,981.19	$ 1,240,825.58	$ 331,536.28	$ 1,010,000.00				$ 120,097.30	$ 892,355.60	$ 2,355.60	$ 890,000.00						$ 648,065.45

227	2028	Plasmo Application Health	Sustainment	Shared	Plant and Field	Steve Ambrose	DHMD0004271	Level 3	Database Health: Conduct a proof-of-concept for archiving Plasmo data and proceed with deployment if it aligns with business requirements. Upgrade the database to ensure optimal performance and future-proofing. Inspection Forms: Address migration challenges across the production support database Ensure consistent inspection forms across all environments. Software Quality: Implement an automated testing solution to boost the quality and reliability of software. Software Versioning: Transition to a supported software versioning system for effective software code maintenance. Access Management: Evaluate securing Plasmo principal identities by leveraging the enterprise privilege access management solution. Implement this solution if it proves to be technically feasible.	The benefit value for this demand allows us to achieve the following: Customer Satisfaction: Reliable and functional EAM applications ensure seamless service delivery, improving trust and loyalty. Customers experience consistent performance and fewer disruptions in service. Business Partner Confidence: An operable and efficient system ensures transparency and smooth collaboration, fostering stronger partnerships and mutual growth. Employee Satisfaction: Providing IT support teams with effective tools and resources enhances their efficiency, reduces frustration, and creates a more fulfilling work environment. Improved workflows and reduced manual tasks free up employees to focus on strategic activities, fostering professional growth and engagement. Together, these benefits strengthen an organization's ability to achieve enterprise asset management priorities while balancing the needs of its stakeholders.	A 'do-nothing' approach is estimated as an option since administrative and maintenance tasks are currently handled by existing resources. While manual tasks or scripts were considered, automation could potentially offer improved efficiency and reliability. The impact of staying on an unsupported system was assessed, highlighting risks to system stability and security if no action is taken. Assessed the risk of not syncing the inspection forms and the reliance on manual processes to maintain secure privileged access, which could lead to inefficiencies and potential errors. Database performance tuning is considered as a way to enhance system performance, ensuring the platform operates optimally.	Not Applicable	Solution is supported on-premise	No	1/1/2028	12/31/2028	$ 2,308,525.45	$ 1,241,947.45	$ 24,448.00	$ 640,000.00		$ 500,000.00	$ 77,481.45	$ 1,696,576.00	$ 77,576.00	$ 1,619,000.00					$ 1,228,325.00
228	2025	Network Reliability and Monitoring	Sustainment	Electric	Plant and Field	Steve Ambrose	DHMD0003391	Actual	The Network Reliability and Monitoring will track the life cycle of telecommunications equipment, report and analyze the performance and the impact on the electrical system. This will enable and provide visibility into telecommunications real time performance, asset management, and ability to perform analytics on telecommunications equipment for improving equipment reliability	Organization: Efficiency: Streamlines asset management and maintenance, saving costs. Reliability: Minimizes downtime, upholding the organization's reputation. Risk Management: Proactively identifies and addresses network issues, reducing operational risks. Customer: Service Quality: Ensures consistent service delivery, improving customer satisfaction. Reliability: Provides dependable service, increasing customer trust. Issue Resolution: Swiftly resolves network problems, minimizing disruptions for customers. Employee: Process Streamlining: Reduces manual tasks, allowing employees to focus on higher-value work. Productivity: Enhances efficiency, enabling employees to meet tasks more effectively. Development Opportunities: Provides training and skill-building, fostering professional growth and satisfaction.	No Alternatives are considered at this time.	Not Applicable	NA	Yes	1/1/2025	12/31/2025	$ 985,798.68	$ 985,798.73	$ 366,900.00	$ (442,159.68)	$ 10,063.00	$ 388,555.68	$ 179,522.78	$ -	$ -					$ -
229	2025	Nuclear Generation Business Systems Replacement	Sustainment	Electric	Plant and Field	Steve Ambrose	DHMD0001447	Actual	Approved in U-21460																					
230	2026	Nuclear Generation Business Systems Replacement	Sustainment	Electric	Plant and Field	Steve Ambrose	DHMD0001286	Level 3	Approved in U-21460																					
231	2027	Nuclear Generation Business Systems Replacement	Sustainment	Electric	Plant and Field	Steve Ambrose	DHMD0003507	Level 3	The recommended solution is to execute a planned 2027 remediation and modernization program for Nuclear Generation's key and critical business applications. This program provides a structured, risk-based approach to maintain regulatory compliance, reduce cybersecurity exposure, and sustain operational reliability by proactively addressing technology obsolescence and security vulnerabilities. For 2027, the solution includes the following targeted remediation activities, executed as needed based on risk, regulatory requirements, and vendor support status: • Implement Electronic Signature capabilities to streamline and ensure efficiency requirements • Upgrade eQOMS to the Lumada platform to maintain vendor support, security posture, and operational functionality • Replace obsolete servers as required to eliminate unsupported infrastructure • Decommission obsolete databases as required to address end of support and security vulnerabilities • Perform nuclear application version upgrades as required to maintain compliance and functionality • Execute memory, storage, and processor upgrades as required to ensure performance, reliability, and vendor support This approach enables Nuclear Generation to remediate three to six key or critical applications annually, preventing the accumulation of unsupported technologies and reducing the likelihood of unplanned outages, regulatory findings, or cybersecurity incidents. The investment supports the continued operation, security, and compliance of Nuclear Generation's existing portfolio of key and critical applications, including—but not limited to—systems that support radiation protection, work and outage management, engineering safety calculations, corrective action programs, security access control, document and records management, training and qualification management, fatigue rule compliance, emergency response, and nuclear asset management. By funding this recurring remediation strategy, Nuclear Generation establishes a repeatable and sustainable mechanism to: • Maintain vendor-supported platforms • Mitigate cybersecurity and obsolescence risk exposure • Improve system reliability and performance • Avoid reactive, higher cost emergency replacements This solution ensures that Nuclear Generation's critical application environment remains secure, compliant, and operationally resilient while supporting ongoing regulatory and business requirements.	This investment directly supports DTE's strategic goals of safe, reliable, and compliant operations by maintaining Nuclear Generation's key and critical applications in a vendor-supported and secure state. Proactive remediation reduces regulatory non-compliance risk, strengthens cybersecurity posture, and improves inspection and audit readiness, helping avoid unplanned outages, enforcement actions, or reactive remediation costs. These outcomes align with DTE's focus on risk management, operational resilience, and long-term asset stewardship. By sustaining systems that support nuclear licensing, regulatory reporting, and emergency response, this investment reinforces DTE's commitment to public safety, regulatory trust, and reliable energy generation. Maintaining compliant and highly available nuclear systems supports safe plant operation, transparent regulatory engagement, and continued confidence from oversight agencies and the communities DTE serves. Employee (Operations, Engineering, Regulatory, and Support Staff): Modernized and reliable applications enable employees to execute safety-critical and compliance-driven work more efficiently and accurately. Reduced system instability and fewer manual workarounds support safer working conditions, improved productivity, and better use of skilled resources—aligning with DTE's strategic goal of empowering employees with reliable tools to perform critical work safely and effectively.	Do Nothing would add unnecessary compliance complexity, the opportunity for increased human errors, inefficient use of resources and increased operational risks due to security vulnerabilities and outdated and unsupported, obsolete hardware / software applications.	Core energy management or cyber oserurity system - stay on premise	Yes	1/1/2027	12/31/2027	$ 750,088.33	$ 698,000.33	$ 386,501.30		$ 25,569.00	$ 36,570.00	$ 246,429.01	$ 52,000.00	$ 52,000.00					$ 52,000.00
232	2028	Nuclear Generation Business Systems Replacement	Sustainment	Electric	Plant and Field	Steve Ambrose	DHMD0004211	Level 3	The recommended solution is to execute a planned 2028 remediation and modernization program for Nuclear Generation's key and critical business applications. This program provides a structured, risk-based approach to maintain regulatory compliance, reduce cybersecurity exposure, and sustain operational reliability by proactively addressing technology obsolescence and security vulnerabilities. For 2028, the solution includes the following targeted remediation activities, executed as needed based on risk, regulatory requirements, and vendor support status: • Final Upgrade eQOMS to the Lumada platform to maintain vendor support, security posture, and operational functionality • Replace obsolete servers as required to eliminate unsupported infrastructure • Replace obsolete databases as required to address end of support and security vulnerabilities • Perform nuclear application version upgrades as required to maintain compliance and functionality • Execute memory, storage, and processor upgrades as required to ensure performance, reliability, and vendor support This approach enables Nuclear Generation to remediate three to six key or critical applications annually, preventing the accumulation of unsupported technologies and reducing the likelihood of unplanned outages, regulatory findings, or cybersecurity incidents. The investment supports the continued operation, security, and compliance of Nuclear Generation's existing portfolio of key and critical applications, including—but not limited to—systems that support radiation protection, work and outage management, engineering safety calculations, corrective action programs, security access control, document and records management, training and qualification management, fatigue rule compliance, emergency response, and nuclear asset management. By funding this recurring remediation strategy, Nuclear Generation establishes a repeatable and sustainable mechanism to: • Maintain vendor-supported platforms • Mitigate cybersecurity and obsolescence risk exposure	This investment directly supports DTE's strategic goals of safe, reliable, and compliant operations by maintaining Nuclear Generation's key and critical applications in a vendor-supported and secure state. Proactive remediation reduces regulatory non-compliance risk, strengthens cybersecurity posture, and improves inspection and audit readiness, helping avoid unplanned outages, enforcement actions, or reactive remediation costs. These outcomes align with DTE's focus on risk management, operational resilience, and long-term asset stewardship. By sustaining systems that support nuclear licensing, regulatory reporting, and emergency response, this investment reinforces DTE's commitment to public safety, regulatory trust, and reliable energy generation. Maintaining compliant and highly available nuclear systems supports safe plant operation, transparent regulatory engagement, and continued confidence from oversight agencies and the communities DTE serves. Employee (Operations, Engineering, Regulatory, and Support Staff): Modernized and reliable applications enable employees to execute safety-critical and compliance-driven work more efficiently and accurately. Reduced system instability and fewer manual workarounds support safer working conditions, improved productivity, and better use of skilled resources—aligning with DTE's strategic goal of empowering employees with reliable tools to perform critical work safely and effectively.	Do Nothing would add unnecessary compliance complexity, the opportunity for increased human errors, inefficient use of resources and increased operational risks due to security vulnerabilities and outdated and unsupported, obsolete hardware / software applications.	Core energy management or cyber oserurity system - stay on premise	Yes	1/2/2028	12/31/2028	$ 750,058.49	$ 698,001.84	$ 387,125.57		$ 25,569.00	$ 36,740.00	$ 248,636.27	$ 52,058.65	$ 52,058.65					$ 52,058.65
233	2025	Production Growth	Sustainment	Shared	Plant and Field	Steve Ambrose	DHMD001400	Actual	Project will be processed by sub-Air Time computing power, storage capacity, database availability, and middle-tier infrastructure. As technology products approach the end of the product lifecycle, the project will continue to invest software and hardware function to run the business. This project also enables IT business operations to perform within prescribed CPU capacity, storage thresholds, system response times, and availability. Additionally, an opportunity arose to procure devices that had more capacity and capability than the infrastructure that was already in place as well as reduce the overall operational cost of maintaining the existing infrastructure as the new purchase included warranty.	Enables IT business operations to perform to the prescribed metrics and business analytics key performance index (KPIs) such as CPU capacity, storage thresholds, system response times, and availability.	Not Applicable	Technically not supported. Any production growth requirements would not affect a cloud solution strategy. EC	Yes	1/1/2023	12/31/2025	$ 657,760.00	$ 487,587.62	$ (158,088.67)	$ 524,462.00	$ 17,697.00	$ 3,400.00	$ 49,927.01	$ 170,191.93	$ 12,898.65	$ 157,259.00		$ 98.10		$ 131,201.65
234	2026	Production Growth	Sustainment	Electric	Plant and Field	Steve Ambrose	DHMD001675	Level 3	Approved in U-21460																					
235	2027	Production Growth	Sustainment	Electric	Plant and Field	Steve Ambrose	DHMD001775	Level 3	This project will deliver the infrastructure capacity and performance enhancements necessary to sustain business-critical operations as demand continues to grow. Specifically, the initiative will provision additional computing power, storage capacity, database availability, and middle-tier infrastructure ensuring that resources scale appropriately with usage. The scope is directly tied to supporting key business applications and processes, including meter reads, outage management, field service, and asset health management. By aligning capital investment with measurable workload growth in these areas, the project ensures that system performance, scalability, reliability, and availability targets are maintained. In addition, the project will: Ensure system performance remains within defined CPU, memory, and response time thresholds. Support business growth without compromising system reliability. Accommodate a growing user base and expanding usage across the enterprise.	Enables IT business operations to perform to the prescribed metrics and business analytics key performance index (KPIs) such as CPU capacity, storage thresholds, system response times, and availability.	Not Applicable	We did not select a "do nothing" approach because it would increase the risk of interruption of internal and external services due to infrastructure capacity failures. Due to the nature of this program, there are no alternative technology solutions that would provide a meaningful alternate course of action either physically or financially. A cloud solution strategy. EDRI - GIS - the upgraded version is on-premise. Although we talk about a	No	1/1/2027	12/31/2027	$ 1,298,999.41	$ 1,283,623.21	$ 758,264.90	$ 117,200.00			$ 458,418.31	$ 18,048.20	$ 18,048.20					$ 18,048.20
236	2028	Production Growth	Sustainment	Electric	Plant and Field	Steve Ambrose	DHMD003632	Level 3	Project will be processed by sub-Air Time computing power, storage capacity, database availability, and middle-tier infrastructure. As technology products approach the end of the product lifecycle, the project will continue to invest software and hardware function to run the business. This project also enables IT business operations to perform within prescribed CPU capacity, storage thresholds, system response times, and availability. Additionally, an opportunity arose to procure devices that had more capacity and capability than the infrastructure that was already in place as well as reduce the overall operational cost of maintaining the existing infrastructure as the new purchase included warranty.	Enables IT business operations to perform to the prescribed metrics and business analytics key performance index (KPIs) such as CPU capacity, storage thresholds, system response times, and availability.	Not Applicable	Technically not supported. Any production growth requirements would not affect a cloud solution strategy. EC	No	1/1/2028	12/31/2028	$ 1,299,554.69	$ 1,282,795.15	$ 544,197.10	$ 378,000.00			$ 380,556.05	$ 18,399.54	$ 18,399.54					$ 18,399.54
237	2025	Renewable Operations Application Health	Sustainment	Electric	Plant and Field	Steve Ambrose	DHMD0001695	Actual	Approved in U-21460																					
238	2026	Renewable Operations Application Health	Sustainment	Electric	Plant and Field	Steve Ambrose	DHMD0002376	Level 3	Approved in U-21460																					
239	2027	Renewable Operations Application Health	Sustainment	Electric	Plant and Field	Steve Ambrose	DHMD002376	Level 3	The recommendation is to sustain reliability, security and compliance of wind and solar park assets. This will be achieved through planned application upgrades, IT coordination and patching support. 2028 Scope: - Continued support for portfolio applications. - Infrastructure support for the current wind and solar generating sites. - Infrastructure support for new upcoming projects. o New Solar Sites: Granot (30 MW), Bull Run (100 MW), Cedar Creek (200 MW), Bull Run (100 MW), Fish Creek (132 MW), Cedar Fields (128 MW), Pinesyde (117 MW), Bluestone (100 MW), Bachelor (200 MW), Au Gres (175 MW), Elmwood (129 MW), Strawboy (100 MW). 2029 Scope: - Continued support for portfolio applications. - Infrastructure support for the current wind and solar generating sites. - Infrastructure support for new upcoming projects. o New Solar Sites: Silver Creek (200 MW), Bull Run (100 MW), Cedar Fields (128 MW), Pinesyde (117 MW), Peshtigo (185 MW), Deckerville (200 MW), Au Gres (175 MW), Elmwood (135 MW), Strawboy (100 MW).	This business case will allow IT to support the function of existing applications, keep business processes running efficiently and meet business operational needs effectively.	Not Applicable	No alternatives are considered at this time as the current solution platform meets the business needs. The system is required to remain current to support up-to-date business processes, asset health, and support timely accurate execution of site system modifications. The Do Nothing alternative was not considered, as this is required to support to sustain and support ongoing business demand and the Renewable business operations will be adversely impacted. The Do Nothing alternative was not considered, as this is required to support to sustain and support ongoing business demand and the Renewable business operations will be adversely impacted.	computing has been reviewed and approved by ITS. It is a Hybrid asset with OnPrem as well as Cloud implemen	No	1/1/2026	12/31/2027	$ 208,890.43	$ 164,082.77	$ 102,341.17				$ 61,521.60	$ 43,807.66	$ 43,807.66					$ 43,807.66
240	2028	Renewable Operations Application Health	Sustainment	Electric	Plant and Field	Steve Ambrose	DHMD002014	Level 3	The recommendation is to sustain reliability, security and compliance of wind and solar park assets. This will be achieved through planned application upgrades, IT coordination and patching support. 2028 Scope: - Continued support for portfolio applications. - Infrastructure support for the current wind and solar generating sites. - Infrastructure support for new upcoming projects.	This business case will allow IT to support the function of existing applications, keep business processes running efficiently and meet business operational needs effectively.	specialized workload - stay on premise	computing has been reviewed and approved by ITS. It is a Hybrid asset with OnPrem as well as Cloud implemen	No	1/1/2028	12/31/2028	$ 236,930.12	$ 184,940.28	$ 114,400.75				$ 70,539.63	$ 51,989.75	$ 51,989.75					$ 51,989.75
241	2026	Storm Resiliency	Sustainment	Electric	Plant and Field	Steve Ambrose	DHMD0003465	Level 3	Approved in U-21460																					
242	2026	Storm Simulation Lab Application Health	Sustainment	Electric	Plant and Field	Steve Ambrose	DHMD004028	Level 3	Maintain and Update Existing Automated Tests Ensure all end-to-end and load tests created during the initial Storm Simulation Lab project (covering SOS, CSA, EDDP, ESB, Public Protection Chatbot, etc.) remain current as the associated applications evolve. All critical user flows coded will be maintained and updated, as the applications change. Additional end-to-end tests will also be written, to increase testing coverage. Continue expanding upon an automated load testing, achieving multiple storm profiles' simulations across various systems. Expand Test Coverage to New Applications and Modules Integrate additional systems planned for 2026 (e.g., LRPM, additional ADMS SQL modules, Storm Role Scheduling, and Crew Management) into the automated testing suite.	To the Organization: Preserves and expands the value of the initial Storm Simulation Lab investment Reduces risk of IT failures during catastrophic storms Enables proactive system remediation before real-world impact Supports DTE's strategic goals for grid resilience and storm readiness To the Customer: Improves accuracy and timeliness of outage communications Reduces service disruption and accelerates restoration efforts Builds trust by ensuring consistent performance of customer-facing systems during storm events To the Employee: Provides field crews and operations teams with reliable, web-tested tools during high-pressure events Reduces manual workarounds by ensuring systems function properly under load Empowers IT teams to proactively address performance gaps through simulation and automation	The primary alternative considered was to not establish a dedicated sustainment demand and instead rely on ad hoc and manual testing / support from project teams or individual application owners. This approach was rejected due to several risks: Lack of ownership for maintaining and updating automated tests Inconsistent test execution and simulation cycles High risk of regression as applications evolve without coordinated test updates Loss of storm readiness capability over time due to test and environment degradation Inability to manually test high volume of scenarios, exposing vulnerabilities This reactive model would undermine the resilience gains achieved by the Storm Simulation Lab and reintroduce operational risk during storm events.	Not Applicable	NA	Yes	1/1/2026	12/31/2026	$ 1,505,858.38	$ 1,505,858.38	$ 750,296.38	$ 330,000.00			$ 488,560.00	$ -	$ -					$ -
243	2027	Storm Simulation Lab Application Health	Sustainment	Electric	Plant and Field	Steve Ambrose	DHMD004175	Level 3	Maintain and Update Existing Automated Tests Ensure all end-to-end and load tests created during the initial Storm Simulation Lab project (covering SOS, CSA, EDDP, ESB, Public Protection Chatbot, etc.) remain current as the associated applications evolve. All critical user flows coded will be maintained and updated, as the applications change. Additional end-to-end tests will also be written, to increase testing coverage. Continue expanding upon an automated load testing, achieving multiple storm profiles' simulations across various systems. Expand Test Coverage to New Applications and Modules Integrate additional systems planned for 2026 (e.g., LRPM, additional ADMS SQL modules, Storm Role Scheduling, and Crew Management) into the automated testing suite.	To the Organization: Preserves and expands the value of the initial Storm Simulation Lab investment Reduces risk of IT failures during catastrophic storms Enables proactive system remediation before real-world impact Supports DTE's strategic goals for grid resilience and storm readiness To the Customer: Improves accuracy and timeliness of outage communications Reduces service disruption and accelerates restoration efforts Builds trust by ensuring consistent performance of customer-facing systems during storm events To the Employee: Provides field crews and operations teams with reliable, web-tested tools during high-pressure events Reduces manual workarounds by ensuring systems function properly under load Empowers IT teams to proactively address performance gaps through simulation and automation	The primary alternative considered was to not establish a dedicated sustainment demand and instead rely on ad hoc and manual testing / support from project teams or individual application owners. This approach was rejected due to several risks: Lack of ownership for maintaining and updating automated tests Inconsistent test execution and simulation cycles High risk of regression as applications evolve without coordinated test updates Loss of storm readiness capability over time due to test and environment degradation Inability to manually test high volume of scenarios, exposing vulnerabilities This reactive model would undermine the resilience gains achieved by the Storm Simulation Lab and reintroduce operational risk during storm events.	Not Applicable	NA	No	1/1/2027	12/31/2027	$ 1,514,788.64	$ 1,514,788.64	$ 520,626.38	$ 328,000.00			$ 355,160.58	$ -	$ -					$ -
244	2028	Storm Simulation Lab Application Health	Sustainment	Electric	Plant and Field	Steve Ambrose	DHMD004230	Level 3	Maintain and Update Existing Automated Tests Ensure all end-to-end and load tests created during the initial Storm Simulation Lab project (covering SOS, CSA, EDDP, ESB, Public Protection Chatbot, etc.) remain current as the associated applications evolve. All critical user flows coded will be maintained and updated, as the applications change. Additional end-to-end tests will also be written, to increase testing coverage. Continue expanding upon an automated load testing, achieving multiple storm profiles' simulations across various systems. Expand Test Coverage to New Applications and Modules Integrate additional systems planned for 2026 (e.g., LRPM, additional ADMS SQL modules, Storm Role Scheduling, and Crew Management) into the automated testing suite.	To the Organization: Preserves and expands the value of the initial Storm Simulation Lab investment Reduces risk of IT failures during catastrophic storms Enables proactive system remediation before real-world impact Supports DTE's strategic goals for grid resilience and storm readiness To the Customer: Improves accuracy and timeliness of outage communications Reduces service disruption and accelerates restoration efforts Builds trust by ensuring consistent performance of customer-facing systems during storm events To the Employee: Provides field crews and operations teams with reliable, web-tested tools during high-pressure events Reduces manual workarounds by ensuring systems function properly under load Empowers IT teams to proactively address performance gaps through simulation and automation	The primary alternative considered was to not establish a dedicated sustainment demand and instead rely on ad hoc and manual testing / support from project teams or individual application owners. This approach was rejected due to several risks: Lack of ownership for maintaining and updating automated tests Inconsistent test execution and simulation cycles High risk of regression as applications evolve without coordinated test updates Loss of storm readiness capability over time due to test and environment degradation Inability to manually test high volume of scenarios, exposing vulnerabilities This reactive model would undermine the resilience gains achieved by the Storm Simulation Lab and reintroduce operational risk during storm events.	Not Applicable	NA	No	1/1/2028	12/31/2028	$ 1,518,794.19	$ 1,518,982.69	$ 791,982.00	$ 365,000.00			$ 449,600.60	$ 2,931.60	$ 2,931.60					$ 2,931.60
245	2025	Jeminesy Control and Data Acquisition (SCADA) System Improvements	Sustainment	Electric	Plant and Field	Steve Ambrose	DHMD0001395	Actual	Approved in U-21460																					
246	2025	System Fossil Generation for Coal and Gas	Sustainment	Electric	Plant and Field	Steve Ambrose	DHMD0001436	Actual	Approved in U-21460																					
247	2026	System Fossil Generation for Coal and Gas	Sustainment	Electric	Plant and Field	Steve Ambrose	DHMD002274	Level 3	Approved in U-21460																					
248	2027	System Fossil Generation for Coal and Gas	Sustainment	Electric	Plant and Field	Steve Ambrose	DHMD002274	Level 3	The Company plans to continue monthly releases to all applicable systems. The Company also plans to retire the PlantView system by migrating business functions into our Plasmo system as a process improvement planned for asset management. Hardware and platform upgrades will also continue as end-of-life for support dates occur. 2028 Scope: - Ongoing updates and patches to Fossil Generation's application suite, including Aveva and Power Plant Management System (PSM), to ensure alignment with vendor releases and regulatory requirements. - Replace existing Oracle Reports to a modern solution like Power BI or Jasper Reports. - Replace end-of-life Power Plant Management System (PSM) supported platform; either Oracle APEX or a home grown Microsoft Power App. 2029 Scope: - Ongoing updates and patches to Fossil Generation's application suite, including Aveva and Power Plant Management System (PSM), to ensure alignment with vendor releases and regulatory requirements.	This business case will allow IT to support the function of existing applications, keep business processes running efficiently and meet business operational needs effectively. Continued application support by updating or replacing aging systems can translate directly into financial reporting impacts as in the case of PDP which stores the information to calculate heat rate and needs to be aligned to changes in our generation fleet.	Not Applicable	No alternatives considered at this time as current solution platform meets the business needs. System is required to remain current to support up-to-date business processes, asset health, and support timely accurate execution of the PDP corporate data store used for financial closing and regulatory reporting. The "do nothing" alternative would result in continued manual work between and outside of these systems, increasing workload, as well as the likelihood of error. This alternative was rejected due to the risk of PDP not supporting accurate classification and report formatting. Similarly, not continuing the work of updating or replacing aging systems can translate directly into financial reporting impacts as in the case of PDP which stores the information to calculate heat rate and needs to be aligned to changes in our generation fleet. Technology alternatives other than continuing forward with the current state, include alternatives to CADS, but is prohibitively expensive when totaling the software, vendor support, potential hardware purchases, licenses, and implementation costs. The Company finds the solutions provided through this investment to be the most cost-effective while also providing the needed feature set.	Not Applicable	This business case covers a project which adds capability to existing on-prem applications.	No	1/1/2026	12/31/2027	$ 529,913.24	$ 488,247.31	$ 266,001.83				$ 173,245.48	$ 60,865.83	$ 60,865.83					$ 60,865.83
249	2028	System Fossil Generation for Coal and Gas	Sustainment	Electric	Plant and Field	Steve Ambrose	DHMD002015	Level 3	The Company plans to continue monthly releases to all applicable systems. Hardware and platform upgrades will also continue as end-of-life for support dates occur. 2028 Scope: - Ongoing updates and patches to Fossil Generation's application suite, including Aveva and Power Plant Management System (PSM), to ensure alignment with vendor releases and regulatory requirements.	This business case will allow IT to support the function of existing applications, keep business processes running efficiently and meet business operational needs effectively. Continued application support by updating or replacing aging systems can translate directly into financial reporting impacts as in the case of PDP which stores the information to calculate heat rate and needs to be aligned to changes in our generation fleet.	Not Applicable	This business case covers a project which adds capability to existing on-prem applications.	No	1/1/2028	12/31/2028	$ 596,865.48	$ 528,976.48	$ 326,875.71				$ 202,100.75	$ 67,877.08	$ 67,877.08					$ 67,877.08

250	2025	System Outage Screen (SOS) Application Health	Sustainment	Electric	Plant and Field	Steve Ambrose	DHP0050023	Actual	This is an existing application - System Outage Screen that will: Integrate Real-Time Data: Centralize outage updates and integrate with systems like Electrical Dispatch and Outage Dashboards for improved visibility. Automate Crew Assignments: Optimize resource allocation and dispatch times through automated, geographically efficient crew assignments. This demand also supports defect resolution and monitoring for the existing SOS application.	Organization: Improved efficiency with streamlined workflows and optimized crew assignments. Enhanced reliability and safety through real-time data and better resource allocation. Customer: Faster restoration times reduce service disruptions. Clearer communication during outages improves customer satisfaction. Employee: Simplified workflows and real-time data access improve productivity. Better coordination enhances collaboration across teams.	Alternative approach would cause disturbances to our internal system, ability to serve our customers and have a safety impact to the company.	Standard market-based and/or commoditized non-core energy workload - deploy in commercial cloud	Application is using the Azure cloud infrastructure and aligned with the direction of all storm critical application	Yes	1/2/2025	12/31/2025	$ 930,258.00	$ 765,705.00	$ 92,504.31	$ 590,698.31	$ 4,715.00		$ 105,798.94	$ 138,553.85	$ 40,776.76	$ 95,742.82	$ 40.27			$ 138,553.85
251	2026	System Outage Screen (SOS) Application Health	Sustainment	Electric	Plant and Field	Steve Ambrose	DHP0050867	Level 3	The recommended solution is to implement the System Outage Screen (SOS) application, a web-based tool designed to improve outage restoration and operational workflows. The SOS application will: Streamline Workflows: Replace outdated manual processes with dynamic, real-time functionality for consistent and efficient outage management. Enhance User Experience: Provide a unified, intuitive interface for seamless operation in all scenarios. On top of these, this demand also covers defect resolution and monitoring for the existing SOS application.	Organization: Improved efficiency with streamlined workflows and optimized crew assignments. Enhanced reliability and safety through real-time data and better resource allocation. Customer: Faster restoration times reduce service disruptions. Clearer communication during outages improves customer satisfaction. Employee: Simplified workflows and real-time data access improve productivity. Better coordination enhances collaboration across teams.	Alternative approach would cause disturbances to our internal system, ability to serve our customers and have a safety impact to the company.	Standard market-based and/or commoditized non-core energy workload - deploy in commercial cloud	Application is using the Azure cloud infrastructure and aligned with the direction of all storm critical application	No	1/2/2026	12/31/2026	$ 1,945,904.40	$ 1,429,068.23	$ 274,417.25	$ 911,000.00			$ 243,651.00	$ 518,836.17	$ 348,836.17	$ 176,000.00				$ 518,836.17
252	2027	System Outage Screen (SOS) Application Health	Sustainment	Electric	Plant and Field	Steve Ambrose	DHP0050929	Level 3	The recommended solution is to maintain the System Outage Screen (SOS) application through continuous bug fixes, minor enhancements, infrastructure updates, and proactive operational support. These efforts will ensure the application's ongoing reliability, performance, and alignment with enterprise security and cloud compliance standards. The SOS application is hosted on the Microsoft Azure platform, which includes BI Azure Platform Services critical for day-to-day outage management operations. Sustaining these services ensures they are regularly updated with the latest vendor security patches and point releases, allowing the system to operate at expected service levels and avoid disruptions. Operational experience has demonstrated that throughout the year, unforeseen issues such as customer complaints, configuration changes, software version upgrades, and infrastructure maintenance (e.g., servers, databases) must be addressed to ensure the stability and functionality of SOS. Historically, the team manages: 50-60 requests annually for enhancements or business process changes 2-3 major infrastructure or application upgrades per year This demand includes: Support for hardware and environment upgrades Security vulnerability remediation Adoption of major and minor software releases Ongoing user support to respond to business needs, implement process improvements, drive productivity Key elements of the solution include: Supporting core outage restoration workflows by preserving essential functionality Addressing application issues reported during storm and non-storm operations Delivering targeted enhancements for improved crew assignment, job tracking, and free-text entry Primary user groups supported: Operations Assessment Office	Organization: Operational Efficiency: Streamlined data sharing and workflow automation improve decision making and crew allocation. Reliability and Safety: Enhanced outage information and crew dispatch decision board fewer outages and improved safety. Customers: Faster Response Times: Reduced downtime and quicker resolution of service issues. Enhanced Communication: Clearer and accurate information on service disruptions and maintenance. Employees: Empowered Field Operations: Mobile access to updated outage information improves efficiency and restoration. Simplified Workflows: Integration simplifies processes and enhances collaboration across departments.	Alternative approach would cause disturbances to our internal system, ability to serve our customers and have a safety impact to the company.	Standard market-based and/or commoditized non-core energy workload - deploy in commercial cloud	Application is using the Azure cloud infrastructure and aligned with the direction of all storm critical application	No	1/2/2027	12/31/2027	$ 1,963,505.82	$ 1,467,365.23	$ 364,022.40	$ 837,200.00			$ 266,542.82	$ 495,940.00	$ 244,940.00	$ 251,000.00				$ 495,940.00
253	2028	System Outage Screen (SOS) Application Health	Sustainment	Electric	Plant and Field	Steve Ambrose	DHP0050191	Level 3	The recommended solution is to maintain the System Outage Screen (SOS) application through continuous bug fixes, minor enhancements, infrastructure updates, and proactive operational support. These efforts will ensure the application's ongoing reliability, performance, and alignment with enterprise security and cloud compliance standards. The SOS application is hosted on the Microsoft Azure platform, which includes BI Azure Platform Services critical for day-to-day outage management operations. Sustaining these services ensures they are regularly updated with the latest vendor security patches and point releases, allowing the system to operate at expected service levels and avoid disruptions. Operational experience has demonstrated that throughout the year, unforeseen issues such as customer complaints, configuration changes, software version upgrades, and infrastructure maintenance (e.g., servers, databases) must be addressed to ensure the stability and functionality of SOS. Historically, the team manages: 50-60 requests annually for enhancements or business process changes 2-3 major infrastructure or application upgrades per year This demand includes: Support for hardware and environment upgrades Security vulnerability remediation Adoption of major and minor software releases Ongoing user support to respond to business needs, implement process improvements, drive productivity Key elements of the solution include: Supporting core outage restoration workflows by preserving essential functionality Addressing applications issues reported during storm and non-storm operations Delivering targeted enhancements for improved crew assignment, job tracking, and free-text entry Primary user groups supported: Employee Accountability Office	Organization: Operational Efficiency: Streamlined data sharing and workflow automation improve decision making and crew allocation. Reliability and Safety: Enhanced outage information and crew dispatch decision board fewer outages and improved safety. Customers: Faster Response Times: Reduced downtime and quicker resolution of service issues. Enhanced Communication: Clearer and accurate information on service disruptions and maintenance. Employees: Empowered Field Operations: Mobile access to updated outage information improves efficiency and restoration. Simplified Workflows: Integration simplifies processes and enhances collaboration across departments.	Alternative approach would cause disturbances to our internal system, ability to serve our customers and have a safety impact to the company.	Standard market-based and/or commoditized non-core energy workload - deploy in commercial cloud	Application is using the Azure cloud infrastructure and aligned with the direction of all storm critical application	No	1/2/2028	12/31/2028	$ 1,910,012.64	$ 1,469,322.34	$ 391,445.76	$ 790,000.00			$ 282,458.38	$ 444,890.60	$ 207,890.60	$ 237,000.00				$ 444,890.60
254	2025	Advance Metering Infrastructure Field Collection System	Return to Health	Shared	Plant and Field	Steve Ambrose	DHP0001366	Actual	Approved in U-21890																					
255	2027	DO Business Warehouse (DOBW) Replacement	Return to Health	Electric	Plant and Field	Steve Ambrose	DHP0003724	Level 3	The Distributed Operations Business Warehouse (DOBW) system is currently used to track costs, employees, purchase orders, purchase requisitions, work data, master material items, asset specifications, locations, service receipts, and organizational structure/hierarchy. The system is built on an old Oracle database and is no longer sufficient to meet the needs of the DO Business Unit because it is end of life, and its support is no longer scalable, efficient, or cost-effective. It is hindering the organization's ability to make informed decisions and operate effectively, and its associated reports and applications are difficult to maintain and support. The system is susceptible to errors and data inconsistencies as well as delays in processing and reporting data. Additionally, the system's outdated infrastructure poses risks to data integrity and security, and the lack of vendor support means it is not equipped to support the outdated system. The recommended solution for moving away from the end-of-life DO Business Warehouse (DOBW) system is to migrate its data to the Enterprise Data Lake and sidewalk reports and applications using modern reporting tools and technologies. The recommended solution for moving away from the end-of-life DO Business Warehouse (DOBW) system is to migrate its data to the Enterprise Data Lake and sidewalk reports and applications using modern reporting tools and technologies. The functionality this decision provides and manner in which we solve for the opportunity above will be further explained in the sections below.	The decommissioning of DOBW and moving to the Enterprise Data Lake aligns with the DO Business Unit's strategic goal of improving data-driven decision-making and optimizing business processes to reduce operating costs, improve quality, and increase reliability. By consolidating operational data into one supported location, the project will provide a centralized and more efficient system for tracking costs, purchases, work orders, assets, and organizational structure/hierarchy. This will enable more accurate, timely, and data-driven decisions across the organization, ultimately improve the reliability and quality of services. Additionally, the use of modern reporting tools and technologies will allow for faster and more accurate reporting, leading to more timely and effective decision making. Overall, this will support the DTE in being a leading provider of high-quality services while maximizing efficiency and reducing costs.	Technology alternatives would be either creating a new in-house data warehouse, or continuing to support the current Oracle database, which is nearing end of life. These alternatives are rejected because they both represent undue costs and disregard existing investment in the Enterprise Data Lake Architecture. This investment is an Enterprise-wide platform for Data Analytics and is already in use. Introduction of an additional tool or system would not be a prudent use of funds. The "Do nothing" alternative is similarly rejected as it would require the Company to continue maintaining an end-of-life system. The risk when doing this for any technology, is that the support for the software is not available to or capable of returning it to operations.	Standard market-based and/or commoditized non-core energy workload - deploy in commercial cloud	Solution recommended is in alignment with IT cloud computing strategy.	Yes	1/2/2027	12/31/2027	$ 314,275.88	$ 259,897.22	$ 135,312.36	$ 23,000.00	$ 2,050.00		$ 95,524.94	$ 58,378.64	$ 57,778.64	$ 600.00				$ 58,378.64
256	2025	EOL - Lose Return to Health	Return to Health	Electric	Plant and Field	Steve Ambrose	DHP0003447	Actual	Approved in U-21890																					
257	2025	Field Service Edge (FSE) Replacement	Return to Health	Electric	Plant and Field	Steve Ambrose	DHP0003449	Actual	Approved in U-21890																					
258	2025	Field Service Edge (FSE) Replacement - Clockwork	Return to Health	Electric	Plant and Field	Steve Ambrose	DHP0003450	Actual	Approved in U-21890																					
259	2026	Field Service Edge (FSE) Replacement - Clockwork	Return to Health	Electric	Plant and Field	Steve Ambrose	DHP0003450	Level 3	Approved in U-21890																					
260	2025	Fuel Supply (Fuel Fuel Management System)	Return to Health	Electric	Plant and Field	Steve Ambrose	DHP0001446	Actual	Approved in U-21890																					
261	2028	Generation Optimization and Energy Accounting Cloud Migration	Return to Health	Electric	Plant and Field	Steve Ambrose	DHP0004185	Level 2	PCO Energy Solutions is identified as the vendor. The solution is to migrate to PCO Cloud—a vendor-managed SaaS platform delivering Generation Optimization and Energy Accounting capabilities. This migration will leverage the existing PCO Energy Accounting, and shift infrastructure management, patching, upgrades, and specialized support to PCO's expert team. PCO Cloud delivers 99.9%+ uptime with 24/7/365 support, enables rapid deployment of new capabilities (4-8 sweeps vs. 6-12 months on-premises), and reduces dependencies on internal support while accessing PCO's deep PMSO domain expertise. This solves both the immediate infrastructure need and the long-term strategic direction. PCO's strategic direction is to offer all new functionality on their cloud environment which will require us to align to their direction to continue to build capabilities to meet MISO participation requirements. Execution of this demand enables the retirement of 24 servers approaching the end of extended support, significantly reducing DTE's cybersecurity exposure and associated market participation risk.	Organization: Improved reliability, reduced operational risk, and future-proofing of core systems. Customer: Enhanced system stability and support, minimizing risk of operational disruptions. Employee: Reduced burden on IT staff from manual patching and infrastructure management, allowing them to focus on value-driven initiatives. Improved productivity through reduced support incidents, improved deployment timelines, and lower risk of knowledge gaps.	Remain On-Premises (VMware/Azure Stack): Maintains control but faces rising costs, limited scalability, and support challenges. Migrate to Azure Cloud: Removes hardware management, enables scaling, limits access to new PCO's Cloud capabilities and does not address expertise support depth.	Standard market-based and/or commoditized non-core energy workload - deploy in commercial cloud		No	1/2/2028	12/31/2028	$ 3,985,766.54	$ 3,897,245.54	$ 465,702.30	$ 615,604.88		$ 2,091,543.98	$ 524,594.24	$ 88,521.00	$ 88,521.00				$ 88,521.00
262	2027	Maximo Uplift to Maximo Application Suite	Return to Health	Shared	Plant and Field	Steve Ambrose	DHP0003296	Level 3	The recommended solution for addressing the outdated Enterprise Work and Asset Management (EWAM) system involves the following steps: Assessment: Conduct a thorough analysis of current business processes and requirements. Identify key functionalities and integrations needed in the new system. Vendor Selection: Research and evaluate potential EAM vendors that offer modern, scalable solutions. Consider factors such as integration capabilities, user interfaces, mobile accessibility, security features, and compliance. Implementation Plan: Develop a detailed implementation plan, including timelines, milestones, and resource allocation. Ensure a phased rollout to minimize disruptions to current operations. Data Migration: Plan and execute a comprehensive data migration strategy to transfer data from the old system to the new system. Ensure data integrity and accuracy during the migration process. Training and Support: Provide extensive training for employees to familiarize them with the new system. Offer ongoing support and resources to address any issues or questions that arise. Testing and Quality Assurance: Conduct rigorous testing to ensure the new system functions as expected. Resolve any issues before full deployment. Ensure the system meets all business requirements and performs as expected. Go-Live and Monitoring: Execute the go-live plan and closely monitor the system's performance. Gather feedback from users and make necessary adjustments to optimize the system. Continuous Improvement: Establish a process for continuous improvement and regular updates to keep the system aligned with evolving business needs and technological advancements, during and after the project go-live.	Homogenizing the Enterprise Work and Asset Management (EWAM) system will bring significant benefits and value to the organization, customers, and employees: Organization: 1. Operational Efficiency: Streamlined workflows and improved integration with other systems will enhance overall efficiency. Reduced maintenance and support costs due to a more reliable and scalable system. 2. Cost Savings: Lower long-term operational costs through optimized asset management and reduced downtime. Decreased expenses related to maintaining and supporting an outdated system. 3. Data-Driven Insights: Advanced reporting and analytics capabilities will provide valuable insights for better decision-making. Improved data accuracy and accessibility will enhance strategic planning. 4. Compliance and Security: Enhanced security features will protect sensitive data and ensure compliance with regulatory standards. Reduced risk of data breaches and legal issues. Customer: 1. Improved Service Delivery: More efficient work order management will lead to timely and reliable service delivery. 2. Higher Satisfaction: Better service quality and responsiveness will increase customer satisfaction and loyalty. Proactive maintenance and quicker issue resolution will enhance the customer experience. Employee 1. Productivity and Engagement: A modern, user-friendly interface and mobile accessibility will improve employee productivity. Streamlined processes and reduced manual tasks will allow employees to focus on higher-value activities. 2. Training and Development: Comprehensive training on the new system will enhance employees' skills and knowledge. Ongoing support and resources will ensure employees can effectively use the system.	1. Do Nothing - Keep using the current system. No immediate costs or disruptions. But will need to run an unsupported version of the software. Deal with continued inefficiencies and increased compliance and security risks. As well as lower employee productivity and satisfaction. 2. Implement a New EAM System - Install a EAM system based on overgrowned business processes. Will be able to utilize modern features, better integration and will be scalable for future growth (cloud solution). It will require higher initial costs, potential disruptions, and will require extensive training. But the result will benefit the entire enterprise. 3. Custom Build Solution - Develop a custom solution. High development and maintenance costs. Longer implementation time and resource intensive. Each option has its pros and cons. Installing a new system offers the best balance of addressing current issues, supporting growth, and improving performance.	Standard market-based and/or commoditized non-core energy workload - deploy in commercial cloud	In the data center strategy utilizing current collaboration with Microsoft will help align to the Azure SaaS recommendation	No	1/2/2027	12/31/2029	$ 22,796,399.69	$ 16,984,763.00	$ 3,898,288.00	$ 10,223,600.00		$ 2,439,002.00	$ 2,265,412.00	$ 3,785,194.14	$ 4,603,384.05	$ 1,081,800.00		$ 115,000.00	$ 4,194,860.98
263	2028	Maximo Uplift to Maximo Application Suite	Return to Health	Shared	Plant and Field	Steve Ambrose	DHP0003296	Level 3	The recommended solution for addressing the outdated Enterprise Work and Asset Management (EWAM) system involves the following steps: Assessment: Conduct a thorough analysis of current business processes and requirements. Identify key functionalities and integrations needed in the new system. Vendor Selection: Research and evaluate potential EAM vendors that offer modern, scalable solutions. Consider factors such as integration capabilities, user interfaces, mobile accessibility, security features, and compliance. Implementation Plan: Develop a detailed implementation plan, including timelines, milestones, and resource allocation. Ensure a phased rollout to minimize disruptions to current operations. Data Migration: Plan and execute a comprehensive data migration strategy to transfer data from the old system to the new system. Ensure data integrity and accuracy during the migration process. Training and Support: Provide extensive training for employees to familiarize them with the new system. Offer ongoing support and resources to address any issues or questions that arise. Testing and Quality Assurance: Conduct rigorous testing to ensure the new system functions as expected. Resolve any issues before full deployment. Ensure the system meets all business requirements and performs as expected. Go-Live and Monitoring: Execute the go-live plan and closely monitor the system's performance. Gather feedback from users and make necessary adjustments to optimize the system. Continuous Improvement: Establish a process for continuous improvement and regular updates to keep the system aligned with evolving business needs and technological advancements, during and after the project go-live.	Homogenizing the Enterprise Work and Asset Management (EWAM) system will bring significant benefits and value to the organization, customers, and employees: Organization: 1. Operational Efficiency: Streamlined workflows and improved integration with other systems will enhance overall efficiency. Reduced maintenance and support costs due to a more reliable and scalable system. 2. Cost Savings: Lower long-term operational costs through optimized asset management and reduced downtime. Decreased expenses related to maintaining and supporting an outdated system. 3. Data-Driven Insights: Advanced reporting and analytics capabilities will provide valuable insights for better decision-making. Improved data accuracy and accessibility will enhance strategic planning. 4. Compliance and Security: Enhanced security features will protect sensitive data and ensure compliance with regulatory standards. Reduced risk of data breaches and legal issues. Customer: 1. Improved Service Delivery: More efficient work order management will lead to timely and reliable service delivery. 2. Higher Satisfaction: Better service quality and responsiveness will increase customer satisfaction and loyalty. Proactive maintenance and quicker issue resolution will enhance the customer experience. Employee 1. Productivity and Engagement: A modern, user-friendly interface and mobile accessibility will improve employee productivity. Streamlined processes and reduced manual tasks will allow employees to focus on higher-value activities. 2. Training and Development: Comprehensive training on the new system will enhance employees' skills and knowledge. Ongoing support and resources will ensure employees can effectively use the system.	1. Do Nothing - Keep using the current system. No immediate costs or disruptions. But will need to run an unsupported version of the software. Deal with continued inefficiencies and increased compliance and security risks. As well as lower employee productivity and satisfaction. 2. Implement a New EAM System - Install a EAM system based on overgrowned business processes. Will be able to utilize modern features, better integration and will be scalable for future growth (cloud solution). It will require higher initial costs, potential disruptions, and will require extensive training. But the result will benefit the entire enterprise. 3. Custom Build Solution - Develop a custom solution. High development and maintenance costs. Longer implementation time and resource intensive. Each option has its pros and cons. Installing a new system offers the best balance of addressing current issues, supporting growth, and improving performance.	Standard market-based and/or commoditized non-core energy workload - deploy in commercial cloud	In the data center strategy utilizing current collaboration with Microsoft will help align to the Azure SaaS recommendation	No	1/2/2028	12/31/2028	$ 27,018,712.14	$ 21,236,518.00	$ 4,518,504.00	$ 12,823,680.00		$ 2,439,002.00	$ 2,265,412.00	$ 3,785,194.14	$ 4,603,384.05	$ 1,081,800.00		$ 115,000.00	$ 4,194,860.98
264	2025	Maximo Platform Program	Return to Health	Shared	Plant and Field	Steve Ambrose	DHP0001392	Actual	Approved in U-21890																					
265	2027	Ferris Supply Chain Transformation	Strategic	Electric	Plant and Field	Steve Ambrose	DHP0003360	Level 3	Nuclear Maximo, SAP, and Data Power Integration Services will be customized and extended by Accenture, with new capabilities, automations, and integrations to address current Ferris Supply Chain system limitations, areas for improvement and potential human error traps inherent with managing SOCP regulatory compliance requirements that were duplicated in the Nuclear Maximo Enterprise Asset Management system during the migration of existing functionality from the shared Enterprise Maximo Platform to Nuclear Maximo. This initiative will enhance Ferris Supply Chain's Material Management, Work Scheduling, Work Management, and Operations procedures by reducing manual interventions, improving tracking capabilities, and reducing the technical complexity of managing multiple systems with inaccessible or conflicting information.	Empowering the Ferris Supply Chain to fulfill its mission with greater efficiency and impact—streamlining supply chain processes to ensure access to the right services and materials, precisely when and where they're needed. This drives operational cost reductions, enhances safety across Ferris operations, and strengthens overall reliability. By leveraging modern automation and enhanced data governance, we minimize support, customers experience improved service, and the organization maximizes its ability to deliver at the lowest life cycle cost.	No alternatives have been considered, as the application transformation enabled in the Nuclear Maximo Enterprise Asset Management System stands as the foundation for all integration and automation opportunities within this project. Nuclear Maximo was successfully implemented through two separate multi-year projects, demonstrating its capacity to support Ferris operations while enhancing system capabilities, and ensuring long-term sustainability. This transformation is essential in reinforcing strategic alignment and optimizing enterprise processes. The option of maintaining the current state of the Ferris Supply Chain Applications without implementing further enhancements was considered. This "do-nothing" approach would leave existing inefficiencies and risks unaddressed, continuing to strain operational processes, inventory accuracy, and regulatory compliance.	Does not follow cloud computing strategy - exception	Management. By leveraging these established infrastructure components, the implementation ensures seamless	No	1/2/2027	12/14/2027	$ 7,796,462.31	$ 7,082,461.41	$ 444,179.16	$ 5,927,000.00			$ 711,282.40	$ 764,030.79	$ 519,030.79	$ 585,000.00				$ 764,030.79
266	2025	Storm Simulation Lab	Strategic	Electric	Plant and Field	Steve Ambrose	DHP0003337	Actual	Approved in U-21890																					
267	2026	Customer Contact and Relationship Management	Regulatory/Compliance	Shared	Customer-F	Steve Ambrose	DHP0003365	Actual	Approved in U-21890																					
268	2025	MISP Customer - Requested Renewable Energy Projects	Regulatory/Compliance	Electric	Customer-F	Steve Ambrose	DHP0001265	Actual	Approved in U-21890																					
269	2026	MISP Customer - Requested Renewable Energy Projects	Regulatory/Compliance	Electric	Customer-F	Steve Ambrose	DHP0001265	Level 3	Enhance and develop within DTE's current SAP CR&B, SAP BW and SAP Commerce Cloud. FY26 scope: Enroll customers into unique customer-requested contracts for dedicated assets Create new billing options and formats Integrate generation data and hourly MISO price from the new solar parks into SAP Develop the MISO participation management process Create reporting capabilities with SAP BW and SAP analytics Cloud (SAC).	Fulfill the customer-related contracts to build a 450 Megawatt and a 400 Megawatt dedicated solar park for uniquely contracted customers. Through its MIGreenPower program, DTE to add 650 megawatts of new solar energy in Michigan for Ford, increasing the total amount of installed solar in Michigan by nearly 70% By 2025, every Ford vehicle manufactured in Michigan will be assembled with the equivalent of 100% carbon-free electricity, 10 years earlier than Ford's global goal. Ford's purchase of carbon-free electricity will avoid as much as 600,000 tons of carbon dioxide emissions While advancing Ford's progress towards carbon neutrality, the purchase will also create jobs and tax revenue in Michigan Stellantis partners with DTE Energy to add 400 megawatts of new solar projects in Michigan through DTE's MIGreenPower program Clean energy purchase is second largest of its kind in U.S. history Automaker aims to achieve carbon net zero emissions globally by 2038 Deal includes 76 southeast Michigan Stellantis sites By 2026, every Stellantis vehicle manufactured in the state will be assembled with the equivalent of 100% carbon-free electricity Additional customers will add additional 300 megawatts	No alternatives have been identified. Regarding Do Nothing - This is an MPSC requirement and DTE has to implement.	Specialized workload - stay on premise	The MISP functionality is already working in the SAP CR&B and SAP Analytics Cloud, and the scope of this business case is an additional functionality that is being added to the existing platform.	No	9/1/2023	12/30/2026	$ 6,198,064.66	$ 6,000,000.10	$ 316,237.25	$ 5,075,030.85			$ 608,732.00	$ 198,064.58	$ 127,558.83	$ 33,400.00	$ 25,905.75			$ 198,064.58
270	2027	MISP Customer - Requested Renewable Energy Projects	Regulatory/Compliance	Electric	Customer-F	Steve Ambrose	DHP0002728	Level 3	Enhance and develop within DTE's current SAP CR&B, SAP BW and SAP Commerce Cloud Create/enable the code required for Customer-Requested product into the existing SAP applications, to configure the new billing options, enroll, unenroll, add bill credits to invoices. Design, develop, test and deploy the content in the DTE MIGreenPower website for this new product offering. This will help the customer to understand what products that they can subscribe to. Design, develop, test and deploy business warehouse the necessary tables, data and queries for the required reports, that will inform on the customers enrollments, energy utilization and forecasting about the DTE MIGreenPower program.	DTE will achieve strategic growth in the renewable energy sector. Stellantis partners with DTE Energy to add 400 megawatts of new solar projects in Michigan through DTE's MIGreenPower program Clean energy purchase is second largest of its kind in U.S. history Automaker aims to achieve carbon net zero emissions globally by 2038 Deal includes 76 southeast Michigan Stellantis sites By 2026, every Stellantis vehicle manufactured in the state will be assembled with the equivalent of 100% carbon-free electricity Additional customers will add additional 300-400 megawatts	No alternatives have been identified. Regarding Do Nothing - This is an MPSC requirement and DTE has to implement.	Standard market-based and/or commoditized non-core energy workload - deploy in commercial cloud	ing in the SAP CR&B and SAP BW reporting, and the scope of this business case is an additional functionality that	No	1/3/2027	12/31/2028	$ 3,380,985.03	$ 3,000,985.03	$ 363,640.88	$ 2,112,473.20			$ 524,451.00	$ 300,000.00	$ 158,480.64	$ 141,519.18				$ 300,000.00
271	2028	MISP Customer - Requested Renewable Energy Projects	Regulatory/Compliance	Electric	Customer-F	Steve Ambrose	DHP0002728	Level 3	Enhance and develop within DTE's current SAP CR&B, SAP BW and SAP Commerce Cloud Create/enable the code required for Customer-Requested product into the existing SAP applications, to configure the new billing options, enroll, unenroll, add bill credits to invoices. Design, develop, test and deploy the content in the DTE MIGreenPower website for this new product offering. This will help the customer to understand what products that they can subscribe to. Design, develop, test and deploy business warehouse the necessary tables, data and queries for the required reports, that will inform on the customers enrollments, energy utilization and forecasting about the DTE MIGreenPower program.	DTE will achieve strategic growth in the renewable energy sector. Stellantis partners with DTE Energy to add 400 megawatts of new solar projects in Michigan through DTE's MIGreenPower program Clean energy purchase is second largest of its kind in U.S. history Automaker aims to achieve carbon net zero emissions globally by 2038 Deal includes 76 southeast Michigan Stellantis sites By 2026, every Stellantis vehicle manufactured in the state will be assembled with the equivalent of 100% carbon-free electricity Additional customers will add additional 300-400 megawatts	No alternatives have been identified. Regarding Do Nothing - This is an MPSC requirement and DTE has to implement.	Standard market-based and/or commoditized non-core energy workload - deploy in commercial cloud	ing in the SAP CR&B and SAP BW reporting, and the scope of this business case is an additional functionality that	No	1/3/2028	12/31/2028	$ 6,198,089.55	$ 5,998,543.22	$ 360,376.57	$ 5,114,715.65			$ 524,451.00	$ 199,546.33	$ 155,865.48	$ 30,680.84				$ 199,546.33
272	2026	MISP Large Customer Pre-Payment	Regulatory/Compliance	Shared	Customer-F	Steve Ambrose	DHP0001681	Level 3	Approved in U-21890																					
273	2027	MISP Law Income Solar Pilot	Regulatory/Compliance	Electric	Customer-F	Steve Ambrose	DHP0001685	Level 3	Enhance and develop within DTE's current SAP CR&B, SAP BW and SAP Commerce Cloud Fulfill the requirements in the section 81 settlement, August 2022	No alternatives identified. This is a tariff and this project must be completed to support low income solar pilot mandate.	Specialized workload - stay on premise	SAP BW reporting, DTE Website, SAP Commerce and IVR systems) and the scope of this business case is an add	No	2/1/2027	11/30/2027	$ 2,643,855.28	$ 2,273,722.16	$ 192,706.48	$ 1,718,909.39			$ 362,103.73	$ 179,133.08	$ 53,133.08	$ 117,000.00				$ 179,133.08
274	2027	MISP Scope 3 Billing and Enrollment	Regulatory/Compliance	Electric	Customer-F	Steve Ambrose	DHP0002493	Level 3	Enhance and develop within DTE's current SAP CR&B, SAP BW, SAP Commerce Cloud and SAP analytics cloud. Design, develop, test and deploy code required for Scope 3 initiatives in the existing SAP Applications to implement new billing options. Design, develop, test and deploy the content in the DTE MIGreenPower website for this new product offering. This will help the customer to understand what products that they can subscribe to. Design, develop, test and deploy business warehouse the necessary tables, data and queries for the required reports, that will inform on the customers enrollments, energy utilization and forecasting about the DTE MIGreenPower program. This will be implemented in a single release aligned with DTE release calendar.	Fulfill the requirements in the section 81 settlement.	No alternatives have been identified because SAP CR6 is the chosen platform for Customer relationship/billing services and offerings. Do Nothing was not an option and would result in noncompliance with MPSC and regulatory requirements.	Specialized workload - stay on premise	SAP CR&B, SAP BW reporting and SAP Commerce, the scope of this business case is an additional functionality t	No	2/1/2027	11/30/2027	$ 4,942,192.10	$ 4,556,292.75	$ 245,152.75	$ 3,866,760.00		$ 58,000.00	$ 375,350.00	$ 385,829.43	$ 125,829.43	$ 260,000.00				$ 385,829.43
275	2025	Regulatory Compliance	Regulatory/Compliance	Shared	Customer-F	Steve Ambrose	DHP0001384	Actual	Approved in U-21890																					
276	2026	Regulatory Compliance	Regulatory/Compliance	Electric	Customer-F	Steve Ambrose	DHP0002758	Level 3	Approved in U-21890																					
277	2027	Regulatory Compliance	Regulatory/Compliance	Electric	Customer-F	Steve Ambrose	DHP0002758	Level 3	Once it has been involved, the BRM will work with the external vendor to determine what solution is required in order to meet the required MPSC approve rate order.	This investment ensures that all Regulatory policies and processes are in place and in compliance. As a result, DTE remains in compliance with the Commission Orders, and avoids the risk of non-compliance.	N/A	No cloud implementation is currently in scope for this effort.	No	1/3/2026	12/31/2027	$ 3,273,590.32	$ 2,872,194.96	$ 14,112.00	$ 2,798,799.98			$ 149,245.00	$ 400,033.36		$ 400,033.36				$ 400,033.36
278	2028	Regulatory Compliance	Regulatory/Compliance	Electric	Customer-F	Steve Ambrose	DHP0004233	Level 3	This business case provides capacity to support emergent regulatory work, including compliance with Commission Orders issued in general rate cases and other proceedings, as well as unplanned activities driven by new energy legislation. The volume and timing of regulatory requirements vary from year to year. In 2025, DTE completed several planned and unplanned regulatory initiatives. These included the removal of IEE SumCheck, which improved operational efficiency and reduced the need for manual bill corrections that previously contributed to delayed billing. The company also implemented the Residential Electric Vehicle Time-of-Use rate pilot, which offers customers a lower rate, launched the Ford Pinto TCU and OLLO Commercial TOU rates, and deployed enhancements to the Michigan Energy Assistance Program (MEAP), which provides energy assistance and self-sufficiency services to eligible low income households across the state. In addition, DTE transitioned customers from rate D1, D1x to D1.1 following approval from the MPSC. Further updates included electric and gas rate changes to revise or amend rate schedules and the rates governing the distribution and supply of energy. Other projects delivered in 2025 addressed billing violations that contribute to delayed or incorrect bills. Collectively, these efforts support DTE's continued modernization of the state's energy grid and improvements to electric storage and generation systems, enhancing overall reliability and customer experience. Once it has been involved, the BRM will work with the external vendor to determine what solution is required in order to meet the required MPSC approve rate order.	This investment ensures that all Regulatory policies and processes are in place and in compliance. As a result, DTE remains in compliance with the Commission Orders, and avoids the risk of non-compliance.	No other alternatives have been considered as this investment is required to remain in compliance with Commission Orders and any legislative requirements. If Regulatory changes are not implemented, DTE could become non-compliant with Commission Orders or legislative requirements. To 'Do Nothing' would result in DTE falling out of compliance and thus incurring potential fines.	N/A	No cloud implementation is currently in scope for this effort.	No	1/3/2028	12/31/2028	$ 3,273,101.95	$ 2,872,141.80	$ 28,537.80	$ 2,671,500.00			$ 173,304.00	$ 400,960.00	$ 3,760.00	$ 396,200.00				$ 400,960.00
279	2025

281	2027	Rider 17 – MGreenPower, Residential and Small Commercial & Industrial	Regulatory/Compliance	Electric	Customer IT	Steve Ambrose	DMND0002726	Level 3	Enhance and develop within DTE's current SAP CR&B, SAP BW, SAP Commerce cloud, EMARSYS and SAP Analytics cloud. Create' design and incorporate the code required for this initiative in the existing SAP Applications to implement new billing options. Design, develop, test and deploy the content in the DTE MGreenPower website for this new product offering. This will help the customer to understand what products that they can subscribe to. Design, develop, test and deploy business warehouse the necessary tables, data and queries for the required reports, that will inform on the customers enrollments, energy utilization and forecasting about the DTE MGreenPower program. This will be implemented by aligning with DTE release calendar.	Fulfill the requirements in the section 61 settlement as well as any other things or MPSC requests that will be filed. This is to fulfill the Renewable energy initiative for the customers. Revenue growth and Customer satisfaction. To remain incompliance with any MPSC order.	No alternatives have been identified. Do Nothing was not an option and would result in noncompliance with MPSC and regulatory requirements.	Standard market-based and/or commoditized non-core energy workload - deploy in commercial cloud	SAP CR&B, SAP BW reporting and SAP Commerce, the scope of this business case is an additional functionality t	No	1/2/2027	12/31/2028	$ 3,417,725.98	$ 3,137,725.98	$ 274,255.96	$ 2,426,166.38		$ 437,208.00	$ 280,000.00	$ 217,800.00	$ 62,200.00				$ 280,000.00
282	2028	Rider 17 – MGreenPower, Residential and Small Commercial & Industrial	Regulatory/Compliance	Electric	Customer IT	Steve Ambrose	DMND0002726	Level 3	Enhance and develop within DTE's current SAP CR&B, SAP BW, SAP Commerce cloud, EMARSYS and SAP Analytics cloud. Create' design and incorporate the code required for this initiative in the existing SAP Applications to implement new billing options. Design, develop, test and deploy the content in the DTE MGreenPower website for this new product offering. This will help the customer to understand what products that they can subscribe to. Design, develop, test and deploy business warehouse the necessary tables, data and queries for the required reports, that will inform on the customers enrollments, energy utilization and forecasting about the DTE MGreenPower program. This will be implemented by aligning with DTE release calendar.	Fulfill the requirements in the section 61 settlement as well as any other things or MPSC requests that will be filed. This is to fulfill the Renewable energy initiative for the customers. Revenue growth and Customer satisfaction. To remain incompliance with any MPSC order.	No alternatives have been identified. Do Nothing was not an option and would result in noncompliance with MPSC and regulatory requirements.	Standard market-based and/or commoditized non-core energy workload - deploy in commercial cloud	SAP CR&B, SAP BW reporting and SAP Commerce, the scope of this business case is an additional functionality t	No	1/2/2027	12/31/2028	$ 5,191,761.31	$ 4,905,145.45	$ 271,425.45	$ 4,198,510.30		$ 437,208.00	$ 286,611.96	$ 145,911.90	$ 140,700.00				$ 286,611.96
283	2027	ADM License Renewal	Sustainment	Shared	Customer IT	Steve Ambrose	DMND0004112	Level 3	The demand is to cover a 3-year capital cost for the license procurement of Adobe Experience Manager (AEM) which is a digital customer experience platform that enables Corporate Communications to author and publish static web content to DTE's customer web channel, dtewesgo.com. This licensing was last purchased in 2024. This is a critical business application for DTE's Corporate Communications to author and publish DTE's Web Content. This is a critical business application for Corporate Communications to manage customer facing web content. The recommended solution is to pay for these services thus locking in continued subscription costs and capitalizing on the licensing agreement to avoid service disruption.	Cloud services will remain and no disruption to those applications that are dependent on these services.	A "do nothing" alternative is not in scope. DTE must react and comply with requirements imposed by legal and governmental entities. If we do nothing the necessary business processes changes in associated systems to avoid manual workarounds which add operational overhead.	Core energy management or cyber security system - stay on premise	T Cloud Strategy for supporting non-ECC SAP functionality for those applications that are not customized and can	No	1/2/2027	12/31/2027	$ 1,818,057.00	$ 1,818,057.00	$ 14,592.00		$ 1,768,000.00	$ 103,975.00	$ -					$ -
284	2025	Business Planning and Development (BPD) and Electric Sales & Marketing (EDM) Application Health	Sustainment	Electric	Customer IT	Steve Ambrose	DMND0001246	Actual	Approved in U-21080																					
285	2026	Business Planning and Development (BPD) and Electric Sales & Marketing (EDM) Application Health	Sustainment	Electric	Customer IT	Steve Ambrose	DMND0002700	Level 3	Approved in U-21080																					
286	2027	Cloud Services Application Health - Cloud Platform Enterprise Agreement (CPEA)	Sustainment	Electric	Customer IT	Steve Ambrose	DMND0004151	Level 3	The recommended solution is to pay for these services thus locking in discounted costs on the licensing agreement to avoid service disruption. The solution will also continue investing in upgrades and application development required to keep the cloud solutions for above application systems up and running.	Cloud services will remain and no disruption to those applications that are dependent on these services. SAP BTP acts as the technology foundation that unifies applications, data, analytics, AI, automation, and integration. Its benefits span across the entire enterprise ecosystem from business operations to workforce efficiency to customer experience. The platform unifies SAP and non-SAP systems, reducing fragmentation, data silos, and redundant processes. Organization benefits are higher Return on Investments, integrated landscape, fewer sin solutions, faster innovation, improved efficiency. Employee benefits are unified data access, reduced manual work, faster decision-making, enhanced collaboration, and the ability to introduce personalized services for accessing accurate information and services thus resulting in better user experiences.	A "do nothing" alternative is not in scope. DTE must react and comply with requirements imposed by legal and governmental entities. If we do nothing the necessary business processes changes in associated systems to avoid manual workarounds which add operational overhead. The solution will also continue investing in upgrades and application development required to keep the cloud solutions for above application systems up and running.	Standard market-based and/or commoditized non-core energy workload - deploy in commercial cloud	T Cloud Strategy for supporting non-ECC SAP functionality for those applications that are not customized and can	No	3/1/2027	3/31/2027	$ 1,003,363.00	$ 1,003,363.00				$ 932,700.00	$ 70,663.00	$ -					$ -
287	2025	Contact Center Application Health	Sustainment	Shared	Customer IT	Steve Ambrose	DMND0001264	Actual	Approved in U-21080																					
288	2026	Contact Center Application Health	Sustainment	Shared	Customer IT	Steve Ambrose	DMND0002714	Level 3	Approved in U-21080																					
289	2027	Contact Center Application Health	Sustainment	Shared	Customer IT	Steve Ambrose	DMND0002714	Level 3	The solution is to continue investing in upgrades and security vulnerability remediation required to keep the Contact Center telephony and integrated Voice Response (IVR) systems up and running. This work can include minor and major software and hardware upgrades, modifying code or configuration as required to address significant issues or outages. These systems are critical to the Contact Center business processes and are used by over 1,000 users daily. This work also includes the internal systems that interact with our platform. Some activities may be done in partnership with our supporting vendors. Annually there are roughly 15-20 builds and deployments to manage enhancements and upgrades. This requires services to build, test and deploy into production.	Customers are able to self-serve via the IVR and reach a representative if need be. Representatives are able to take calls both remotely and onsite at DTE based on their circumstances. The value to Contact Center leadership is their ability to monitor call volume, change call routing, and manage their day-to-day operations. The Contact Center platform is sustained in a way that meets service level expectations.	A "do nothing" alternative is not in scope. DTE must react and comply with requirements imposed by legal and governmental entities. If we do nothing the necessary business processes changes in associated systems to avoid manual workarounds which add operational overhead. The solution will also continue investing in upgrades and security vulnerability remediation required to keep the Contact Center telephony and integrated Voice Response (IVR) systems up and running. This work can include minor and major software and hardware upgrades, modifying code or configuration as required to address significant issues or outages. These systems are critical to the Contact Center business processes and are used by over 1,000 users daily. This work also includes the internal systems that interact with our platform. Some activities may be done in partnership with our supporting vendors.	Core energy management or cyber security system - stay on premise	Currently the Contact Center Platform is using the Nice cloud telephony system.	Yes	1/2/2026	12/30/2027	$ 2,150,735.88	$ 1,403,486.00	$ 55,310.76	$ 1,125,802.20	$ 115,069.04		$ 105,367.00	$ 791,255.88	$ 9,512.04	$ 791,743.84				$ 572,889.26
290	2028	Contact Center Application Health	Sustainment	Shared	Customer IT	Steve Ambrose	DMND0004237	Level 3	The solution is to continue investing in upgrades and security vulnerability remediation required to keep the Contact Center telephony and integrated Voice Response (IVR) systems up and running. This work can include minor and major software and hardware upgrades, modifying code or configuration as required to address significant issues or outages. These systems are critical to the Contact Center business processes and are used by over 1,000 users daily. This work also includes the internal systems that interact with our platform. Some activities may be done in partnership with our supporting vendors. Annually there are roughly 15-20 builds and deployments to manage enhancements and upgrades. This requires services to build, test and deploy into production.	Customers are able to self-serve via the IVR and reach a representative if need be. Representatives are able to take calls both remotely and onsite at DTE based on their circumstances. The value to Contact Center leadership is their ability to monitor call volume, change call routing, and manage their day-to-day operations. The Contact Center platform is sustained in a way that meets service level expectations.	A "do nothing" alternative is not in scope. DTE must react and comply with requirements imposed by legal and governmental entities. If we do nothing the necessary business processes changes in associated systems to avoid manual workarounds which add operational overhead. Applications with diagnostic and platform will not be running on the latest releases/patches which could impact security and application performance. It is critical that we capture business process changes in all associated systems to avoid manual workarounds which add operational overhead.	Core energy management or cyber security system - stay on premise	Currently the Contact Center Platform is using the Nice cloud telephony system.	Yes	1/2/2028	12/30/2029	$ 2,209,010.00	$ 1,386,184.00	$ 52,646.00	$ 1,148,660.00	$ 120,060.00		$ 86,746.00	$ 818,018.00	$ 8,216.00	$ 811,530.00				$ 593,546.76
291	2026	Customer Insight Platform Application Health	Sustainment	Electric	Customer IT	Steve Ambrose	DMND0002716	Level 3	Powerley has developed and supports several systems used by DTE's external customers (e.g. DTE Insight, Energy Bridges, Bill Management, and Powerley Portal). These systems needs to be maintained and upgraded to support new mobile operating systems or DTE's external customers' ever changing business needs. Powerley's Cloud Systems and needs to provide the required support services to maintain the solutions provided by Powerley. Annually this project will engage Powerley as they are the owners of the platform used to ensure DTE customers do not see any interruptions for DTE Insight, Energy Bridges, Bill Management, and Powerley Portal.	Ensures no interruption to DTE customers using included apps	Investigated alternatives including bringing the capability in house, determined that the lowest risk option is to continue with Powerley	Standard market-based and/or commoditized non-core energy workload - deploy in commercial cloud	Powerley cloud platform the solutions were originally developed on. That cloud platform is provided as a service t	No	1/2/2026	12/31/2027	$ 1,868,886.82	$ 1,796,473.46	$ 268,679.46	$ 1,248,603.00		$ 242,094.00	$ 195,413.36	$ 1,413.36	$ 99,000.00				$ 195,413.36
292	2027	Customer Insight Platform Application Health	Sustainment	Shared	Customer IT	Steve Ambrose	DMND0002716	Level 3	Powerley has developed and supports several systems used by DTE's external customers (e.g. DTE Insight, Energy Bridges, Bill Management, and Powerley Portal). These systems needs to be maintained and upgraded to support new mobile operating systems or DTE's external customers' ever changing business needs. Powerley's Cloud Systems and needs to provide the required support services to maintain the solutions provided by Powerley. Annually this project will engage Powerley as they are the owners of the platform used to ensure DTE customers do not see any interruptions for DTE Insight, Energy Bridges, Bill Management, and Powerley Portal.	Ensures no interruption to DTE customers using included apps	Investigated alternatives including bringing the capability in house, determined that the lowest risk option is to continue with Powerley	Standard market-based and/or commoditized non-core energy workload - deploy in commercial cloud	Powerley cloud platform the solutions were originally developed on. That cloud platform is provided as a service t	No	1/2/2026	12/31/2027	$ 1,861,013.15	$ 1,790,388.15	$ 287,064.55	$ 1,250,493.00		$ 242,094.00	$ 195,024.46	$ 814.46	$ 99,200.00				$ 195,024.46
293	2028	Customer Insight Platform Application Health	Sustainment	Shared	Customer IT	Steve Ambrose	DMND0004218	Level 3	Funding supports the following: Mobile app enhancements for iOS and Android OS compatibility updates (annual major releases + monthly patches) Security vulnerability monitoring and mitigation Energy Bridge firmware development and maintenance Additional customer engagement tools (surveys, feedback, etc.) Powerley Portal enhancements and backend integration support Customer experience improvements and new feature development	A. Customer Benefits Accurate real-time energy visibility Reduced billing confusion Enhanced self-service options that call center requires Improved budgeting and energy management outcomes B. Operational Benefits Higher digital engagement and self-service Supports Demand Response programs and load management Reduces manual intervention and technical escalations Ensures cybersecurity compliance C. Strategic Benefits Strengthens DTE's competitive position Supports customer satisfaction and regulatory performance indicators Provides a scalable foundation for future digital innovations	Without continued investment: Apps may fail on updated iOS/Android versions Firmware may lose compatibility with DTE systems Security vulnerabilities may increase operational risk Real-time energy usage may be inaccurate or unavailable Customer satisfaction could decline sharply Contact center volume will increase as customers engage questions Program benefits (e.g., Demand Response savings) may be reduced These risks directly affect customer trust and DTE's operational performance.	Customer Systems are non-core and can use public cloud	No	1/2/2028	12/31/2028	$ 2,396,743.10	$ 2,100,002.00	$ 343,482.00	$ 1,420,000.00		$ 337,201.00	$ 295,060.00	$ 3,060.00	$ 292,000.00				$ 213,657.60
294	2025	Customer Notifications Application Health	Sustainment	Shared	Customer IT	Steve Ambrose	DMND0001508	Actual	Approved in U-21080																					
295	2026	Customer Notifications Application Health	Sustainment	Shared	Customer IT	Steve Ambrose	DMND0001508	Level 3	Approved in U-21080																					
296	2027	Customer Notifications Application Health	Sustainment	Shared	Customer IT	Steve Ambrose	DMND0002592	Level 3	Ongoing support for the Convey Message Broadcast platform is essential. Ensuring qualified staff are available to manage and refine these systems will help maintain a consistent customer experience and optimize the value of previous investments. Recommended Solution includes the following: - Bug fixes that will surface throughout the year - Enhancements to modify existing or to create new notification campaigns for email, phone or SMS. These are received throughout the year from business partners as opportunities are identified. - Reporting enhancements as requested by business partners for tracking the customer journey and customer responses, creation of ad updates to reports/dashboards to monitor system performance, creation of automated alerts when an issue occurs so it can be fixed timely, etc.	Sustaining the notification systems and processes ensures reliable communication, regulatory compliance, and improved operational efficiency for all stakeholders.	No alternatives have been identified; dedicated sustainment resources are required to support current systems and processes. Do nothing: The application would hopefully continue to function as is, but the business would no longer have the ability to create any new notification campaigns. This would result in a very poor customer experience impacting MPS and lead to more calls to the Contact Center. This may also hinder our ability to communicate to customers for 'emergency' related events and some regulatory required events, which could lead to fines being assessed.	Standard market-based and/or commoditized non-core energy workload - deploy in commercial cloud	Proposed solution will utilize the public cloud and will be a certified SAP both on application.	No	1/2/2027	12/31/2028	$ 2,498,999.93	$ 1,499,399.68	$ 102,659.22	$ 1,053,767.46		$ 253,575.00	$ 1,010,000.20	$ 195,588.50	$ 226,412.00		$ 585,988.98		$ 731,240.10
297	2028	Customer Notifications Application Health	Sustainment	Shared	Customer IT	Steve Ambrose	DMND0002592	Level 3	Ongoing support for the Convey Message Broadcast platform is essential. Ensuring qualified staff are available to manage and refine these systems will help maintain a consistent customer experience and optimize the value of previous investments. Recommended Solution includes the following: - Bug fixes that will surface throughout the year - Enhancements to modify existing or to create new notification campaigns for email, phone or SMS. These are received throughout the year from business partners as opportunities are identified. - Reporting enhancements as requested by business partners for tracking the customer journey and customer responses, creation of ad updates to reports/dashboards to monitor system performance, creation of automated alerts when an issue occurs so it can be fixed timely, etc.	Sustaining the notification systems and processes ensures reliable communication, regulatory compliance, and improved operational efficiency for all stakeholders.	No alternatives have been identified; dedicated sustainment resources are required to support current systems and processes. Do nothing: The application would hopefully continue to function as is, but the business would no longer have the ability to create any new notification campaigns. This would result in a very poor customer experience impacting MPS and lead to more calls to the Contact Center. This may also hinder our ability to communicate to customers for 'emergency' related events and some regulatory required events, which could lead to fines being assessed.	Standard market-based and/or commoditized non-core energy workload - deploy in commercial cloud	Proposed solution will utilize the public cloud and will be a certified SAP both on application.	No	1/2/2027	12/31/2028	$ 1,736,001.68	$ 1,266,004.32	$ 398,008.32	$ 826,769.00		$ 253,575.00	$ 386,001.36	$ 101,869.26	$ 59,500.00		$ 207,659.00		$ 376,464.68
298	2025	Customer Relationship and Billing Program	Sustainment	Shared	Customer IT	Steve Ambrose	DMND0001259 DMND0001260	Actual	Automated Application Monitoring: The recommended solution for this problem is to continue to implement and expand the capabilities of SAP Solution Manager and Dynatrace throughout the Customer portfolio of applications, systems, interfaces and environments. 2024 Expand SAP Solution Manager to include Business Intelligence Monitoring 2025 Adjust monitoring configuration to support core CR&B Pro-Active Operational activities CIT Configuration Management - The recommended solution is for DTE's change management framework to evolve to include Agile methodologies, Digital Factories, Cloud environments/applications/adapters, SOX self testing automation and the new capabilities, competencies and tools to support said evolution. While maintaining existing capabilities, tools, technologies and competencies: Configuration, release, and change management of the entire CIT portfolio of assets, including CR&B, self-service channels, EDB, and all BPD assets Support a well-managed CIT and BOP Portfolio of assets that are in compliance with all regulatory requirements Schedule, coordinate and support configuration, build, and deployment for the needs of application teams, business partners, and our customer Operate, self test and participate in audits of owned and operated SOX controls	The value of this project is having a highly available Customer Relationship & Billing production environment that meets the needs of our customers and employees CIT Configuration Management- The Customer or employee value of this project is configuration, build, and deployment in line with the needs of application teams, business partners, and our customers, resulting in reduced planned and unplanned downtime and zero compliance issues across the CIT and BPD portfolios of assets. Closed Loop COCI, Application The value of this project is to have channel interactions that operate smoothly and efficiently providing a good experience for our customers Customer Legacy Application & Automated Application Monitoring Maintain customer legacy systems so they operate smoothly and efficiently providing a good experience for our customers and employee users Improve CR&B Uptime % - 1% The Customer or employee value is configuration and deployment in line with application operations, business operations resulting in reduced unplanned downtime. Success for this initiative would reduce the number of unplanned application and business process outage(s), reduce the duration of unplanned outage(s), and optimized business process operations(s)&(t).	Not Applicable	No cloud implementation or new initiatives will be considered scope of the sustainment activity				$ 7,407,219.00	$ 6,421,996.75	$ 112,277.67	$ 5,278,072.81	$ 551,424.50	$ 3,294.94	$ 478,877.00	$ 985,263.11	$ 21,632.11	$ 1,001,422.39	$ 1,990.00	$ (39,786.19)		$ 1,910,344.92
299	2026	Customer Relationship and Billing Program	Sustainment	Shared	Customer IT	Steve Ambrose	DMND0003809DMND0003856	Level 3	Provide the necessary resource capacity necessary to sustain the Customer Relationship & Billing production environment to enable high availability and accuracy so systems are available 24/7 365 days a year. Complete required changes to software or system as requested through build, test and deployment changes to all environments Modify applications to improve performance and reliability post incident remediation Provide resources to apply, test and deploy technical patch updates to the application environments Provide resources for the required code and/or configuration deployment to production landscape and support production readiness Provide Resources to manage project compliance requirements through delivery Provide technical project design resource capacity Perform ongoing cyclical and non-cyclical operational activities for applications allowing effective system maintenance Application Lifecycle Management (ALM) manages all enhancement request and request that require 24 hrs of development to 120 hrs of development are prioritized within monthly build cycles. Each build to production deployment consumes 500 hrs of total development, testing and production builds. There are 12 production releases planned per year. The recommended solution for the problem is to continue to implement and expand the capabilities of SAP Solution Manager and Dynatrace throughout the Customer portfolio of applications, systems, interfaces and environments. Expand SAP Solution Manager to include Business Intelligence Monitoring Adjust monitoring configuration to support core CR&B Pro-Active Operational activities The recommended solution is for DTE's change management framework to evolve to include Agile methodologies, Digital Factories, Cloud environments/applications/adapters, SOX self testing automation and the new capabilities, competencies and tools to support said evolution.	The value of this project is having a highly available Customer Relationship & Billing production environment that meets the needs of our customers and employees The Customer or employee value of this project is configuration, build, and deployment in line with the needs of application teams, business partners, and our customers, resulting in reduced planned and unplanned downtime and zero compliance issues across the CIT and BPD portfolios of assets. The value of this project is to have channel interactions that operate smoothly and efficiently providing a good experience for our customers Maintain customer legacy systems so they operate smoothly and efficiently providing a good experience for our customers and employee users	Not Applicable	No cloud implementation or new initiatives will be considered scope of the sustainment activity	Yes	1/5/2026	12/30/2026	$ 8,710,226.78	$ 6,035,961.47	$ 380,963.30	$ 4,870,333.36	$ 224,166.72		$ 556,098.00	$ 2,694,875.31	$ 814,808.71	$ 1,880,066.60				$ 1,910,344.92
300	2027	Customer Relationship and Billing Program	Sustainment	Shared	Customer IT	Steve Ambrose	DMND0003809DMND0003856	Level 3	Provide the necessary resource capacity necessary to sustain the Customer Relationship & Billing production environment to enable high availability and accuracy so systems are available 24/7 365 days a year. Complete required changes to software or system as requested through build, test and deployment changes to all environments Modify applications to improve performance and reliability post incident remediation Provide resources to apply, test and deploy technical patch updates to the application environments Provide resources for the required code and/or configuration deployment to production landscape and support production readiness Provide Resources to manage project compliance requirements through delivery Provide technical project design resource capacity Perform ongoing cyclical and non-cyclical operational activities for applications allowing effective system maintenance Application Lifecycle Management (ALM) manages all enhancement request and request that require 24 hrs of development to 120 hrs of development are prioritized within monthly build cycles. Each build to production deployment consumes 500 hrs of total development, testing and production builds. There are 12 production releases planned per year. The recommended solution for the problem is to continue to implement and expand the capabilities of SAP Solution Manager and Dynatrace throughout the Customer portfolio of applications, systems, interfaces and environments. Expand SAP Solution Manager to include Business Intelligence Monitoring Adjust monitoring configuration to support core CR&B Pro-Active Operational activities The recommended solution is for DTE's change management framework to evolve to include Agile methodologies, Digital Factories, Cloud environments/applications/adapters, SOX self testing automation and the new capabilities, competencies and tools to support said evolution.	The value of this project is having a highly available Customer Relationship & Billing production environment that meets the needs of our customers and employees The Customer or employee value of this project is configuration, build, and deployment in line with the needs of application teams, business partners, and our customers, resulting in reduced planned and unplanned downtime and zero compliance issues across the CIT and BPD portfolios of assets. The value of this project is to have channel interactions that operate smoothly and efficiently providing a good experience for our customers Maintain customer legacy systems so they operate smoothly and efficiently providing a good experience for our customers and employee users	Not Applicable	No cloud implementation or new initiatives will be considered scope of the sustainment activity	Yes	1/5/2026	12/30/2026	$ 9,010,005.98	$ 6,320,270.07	$ 369,171.96	$ 5,171,732.36	$ 224,166.72		$ 554,198.00	$ 2,694,735.91	$ 655,969.31	$ 1,874,684.60				$ 1,910,344.92
301	2028	Customer Relationship and Billing Program	Sustainment	Shared	Customer IT	Steve Ambrose	DMND0003809DMND0003856	Level 3	Provide the necessary resource capacity necessary to sustain the Customer Relationship & Billing production environment to enable high availability and accuracy so systems are available 24/7 365 days a year. Complete required changes to software or system as requested through build, test and deployment changes to all environments Modify applications to improve performance and reliability post incident remediation Provide resources to apply, test and deploy technical patch updates to the application environments Provide resources for the required code and/or configuration deployment to production landscape and support production readiness Provide Resources to manage project compliance requirements through delivery Provide technical project design resource capacity Perform ongoing cyclical and non-cyclical operational activities for applications allowing effective system maintenance Application Lifecycle Management (ALM) manages all enhancement request and request that require 24 hrs of development to 120 hrs of development are prioritized within monthly build cycles. Each build to production deployment consumes 500 hrs of total development, testing and production builds. There are 12 production releases planned per year. The recommended solution for the problem is to continue to implement and expand the capabilities of SAP Solution Manager and Dynatrace throughout the Customer portfolio of applications, systems, interfaces and environments. Expand SAP Solution Manager to include Business Intelligence Monitoring Adjust monitoring configuration to support core CR&B Pro-Active Operational activities The recommended solution is for DTE's change management framework to evolve to include Agile methodologies, Digital Factories, Cloud environments/applications/adapters, SOX self testing automation and the new capabilities, competencies and tools to support said evolution.	The value of this project is having a highly available Customer Relationship & Billing production environment that meets the needs of our customers and employees The Customer or employee value of this project is configuration, build, and deployment in line with the needs of application teams, business partners, and our customers, resulting in reduced planned and unplanned downtime and zero compliance issues across the CIT and BPD portfolios of assets. The value of this project is to have channel interactions that operate smoothly and efficiently providing a good experience for our customers Maintain customer legacy systems so they operate smoothly and efficiently providing a good experience for our customers and employee users	Not Applicable	No cloud implementation or new initiatives will be considered scope of the sustainment activity	Yes	1/5/2026	12/30/2028	$ 9,014,403.37	$ 6,326,100.08	$ 367,774.24	$ 5,187,003.28	$ 224,166.96		$ 566,228.00	$ 2,694,303.29	$ 654,794.41	$ 1,879,544.47				$ 1,910,475.98
302	2025	Digital Channels Application Health	Sustainment	Shared	Customer IT	Steve Ambrose	DMND0002741	Actual	Approved in U-21080																					
303	2026	Digital Channels Application Health	Sustainment	Shared	Customer IT	Steve Ambrose	DMND0002741	Level 3	Procures a small technical team to deliver ongoing enhancements to portions of the customer website. Specifically, this team will develop new components, as needed, for the Adobe Experience Cloud platform that hosts all static customer content and digital assets. Additionally, this team will regularly release enhancements to the portions of the website that are running on the legacy IBM WebSphere Portal platform, including customer account landing page, billing and payment history, payment program management, rebates, energy usage, landlord management, and commercial and industrial account management. In addition to monthly releases, this team will also address breaks/fix items and provide 24/7 production support. Source a small team (approx. 8 FTEs) of developers and testers, with a team lead. This team will be skilled in Adobe Experience Cloud, IBM WebSphere and WebSphere Portal, Java, CSS, and JavaScript in order to deliver monthly improvements to the website. This investment supports development, testing, and project management to deliver monthly software releases for 2025, 2026, 2027 and 2028. The scope of each release is prioritized monthly, with enhancements prioritized based on the following metrics: Digital Engagement Rate, Transaction Completion Rate, Defect reduction, Customer Complaint reduction, System Availability, Planned Outage reduction, Unplanned Outage reduction.	Employee Value: Incident Prediction for timely maintenance; Incident Remediation to avoid similar problems; System break / fix assistance; Availability Management to avoid outages; System Health Oversight by easily monitoring operation. Customer Value: Experience fewer outages and the ability to complete a full transaction without interruption. Improved customer experience ratings, to the website.	Alternatives Considered: 1) Over time, DTE staff to take on work typically provided by PSA. 2) Halt support of digital web channel If nothing is done to ensure PSA continued oversight and maintenance, then unplanned outages, fewer web engagements, customer inconvenience would reflect through low reputation rating against DTE Energy.	Standard market-based and/or commoditized non-core energy workload - deploy in commercial cloud	Invest with cloud strategy and runs on the public cloud. Portions of the site running on IBM WebSphere and WebSp	No	1/2/2025	12/30/2028	$ 1,848,916.01	$ 1,877,537.72	-$ 43,125.66	$ 1,516,260.00		$ 106,364.04	$ 193,278.29	$ 10,826.25	$ 158,750.54				$ 122,629.88
304	2027	Digital Channels Application Health	Sustainment	Shared	Customer IT	Steve Ambrose	DMND0002741	Level 3	Procures a small technical team to deliver ongoing enhancements to portions of the customer website. Specifically, this team will develop new components, as needed, for the Adobe Experience Cloud platform that hosts all static customer content and digital assets. Additionally, this team will regularly release enhancements to the portions of the website that are running on the legacy IBM WebSphere Portal platform, including customer account landing page, billing and payment history, payment program management, rebates, energy usage, landlord management, and commercial and industrial account management. In addition to monthly releases, this team will also address breaks/fix items and provide 24/7 production support. Source a small team (approx. 8 FTEs) of developers and testers, with a team lead. This team will be skilled in Adobe Experience Cloud, IBM WebSphere and WebSphere Portal, Java, CSS, and JavaScript in order to deliver monthly improvements to the website. This investment supports development, testing, and project management to deliver monthly software releases for 2025, 2026, 2027 and 2028. The scope of each release is prioritized monthly, with enhancements prioritized based on the following metrics: Digital Engagement Rate, Transaction Completion Rate, Defect reduction, Customer Complaint reduction, System Availability, Planned Outage reduction, Unplanned Outage reduction.	Employee Value: Incident Prediction for timely maintenance; Incident Remediation to avoid similar problems; System break / fix assistance; Availability Management to avoid outages; System Health Oversight by easily monitoring operation. Customer Value: Experience fewer outages and the ability to complete a full transaction without interruption. Improved customer experience ratings,	Alternatives Considered: 1) Over time, DTE staff to take on work typically provided by PSA. 2) Halt support of digital web channel If nothing is done to ensure PSA continued oversight and maintenance, then unplanned outages, fewer web engagements, customer inconvenience would reflect through low reputation rating against DTE Energy.	Standard market-based and/or commoditized non-core energy workload - deploy in commercial cloud	Invest with cloud strategy and runs on the public cloud. Portions of the site running on IBM WebSphere and WebSp	No	1/2/2026	12/30/2028	$ 1,944,311.00	$ 1,678,897.88	$ 48,250.44	$ 1,516,260.00		$ 106,364.04	$ 168,503.32	$ 9,752.28	$ 158,750.54				$ 121,896.40
305	2028	Digital Channels Application Health	Sustainment	Shared	Customer IT	Steve Ambrose	DMND0002741	Level 3	Procures a small technical team to deliver ongoing enhancements to portions of the customer website. Specifically, this team will develop new components, as needed, for the Adobe Experience Cloud platform that hosts all static customer content and digital assets. Additionally, this team will regularly release enhancements to the portions of the website that are running on the legacy IBM WebSphere Portal platform, including customer account landing page, billing and payment history, payment program management, rebates, energy usage, landlord management, and commercial and industrial account management. In addition to monthly releases, this team will also address breaks/fix items and provide 24/7 production support. Source a small team (approx. 8 FTEs) of developers and testers, with a team lead. This team will be skilled in Adobe Experience Cloud, IBM WebSphere and WebSphere Portal, Java, CSS, and JavaScript in order to deliver monthly improvements to the website. This investment supports development, testing, and project management to deliver monthly software releases for 2025, 2026, 2027 and 2028. The scope of each release is prioritized monthly, with enhancements prioritized based on the following metrics: Digital Engagement Rate, Transaction Completion Rate, Defect reduction, Customer Complaint reduction, System Availability, Planned Outage reduction, Unplanned Outage reduction.	Employee Value: Incident Prediction for timely maintenance; Incident Remediation to avoid similar problems; System break / fix assistance; Availability Management to avoid outages; System Health Oversight by easily monitoring operation. Customer Value: Experience fewer outages and the ability to complete a full transaction without interruption. Improved customer experience ratings,	Alternatives Considered: 1) Over time, DTE staff to take on work typically provided by PSA. 2) Halt support of digital web channel If nothing is done to ensure PSA continued oversight and maintenance, then unplanned outages, fewer web engagements, customer inconvenience would reflect through low reputation rating against DTE Energy.	Standard market-based and/or commoditized non-core energy workload - deploy in commercial cloud	Invest with cloud strategy and runs on the public cloud. Portions of the site running on IBM WebSphere and WebSp	No	1/2/2025	12/30/2028	$ 1,842,828.13	$ 1,674,866.88	$ 47,436.76	$ 1,516,260.00		$ 106,364.21	$ 167,897.16	$ 9,137.28	$ 158,749.88				$ 121,550.20
306	2025	Hybris Application Health	Sustainment	Electric	Customer IT	Steve Ambrose	DMND0002276	Actual	The recommended solution to the problem is to provide the necessary resource capacity and services to apply, test and deploy SAP's release(s) to all environments. The schedule will be based off the vendors release schedule to ensure the platform continues to support the self service needs of our customers. These are currently planned to be rolled out on a quarterly basis. This will provide the necessary labor services to build, test and deploy the planned major upgrades and enhancements in the Hybris Cloud Platform. This will also provide the necessary sustainment services for achieving the require SLA's on the cloud platform through Ukeplatse services contract.	"1. Enabling business to roll-out products and offer services without needing support from IT 2. Improved user interface - dashboard view vs. emailed report 3. Targeted troubleshooting and faster root cause analysis. 4. Low configuration solutions (i.e., less administrative work), and reducing waste. "	This is a application health project and hence the alternative is to continue with business requiring IT support for introducing new products and services which can be expensive and time-consuming DO Nothing Alternative was not accepted as it will not enable IT to support the business	Standard market-based and/or commoditized non-core energy workload - deploy in commercial cloud	Proposed solution is built on existing SAP Customer Cloud Platform hosted on Azure.	Yes	1/2/2023	12/31/2025	$ 2,902,679.94	$ 2,296,532.97	$ 60,092.47	$ 2,060,574.82	$ 10,722.68		$ 158,543.00	$ 662,346.97	$ (11,317.70)	$ 203,750.47	$ 1.15	$ 409,913.05		$ 662,346.97
307	2026	Hybris Application Health	Sustainment	Shared	Customer IT	Steve Ambrose	DMND0002732	Level

308	2025	MiGreenPower Program Stabilization	Sustainment	Electric	Customer-IT	Steve Ambrose	OHMD0001759	Actual	Develop within DTE's current SAP CR&B, SAP ISU, SAP BW, SAP Commerce Cloud and SAP Marketing cloud. Design, develop, test and deploy the new solar park node into the existing CSB0 billing system, to bill credits/invoices. Design, develop, test and deploy business warehouse functionalities that will inform on the customers enrollments, energy utilization and forecasting about the DTE MiGreenPower program. Leverage vendor partner relationships to staff and support this request. This will be implemented in multiple releases aligned with DTE release calendar which is monthly by our external vendor partner.	Continuing to create program options for the MiGreenPower will drive program growth, improve customer satisfaction and experience. The customer value is improved system functionality alignment to business process in sync customer data and billing. To provide necessary Employee tools to administer the MiGreenPower program. The employee value is improved employee work experience by minimizing the amount of manual work arounds.	No alternatives have been identified. A do-nothing approach will result in a discrepancy in several business processes. Data, business and reports will continue to utilize inaccurate data which could lead to program inefficiency, and failure to fulfill audit to MPSC requirements.	Specialized workload - stay on premise	CR&B, SAP ISU, Commerce cloud and SAP Marketing Cloud; and the scope of this business case is fixing the exis	Yes	1/1/2024	12/30/2025	$ 2,861,278.03	$ 1,796,978.34	$ 13,279.39	$ 1,482,317.51	$ 8,243.08	$ 0.36	$ 189,547.39	$ 279,790.24	$ 34,372.66	$ 236,327.41	$ 0.17		$ 279,790.24
309	2026	MiGreenPower Program Stabilization	Sustainment	Electric	Customer-IT	Steve Ambrose	OHMD0001759	Level 3	Approved in U-21080																					
310	2025	Outage WSPMO, PPS, and Map Application Health	Sustainment	Electric	Customer-IT	Steve Ambrose	OHMD0001064	Actual	The proposed solution provides the following functionality/capabilities: 2025 Make necessary modifications to the service layers when DTE switches to new OMS system in 2023, which also enables a seamless transition to the Customer facing channels. Outage Map provides ease of use, outage information whenever is available, alerting customers with banner messages, understand the previous storm patterns to improve the OMS. Migration of PPS to WSPMO Modification of business logic on top of the Outage Data Repository to identify customer Outage status, System will handle customers reporting trouble behind trouble and prioritize their outage accordingly. 2026 Maintenance of new customer status service layer to expose data for all endpoints consumption. Make necessary modifications to the service layers when DTE switches to new OMS system in 2023, which also enables a seamless transition to the Customer facing channels.	The proposed solution provides confidence every customer is accounted for, accurate data for outage communications, consistent data to all endpoints and accurate restoration times. Specific scope will be based on where we stand as of 2Q24 and what is needed to reach our long term targets and customer and MPSC expectations. Restoration Communication Accuracy & Timeliness. Long Term Target – To maintain a Power Restoration Accuracy of 98% and improve timeliness to identify the customer's power status to 5 minutes or less. Outage Notification Delivery. Long Term Target – The Company is targeting to increase the percentage of customers with reported outages successfully receiving outage status notifications to 98%. First Estimate Accuracy. Long Term Target – The Company is targeting 85% First Estimate Accuracy during all storms, to be delivered to the customer within 4 hours of the customer's power being lost. Outage Digital Companion Rate Targets 2024: 50%, 2025: Inspiration: 97% Digital Engagement Rate Targets 2024: 34%, 2025 Inspiration: 98%	A "do nothing" alternative would result in gaps in outage management requirements and could result in unpatched customer experience. Also, we will not have access to security upgrades, vulnerabilities that may be exploited by hackers to access and disrupt DTE's system	Standard market-based and/or commoditized non-core energy workload - deploy in commercial cloud	Because Customer Applications and Customer Data is non-core and hosted in public cloud	Yes	1/6/2025	12/17/2026	$ 3,674,227.10	$ 3,351,528.48	$ 231,269.43	$ 2,610,872.48	$ 12,518.45	$ 111.98	$ 496,721.50	$ 322,708.09	$ 7,865.97	$ 154,682.03	$ 31.28	$ 0.00	$ 322,708.09
311	2026	Outage WSPMO, PPS, and Map Application Health	Sustainment	Electric	Customer-IT	Steve Ambrose	OHMD0001064	Level 3	The proposed solution provides the following functionality/capabilities: 2025 Make necessary modifications to the service layers when DTE switches to new OMS system in 2023, which also enables a seamless transition to the Customer facing channels. Outage Map provides ease of use, outage information whenever is available, alerting customers with banner messages, understand the previous storm patterns to improve the OMS. Migration of PPS to WSPMO Modification of business logic on top of the Outage Data Repository to identify customer Outage status, System will handle customers reporting trouble behind trouble and prioritize their outage accordingly. 2026 Maintenance of new customer status service layer to expose data for all endpoints consumption. Make necessary modifications to the service layers when DTE switches to new OMS system in 2023, which also enables a seamless transition to the Customer facing channels. Migration of PPS to WSPMO	The proposed solution provides confidence every customer is accounted for, accurate data for outage communications, consistent data to all endpoints and accurate restoration times. Specific scope will be based on where we stand as of 2Q24 and what is needed to reach our long term targets and customer and MPSC expectations. Restoration Communication Accuracy & Timeliness. Long Term Target – To maintain a Power Restoration Accuracy of 98% and improve timeliness to identify the customer's power status to 5 minutes or less. Outage Notification Delivery. Long Term Target – The Company is targeting to increase the percentage of customers with reported outages successfully receiving outage status notifications to 98%. First Estimate Accuracy. Long Term Target – The Company is targeting 85% First Estimate Accuracy during all storms, to be delivered to the customer within 4 hours of the customer's power being lost. Outage Digital Companion Rate Targets 2024: 50%, 2025: Inspiration: 97% Digital Engagement Rate Targets 2024: 34%, 2025 Inspiration: 98%	A "do nothing" alternative would result in gaps in outage management requirements and could result in unpatched customer experience. Also, we will not have access to security upgrades, vulnerabilities that may be exploited by hackers to access and disrupt DTE's system	Standard market-based and/or commoditized non-core energy workload - deploy in commercial cloud	Because Customer Applications and Customer Data is non-core and hosted in public cloud	No	1/6/2025	12/17/2026	$ 6,406,404.28	$ 5,249,984.85	$ 381,252.85	$ 4,520,590.58			$ 348,137.59	$ 249,486.64	$ 29,496.45	$ 159,593.04			$ 249,486.64
312	2027	Outage WSPMO, PPS, and Map Application Health	Sustainment	Electric	Customer-IT	Steve Ambrose	OHMD0003842	Level 3	The proposed solution provides the following functionality/capabilities: 2027 Make necessary modifications to the service layers when OMS makes any enhancements, which would be a seamless transition to the Customer facing channels. Outage Map provides ease of use, outage information whenever is available, alerting customers with banner messages, understand the previous storm patterns to improve the OMS. Mapping of PPS into WSPMO Modification of business logic on top of the Outage Data Repository to identify customer Outage status, System will handle customers reporting trouble behind trouble and prioritize their outage accordingly. 2028 Maintenance of new customer status service layer to expose data for all endpoints consumption. Make necessary modifications to the service layers when DTE switches to new OMS system in 2023, which also enables a seamless transition to the Customer facing channels.	The proposed solution provides confidence every customer is accounted for, accurate data for outage communications, consistent data to all endpoints and accurate restoration times. Specific scope will be based on where we stand as of 2Q24 and what is needed to reach our long term targets and customer and MPSC expectations. Restoration Communication Accuracy & Timeliness. Long Term Target – To maintain a Power Restoration Accuracy of 98% and improve timeliness to identify the customer's power status to 5 minutes or less. Outage Notification Delivery. Long Term Target – The Company is targeting to increase the percentage of customers with reported outages successfully receiving outage status notifications to 98%. First Estimate Accuracy. Long Term Target – The Company is targeting 85% First Estimate Accuracy during all storms, to be delivered to the customer within 4 hours of the customer's power being lost. Outage Digital Companion Rate Targets 2024: 50%, 2027: Inspiration: 97% Digital Engagement Rate Targets 2024: 34%, 2027 Inspiration: 98%	A "do nothing" alternative would result in gaps in outage management requirements and could result in unpatched customer experience. Also, we will not have access to security upgrades, vulnerabilities that may be exploited by hackers to access and disrupt DTE's system	Standard market-based and/or commoditized non-core energy workload - deploy in commercial cloud	Because Customer Applications and Customer Data is non-core and hosted in public cloud	No	1/4/2027	12/31/2027	$ 5,713,841.10	$ 5,173,298.00	$ 338,675.06	$ 4,000,595.00			$ 373,501.39	$ 538,575.09	$ 38,575.85	$ 590,000.00			$ 538,575.09
313	2028	Outage WSPMO, PPS, and Map Application Health	Sustainment	Electric	Customer-IT	Steve Ambrose	OHMD0004217	Level 3	The 2028 program will include: Application Enhancements Minor functional enhancements to PPS, WSPMO, and Outage Map (each requiring ~80 development hours) - Updates to the WSPMO Mobile App (ZP-WSPMO-APP) to maintain alignment with the web platform Cloud & Security Compliance Periodic Azure Cloud resource updates required to maintain platform compliance and security posture Remediation of identified vulnerabilities to protect customer data and maintain operational integrity. Performance Improvement Optimization of the Outage Map load process to improve real-time data refresh and response during high outage events Execution of two load tests (or more if you'd like to specify), simulating up to one million outages to validate scalability Nexus Delivery Up to 24 releases in 2028 to support upgrades, fixes, and enhancements.	Operational Benefits Increased customer outage storms Improved processing speed for outage data Sustained support for the 48 hour restoration KPI Customer Benefits Reduce self-service outage reporting Real-time and accurate outage data on the Outage Map Increased customer satisfaction and reduced contact center volume Technology & Security Benefits Reduced risk of system failures and downtime by remediation Continued Azure compliance, preventing unexpected service disruption Improved system performance under severe load conditions Long Term Target – To maintain a Power Restoration Accuracy of 98% and improve timeliness to identify the customer's power status to 5 minutes or less. Outage Notification Delivery. Long Term Target – The Company is targeting to increase the percentage of customers with reported outages successfully receiving outage status notifications to 98%. First Estimate Accuracy. Long Term Target – The Company is targeting 85% First Estimate Accuracy during all storms, to be delivered to the customer within 4 hours of the customer's power being lost. Outage Digital Companion Rate Targets 2028: 50%, 2028: Inspiration 97% Digital Engagement Rate Targets 2024: 34%, 2028:Inspiration 98%	A "do nothing" alternative would result in gaps in outage management requirements and could result in unpatched customer experience. Also, we will not have access to security upgrades. Potential system outages or degraded performance during major storms Inability for customers to report or view outages through digital channels Increased customer dissatisfaction Security vulnerabilities accumulating due to missed updates Possible non-compliance with Azure requirements, resulting in forced and costly emergency upgrades Higher risk of failing outage restoration KPIs	Standard market-based and/or commoditized non-core energy workload - deploy in commercial cloud	Customer Applications and Customer Data is non-core and hosted in public cloud	No	1/3/2028	12/31/2028	$ 5,748,745.00	$ 4,102,545.00	$ 266,836.00	$ 3,725,000.00			$ 477,215.00	$ 1,246,700.00	$ 7,700.00	$ 1,230,000.00			$ 1,246,700.00
314	2025	Powerley Customer Platform Application Health	Sustainment	Shared	Customer-IT	Steve Ambrose	OHMD0002596	Actual	Approved in U-21080																					
315	2027	SAP EIP Cloud Applications Health	Sustainment	Shared	Customer-IT	Steve Ambrose	OHMD0004150	Level 3	The recommended solution to the problem is to provide the necessary resource capacity and services to apply, test and deploy SAP's releases(s) to all environments. This schedule will be based off the vendors release schedule to ensure the platform continues to support the self-service needs of DTE's customers. These are currently planned to be rolled out on a quarterly basis. This will provide the necessary labor services to build, test and deploy the planned major upgrades and enhancements in the SAP EIP Cloud Platform. This will also provide the necessary sustainment services for achieving the required SLA's on the cloud platform through vendor services contract. By keeping the version of the software up to date DTE will be able to continue to deploy new projects required by business. Scope for 2027 - Monthly SAP EIP Cloud Platform enhancements & Feature patches in support of services - Support of moving on-prem services to EIP cloud-based operations (e.g. Process Orchestration, Business Warehouse) Scope for 2028 - Monthly SAP EIP Cloud Platform enhancements & Feature patches in support of services - Continuation of support of moving on-prem services to EIP cloud-based operations (e.g. Process Orchestration, Business Warehouse)	Customer: Secured digital channel access Effective personalized customer communication Organization: Streamline business processes Improved customer experience Improve speed to market Employee: Enabling business to roll-out products and offer services without needing support from IT Improved user interface - dashboard view vs. emailed report Targeted troubleshooting and faster root cause analysis Low configuration solutions (i.e., less administrative work) and reducing waste.	This is an application health project and hence the alternative is to continue with business requiring IT support for introducing new products and services which can be expensive and time consuming. DO Nothing alternative is not accepted as it will not enable IT to support existing business processes.	Standard market-based and/or commoditized non-core energy workload - deploy in commercial cloud	Proposed solution is built on existing SAP CH Cloud Platform hosted on Azure.	No	1/4/2027	12/31/2028	$ 1,142,534.14	$ 1,027,305.12	$ 179,165.16	$ 796,799.96			$ 141,400.00	$ 115,228.02	$ 27,029.02	$ 88,200.00			$ 83,425.74
316	2028	SAP EIP Cloud Applications Health	Sustainment	Shared	Customer-IT	Steve Ambrose	OHMD0004150	Level 3	The recommended solution to the problem is to provide the necessary resource capacity and services to apply, test and deploy SAP's releases(s) to all environments. This schedule will be based off the vendors release schedule to ensure the platform continues to support the self-service needs of DTE's customers. These are currently planned to be rolled out on a quarterly basis. This will provide the necessary labor services to build, test and deploy the planned major upgrades and enhancements in the SAP EIP Cloud Platform. This will also provide the necessary sustainment services for achieving the required SLA's on the cloud platform through vendor services contract. By keeping the version of the software up to date DTE will be able to continue to deploy new projects required by business. Scope for 2027 - Monthly SAP EIP Cloud Platform enhancements & Feature patches in support of services - Support of moving on-prem services to EIP cloud-based operations (e.g. Process Orchestration, Business Warehouse) Scope for 2028 - Monthly SAP EIP Cloud Platform enhancements & Feature patches in support of services - Continuation of support of moving on-prem services to EIP cloud-based operations (e.g. Process Orchestration, Business Warehouse)	Customer: Secured digital channel access Effective personalized customer communication Organization: Streamline business processes Improved customer experience Improve speed to market Employee: Enabling business to roll-out products and offer services without needing support from IT Improved user interface - dashboard view vs. emailed report Targeted troubleshooting and faster root cause analysis Low configuration solutions (i.e., less administrative work) and reducing waste.	This is an application health project and hence the alternative is to continue with business requiring IT support for introducing new products and services which can be expensive and time consuming. DO Nothing alternative is not accepted as it will not enable IT to support existing business processes.	Standard market-based and/or commoditized non-core energy workload - deploy in commercial cloud	Proposed solution is built on existing SAP CH Cloud Platform hosted on Azure.	No	1/4/2027	12/31/2028	$ 1,216,341.24	$ 1,082,291.56	$ 177,291.52	$ 765,669.04			$ 141,400.00	$ 134,078.68	$ 25,179.68	$ 108,900.00			$ 87,073.69
317	2027	SAP CH Cloud Applications Health	Sustainment	Shared	Customer-IT	Steve Ambrose	OHMD0002754	Level 3	The recommended solution is to provide the necessary resource capacity and services to apply, test and deploy SAP's releases(s) to the SAP CH cloud platform during 2027 and 2028. This schedule will be based off the vendors release schedule to ensure the platform continues to support the self-service needs of DTE's customers and are currently planned to be rolled out on a quarterly basis. This will provide the necessary labor services to build, test and deploy the planned major upgrades and enhancements in the SAP CH Cloud Platform. This will also provide the necessary sustainment services for achieving the required SLA's on the cloud platform through vendor services contract. By keeping the version of the software up to date DTE will be able to continue to deploy new projects required by business.	Customer: Secured digital channel access Effective personalized customer communication Organization: Reduced call volume via customer self-service AHT (Average call handling time) reduction Improve speed to market Employee: Enabling business to roll-out products and offer services without needing support from IT Improved user interface - dashboard view vs. emailed report Targeted troubleshooting and faster root cause analysis Low configuration solutions (i.e., less administrative work) and reducing waste.	This is an application health project and hence the alternative is to continue with business requiring IT support for introducing new products and services which can be expensive and time consuming. DO Nothing alternative is not accepted as it will not enable IT to support existing business processes.	Standard market-based and/or commoditized non-core energy workload - deploy in commercial cloud	Proposed solution is built on existing SAP CH Cloud Platform hosted on Azure.	No	1/1/2027	12/31/2028	$ 2,144,728.02	$ 1,808,281.30	$ 172,900.76	$ 1,458,418.52			$ 215,782.00	$ 344,447.72	$ 30,784.08	$ 313,663.64			$ 246,380.33
318	2028	SAP CH Cloud Applications Health	Sustainment	Shared	Customer-IT	Steve Ambrose	OHMD0002754	Level 3	The recommended solution is to provide the necessary resource capacity and services to apply, test and deploy SAP's releases(s) to the SAP CH cloud platform during 2027 and 2028. This schedule will be based off the vendors release schedule to ensure the platform continues to support the self-service needs of DTE's customers and are currently planned to be rolled out on a quarterly basis. This will provide the necessary labor services to build, test and deploy the planned major upgrades and enhancements in the SAP CH Cloud Platform. This will also provide the necessary sustainment services for achieving the required SLA's on the cloud platform through vendor services contract. By keeping the version of the software up to date DTE will be able to continue to deploy new projects required by business.	Customer: Secured digital channel access Effective personalized customer communication Organization: Reduced call volume via customer self-service AHT (Average call handling time) reduction Improve speed to market Employee: Enabling business to roll-out products and offer services without needing support from IT Improved user interface - dashboard view vs. emailed report Targeted troubleshooting and faster root cause analysis Low configuration solutions (i.e., less administrative work) and reducing waste.	This is an application health project and hence the alternative is to continue with business requiring IT support for introducing new products and services which can be expensive and time consuming. DO Nothing alternative is not accepted as it will not enable IT to support existing business processes.	Standard market-based and/or commoditized non-core energy workload - deploy in commercial cloud	Proposed solution is built on existing SAP CH Cloud Platform hosted on Azure.	No	1/1/2027	12/31/2028	$ 3,405,265.82	$ 3,123,387.74	$ 168,887.80	$ 2,743,727.94			$ 215,782.00	$ 341,888.18	$ 26,424.44	$ 312,463.74			$ 247,527.84
319	2025	Self Service Mobile Channel Application Health	Sustainment	Shared	Customer-IT	Steve Ambrose	OHMD0002740	Actual	Approved in U-21080																					
320	2026	Self Service Mobile Channel Application Health	Sustainment	Shared	Customer-IT	Steve Ambrose	OHMD0002740	Level 3	Approved in U-21080																					
321	2027	Self Service Mobile Channel Application Health	Sustainment	Shared	Customer-IT	Steve Ambrose	OHMD0002740	Level 3	The DTE Energy mobile applications require regular enhancement to ensure they continue to provide value to customers. A technical team, including developers, testers, and a team lead are required to deliver regular monthly enhancements to the application, as well as support any production issues that should arise. Procure a technical team consisting of development, testing, and project management roles. This team will work with stakeholders to prioritize monthly enhancements, build, test, and deliver them to the Apple app store and Google Play Store through 2025-2027. This team will also provide storm support and production support for any issues that should arise.	Customer Value: Continued used of DTE mobile apps for energy service transactions. Employee Value: The mobile applications will continue to function for our customers, reducing calls for help.	Not Applicable	Mobile Applications run on customer mobile devices	No-	1/2/2025	12/29/2028	$ 1,270,991.73	$ 1,101,579.36	$ 164,656.66	$ 790,712.52			$ 140,207.18	$ 168,502.37	$ 27,764.61	$ 140,737.58			$ 121,995.72
322	2028	Self Service Mobile Channel Application Health	Sustainment	Shared	Customer-IT	Steve Ambrose	OHMD0002740	Level 3	The DTE Energy mobile applications require regular enhancement to ensure they continue to provide value to customers. A technical team, including developers, testers, and a team lead are required to deliver regular monthly enhancements to the application, as well as support any production issues that should arise. Procure a technical team consisting of development, testing, and project management roles. This team will work with stakeholders to prioritize monthly enhancements, build, test, and deliver them to the Apple app store and Google Play Store through 2025-2027. This team will also provide storm support and production support for any issues that should arise.	Customer Value: Continued used of DTE mobile apps for energy service transactions. Employee Value: The mobile applications will continue to function for our customers, reducing calls for help.	Not Applicable	Mobile Applications run on customer mobile devices	No	1/2/2025	12/29/2028	$ 1,269,982.24	$ 1,100,581.11	$ 163,661.84	$ 790,712.44			$ 140,208.98	$ 168,502.13	$ 27,764.61	$ 140,737.32			$ 121,995.54
323	2025	Supporting capabilities Test data and test data mgmt	Sustainment	Shared	Customer-IT	Steve Ambrose	OHMD0001491	Actual	The recommended solution is to use TOSCA which we implemented for regression test. For performance test, the recommendation was to use load runner scripts. In 2024 We are planning to upgrade the current TOSCA version and convert existing scripts to support the new version. There will be 12 regression test execution using TOSCA. There will be minimum of 4 performance test conducted for Error Free Communication using Load Runner scripts. The Web Self-Service projects will undergo performance test at least 3 times in 2024 using Load Runner scripts. In 2025 There will be 12 regression test execution using TOSCA. There will be minimum of 5 performance tests conducted for Error Free Communication using Load Runner scripts. The Web Self-Service projects will undergo performance test at least 4 times using Load Runner scripts.	Increase Quality and Minimize cost and time by generating test data using automating test data generation and regression test process. It also minimizes the defect/error rate as we can provide full coverage to the test use cases by providing test data whenever is required. It also minimizes user error by performing load/performance test before every release	Currently Technical SME's need be involved to manually produce the test data as required for the teams testing. This will include additional effort, time and cost for every request. If this business case is not implemented then we should stay with the status quo and there is no other alternative solution.	Not Applicable	Yes	1/2/2024	12/31/2025	$ 765,918.00	$ 717,114.13	$ 22,019.96	$ 614,981.89	$ 3,077.28	$ 17,800.00	$ 56,425.00	$ 48,803.87		$ 38,423.50	$ 6,800.00	$ 3,790.07	$ 32,176.20
324	2026	Supporting capabilities Test data and test data mgmt	Sustainment	Shared	Customer-IT	Steve Ambrose	OHMD0002717	Level 3	Approved in U-21080																					
325	2027	Supporting capabilities Test data and test data mgmt	Sustainment	Shared	Customer-IT	Steve Ambrose	OHMD0002717	Level 3	The recommended solution is to use TOSCA which we implemented for regression test. For performance test, the recommendation is to use load runner scripts. In 2026 We are planning to upgrade Load Runner version and increase infrastructure sizing to test 2.0M outages. There will be 12 regression test execution using TOSCA. New SAP Cloud initiatives will be scripted for automated testing. Expected to have ~100 scripts. CR&B expects to add ~75 scripts. There will be minimum of 4 performance test conducted for Error Free Communication using Load Runner scripts. The Web Self-Service projects will undergo performance test at least 4 times in 2026 using Load Runner scripts. In 2027 There will be 12 regression test execution using TOSCA. New SAP Cloud initiatives will be scripted for automated testing. Expected to have ~100 scripts. CR&B expects to add ~75 scripts. There will be minimum of 5 performance tests conducted for Error Free Communication using Load Runner scripts. The Web Self-Service projects will undergo performance test at least 4 times using Load Runner scripts.	Increase Quality and Minimize cost and time by generating test data using automating test data generation and regression test process. It also minimizes the defect/error rate as we can provide full coverage to the test use cases by providing test data whenever is required. It also minimizes user error by performing load/performance test before every release	Currently Technical SME's need be involved to manually produce the test data as required for the teams testing. This will include additional effort, time and cost for every request. If this business case is not implemented then we should stay with the status quo and there is no other alternative solution.	Not Applicable	No-	1/2/2026	12/31/2027	$ 550,035.80	$ 500,022.44	$ 49,791.44	$ 396,769.00			$ 53,551.90	$ 50,013.36	$ 1,413.36	$ 41,100.00		$ 7,500.00	$ 36,269.67
326	2028	Supporting capabilities Test data and test data mgmt	Sustainment	Shared	Customer-IT	Steve Ambrose	OHMD0004215	Level 3	Tricentis Tosca A model-based test automation platform providing: End-to-end automated regression testing API, UI, database, and cross application validation Data-driven testing Risk-based testing Reusable components enabling scalable automation Tricentis Tosca Ceragina A centralized configuration and change management system enabling: Version control for test modules, cases, and datasets Impact analysis and change tracking Multi-tenancy for managing enterprise assets Governance and audit-compliant change history Promotion and deployment of test assets across environments Micro Focus LoadRunner A market-leading performance testing tool providing: Simulation of thousands of concurrent users Stress, load, endurance, and scalability testing Broad protocol support (web, API, SAP, Citrix, mobile, etc.) Integration with enterprise monitoring and analytics platforms Tricentis Flood: A cloud-native load testing platform providing:	The sustainment and maintenance of Tricentis Tosca, Tosca Ceragina, and LoadRunner create significant value for the entire organization by improving software quality, accelerating delivery, and ensuring compliance. Automated testing reduces manual effort and human error while boosting reliability and performance, while employees benefit from reduced manual work, better collaboration, and increased productivity. This investment directly supports strategic goals in operational excellence, digital transformation, and customer satisfaction.	Do Nothing will have the impact on the following: Regression cycles become significantly longer and more costly Higher defect leakage and increased production risk No structured performance testing = high risk of outages during peak load Manual testing cannot keep pace with business growth Manual testing cannot scale with business growth	N/A	Yes	1/3/2028	12/31/2028	$ 827,407.64	$ 602,107.64	$ 36,000.04	$ 485,800.04	$ 24,999.96		$ 55,307.00	$ 225,300.00		$ 225,300.00			$ 165,117.20
327	2025	Web Transaction Application Health	Sustainment	Shared	Customer-IT	Steve Ambrose	OHMD0004211	Actual	Approved in U-21080																					
328	2026	Web Transaction Application Health	Sustainment	Shared	Customer-IT	Steve Ambrose	OHMD0004211	Level 3	Approved in U-21080																					

329	2027	Web Transaction Application Health	Sustainment	Shared	Customer IT	Steve Ambrose	OPHD0003977	Level 3	Support the sustainment work to provide capacity for regular minor enhancements, infrastructure patching and upgrades, production monitoring and support, defect resolution. Enhancements will be developed across all the in-scope applications/business transactions, leveraging biweekly sprints, with releases occurring on a regular cadence (e.g. bi-weekly, monthly) over the course of 2027 and 2028. Specific work items will be identified and prioritized each sprint, based on customer value, security, technical criticality. Key metrics that will drive prioritization are Digital Engagement Rate (Csat reduction), Transaction Completion Rate, System Availability, Complaint reduction, vulnerability count, Planned Outage reduction, Unplanned Outage reduction.	Ensures clear and easy to use digital web experiences for customer, allowing them to complete key transactions on the web channel. Reduces cost to the company by ensuring the call reduction targets that were achieved strategically can be maintained.	Drop support and "sweat" the assets. Do Nothing will result in significant regression in our key customer experience metrics: Digital Engagement Rate (Csat reduction), Transaction Completion Rate, System Availability, Complaint reduction, vulnerability count, Planned Outage reduction, Unplanned Outage reduction	Standard market-based and/or commoditized non-core energy workload - deploy in commercial cloud	applications under this sustainment demand were custom-build, cloud-native applications running on a mix of AW	No	1/15/2027	12/15/2028	$ 5,486,154.03	$ 5,067,096.00	$ 614,657.00	$ 3,825,000.00			$ 947,439.00	$ 459,058.00	$ 58,058.00	$ 401,000.00				$ 332,357.99
330	2026	Web Transaction Application Health	Sustainment	Shared	Customer IT	Steve Ambrose	OPHD0003977	Level 3	Support the sustainment work to provide capacity for regular minor enhancements, infrastructure patching and upgrades, production monitoring and support, defect resolution. Enhancements will be developed across all the in-scope applications/business transactions, leveraging biweekly sprints, with releases occurring on a regular cadence (e.g. bi-weekly, monthly) over the course of 2027 and 2028. Specific work items will be identified and prioritized each sprint, based on customer value, security, technical criticality. Key metrics that will drive prioritization are Digital Engagement Rate (Csat reduction), Transaction Completion Rate, System Availability, Complaint reduction, vulnerability count, Planned Outage reduction, Unplanned Outage reduction.	Ensures clear and easy to use digital web experiences for customer, allowing them to complete key transactions on the web channel. Reduces cost to the company by ensuring the call reduction targets that were achieved strategically can be maintained.	Drop support and "sweat" the assets. Do Nothing will result in significant regression in our key customer experience metrics: Digital Engagement Rate (Csat reduction), Transaction Completion Rate, System Availability, Complaint reduction, vulnerability count, Planned Outage reduction, Unplanned Outage reduction	Standard market-based and/or commoditized non-core energy workload - deploy in commercial cloud	applications under this sustainment demand were custom-build, cloud-native applications running on a mix of AW	No	1/15/2027	12/15/2028	$ 5,486,267.00	$ 5,003,844.00	$ 611,405.00	$ 3,825,000.00			$ 947,439.00	$ 456,642.00	$ 57,442.00	$ 399,000.00				$ 330,464.61
331	2027	Cib Portal Migration	Return-to-Health	Shared	Customer IT	Steve Ambrose	OPHD0003976	Level 3	The recommended solution includes a) Re platforming the identified web experiences to a cloud native web experience built using scalable platform services (e.g. AWS CloudFront, AWS ELS, AWS WAF, etc.) and b) conducting an end-to-end evaluation of the customer experience for the given experiences. Final solution architecture will be designed in 2028 as a part of the project. Customers will have an improved experience on our website, including faster load times, increased availability and a reduction in failures/issues. The new experiences on cloud platform will provide the opportunity to more efficiently build additional functionality for customers to engage with digitally. New features will be communicated to customers as they become available. Employees supporting the web experiences will be empowered to more efficiently monitor, operate, and enhance these assets through agile delivery. Employees will also benefit from a reduction in incidents/issues. Customers will also have improved more comprehensive features and information related to their account, primarily account management, with the potential to reduce calls from the Call Center, supporting the Company's goal to achieve first quartile call volume by 2027 (~2.7M calls). Expected improvements are as below: -Reduce page load time from 7s to 4s per page load. - Yearly Planned Outage Duration will be reduced from ~132 hours to ~10 hours. - Overall availability for these functions increased from current of ~98.3% to a target of 99.9%.	Maintaining the Web applications in the existing platform and not migrating them to the Cloud. This is not desirable as the current technology platform is unsupported by the product vendor and upgrading to a newer version is in conflict with the stated cloud application strategy.	Standard market-based and/or commoditized non-core energy workload - deploy in commercial cloud	solution will be built and deployed on cloud-native single page web applications (SPA) on AWS with APIs running in	No	3/4/2027	12/29/2028	$ 4,716,329.00	$ 4,286,329.00		$ 4,050,000.00			$ 216,329.00	$ 450,000.00		$ 450,000.00				$ 325,800.00
332	2028	Cib Portal Migration	Return-to-Health	Shared	Customer IT	Steve Ambrose	OPHD0003976	Level 3	The recommended solution includes a) Re platforming the identified web experiences to a cloud native web experience built using scalable platform services (e.g. AWS CloudFront, AWS ELS, AWS WAF, etc.) and b) conducting an end-to-end evaluation of the customer experience for the given experiences. Final solution architecture will be designed in 2028 as a part of the project. Customers will have an improved experience on our website, including faster load times, increased availability and a reduction in failures/issues. The new experiences on cloud platform will provide the opportunity to more efficiently build additional functionality for customers to engage with digitally. New features will be communicated to customers as they become available. Employees supporting the web experiences will be empowered to more efficiently monitor, operate, and enhance these assets through agile delivery. Employees will also benefit from a reduction in incidents/issues. Customers will also have improved more comprehensive features and information related to their account, primarily account management, with the potential to reduce calls from the Call Center, supporting the Company's goal to achieve first quartile call volume by 2027 (~2.7M calls). Expected improvements are as below: -Reduce page load time from 7s to 4s per page load. - Yearly Planned Outage Duration will be reduced from ~132 hours to ~10 hours. - Overall availability for these functions increased from current of ~98.3% to a target of 99.9%.	Maintaining the Web applications in the existing platform and not migrating them to the Cloud. This is not desirable as the current technology platform is unsupported by the product vendor and upgrading to a newer version is in conflict with the stated cloud application strategy.	Standard market-based and/or commoditized non-core energy workload - deploy in commercial cloud	solution will be built and deployed on cloud-native single page web applications (SPA) on AWS with APIs running in	No	3/4/2027	12/29/2028	$ 4,716,329.00	$ 4,286,329.00		$ 4,050,000.00			$ 216,329.00	$ 450,000.00		$ 450,000.00				$ 325,800.00
333	2025	Digital Channels Transformation Program	Return-to-Health	Shared	Customer IT	Steve Ambrose	OPHD0002742 OPHD0002234	Actual	In 2025 we will modify the separate and distinct Payments and Outage single page applications to become web components that can reside within the architecture that will be established in 2026-2027. The project will design, build and test the current functionality of Guard Pay, Manage Payment Methods, Authorized Payments page to the newer architecture hosted in the new platform. The project will also design, build and test the current functionality of Report Outage, Down Wires, Get Status, Report outage by Police and Fire, Street Lighting to the newer architecture hosted in the new platform. SAP CDC is the single platform hosting all the capabilities required for the above scenarios with native integration to most of the customer service-related assets. After studying the vendor product roadmap, and surveying industry trend, DTE is proposing to upgrade SAP CDC to meet the above requirements. This proposal also aligns with the Architecture recommendations. To implement this initiative, we will need to design, build, test, and deploy the capabilities listed below.	Consolidating our transactional web experiences into a common platform will reduce friction currently felt by customers in their journey though the web channel. A modern transaction platform increases code re-use efficiency, allowing product teams to focus solely on developing their customer journey without the need to recreate boilerplate elements such as headers, footers, and navigation elements. Customers will have multiple login options (one-time passcode, biometrics, and social login) to get authenticated and authorized using the industry standard security arrangements such as SAML, OauthS, etc. Customers will have the ability to update their profile.	Alternatives Considered: Off the shelf solutions and continuing with the current approach of building multiple single page applications. Do Nothing: Without a common foundational architecture, product teams will continue to build separate single page applications for each transaction, driving up costs and increasing customer friction. Third party products for customer identity and access management were evaluated which require custom integration with most of the customer assets. Do nothing is not an option, as it relates to security of the digital channels.	Standard market-based and/or commoditized non-core energy workload - deploy in commercial cloud	oud-native web applications on the AWS and Azure platforms.Proposed solution is built on existing SAP Customer	Yes	1/2/2025	12/31/2025	$ 3,364,598.00	$ 2,900,357.18	$ 171,618.20	$ 2,505,379.12	$ 23,054.71		$ 200,325.00	$ 464,239.15	$ 30,310.64	$ 118,983.45	$ 290.98	$ 254,764.20		$ 271,136.40
334	2026	Digital Channels Transformation Program	Return-to-Health	Shared	Customer IT	Steve Ambrose	OPHD0002786	Level 3	Modify the separate and distinct Payments, Outage, Collections, Registration, and Usage single page applications to become web components that can reside within the architecture that will be established in 2026-2027. 2026: Registration Redesign and Migration to CIAM Platform (Auth0) and integration of customer channels and transactions into CIAM Platform (Auth 0) for login. Provide Customers with additional security and login capabilities, such as MFA, Passkeys, and One Time Passcodes. 2027: Repiatform WCM Content and Forms to AEM. Repiatform remaining transactions including payment locations, rebate status, and document submission portal. 2028: Repiatform WCM and move AWS continued for Commercial Customers.	Consolidating our transactional web experiences into a common platform will reduce friction currently felt by customers in their journey though the web channel. A modern transaction platform increases code re-use efficiency, allowing product teams to focus solely on developing their customer journey without the need to recreate boilerplate elements such as headers, footers, and navigation elements.	Alternatives Considered: Off the shelf solutions and continuing with the current approach of building multiple single page applications. Do Nothing: Without a common foundational architecture, product teams will continue to build separate single page applications for each transaction, driving up costs and increasing customer friction.	Standard market-based and/or commoditized non-core energy workload - deploy in commercial cloud	These solutions are developed as cloud-native web applications on the AWS and Azure platforms.	No	1/2/2026	12/29/2026	$ 5,532,964.64	$ 3,890,483.38	$ 153,215.17	$ 3,566,033.37			$ 81,216.84	$ 1,722,501.96	$ 16,801.52	$ 215,583.04		$ 1,500,000.00		$ 1,254,331.11
335	2027	Digital Channels Transformation Program	Return-to-Health	Shared	Customer IT	Steve Ambrose	OPHD0002786	Level 3	Modify the separate and distinct Payments, Outage, Collections, Registration, and Usage single page applications to become web components that can reside within the architecture that will be established in 2026-2027. 2026: Registration Redesign and Migration to CIAM Platform (Auth0) and integration of customer channels and transactions into CIAM Platform (Auth 0) for login. Provide Customers with additional security and login capabilities, such as MFA, Passkeys, and One Time Passcodes. 2027: Repiatform WCM Content and Forms to AEM. Repiatform remaining transactions including payment locations, rebate status, and document submission portal. 2028: Repiatform WCM and move AWS continued for Commercial Customers.	Consolidating our transactional web experiences into a common platform will reduce friction currently felt by customers in their journey though the web channel. A modern transaction platform increases code re-use efficiency, allowing product teams to focus solely on developing their customer journey without the need to recreate boilerplate elements such as headers, footers, and navigation elements.	Alternatives Considered: Off the shelf solutions and continuing with the current approach of building multiple single page applications. Do Nothing: Without a common foundational architecture, product teams will continue to build separate single page applications for each transaction, driving up costs and increasing customer friction.	Yes - IaaS is Market Based Commodity or Supporting Capability (non-core) and will use public cloud.	These solutions are developed as cloud-native web applications on the AWS and Azure platforms.	No	1/2/2026	12/29/2026	$ 2,531,862.80	$ 2,300,452.46	$ 152,568.00	$ 2,067,066.70			$ 81,216.84	$ 231,130.44	$ 16,116.45	$ 215,000.04				$ 167,358.44
336	2026	Digital Channels Transformation Program	Return-to-Health	Shared	Customer IT	Steve Ambrose	OPHD0002786	Level 3	Modify the separate and distinct Payments, Outage, Collections, Registration, and Usage single page applications to become web components that can reside within the architecture that will be established in 2026-2027. 2026: Registration Redesign and Migration to CIAM Platform (Auth0) and integration of customer channels and transactions into CIAM Platform (Auth 0) for login. Provide Customers with additional security and login capabilities, such as MFA, Passkeys, and One Time Passcodes. 2027: Repiatform WCM Content and Forms to AEM. Repiatform remaining transactions including payment locations, rebate status, and document submission portal. 2028: Repiatform WCM and move AWS continued for Commercial Customers.	Consolidating our transactional web experiences into a common platform will reduce friction currently felt by customers in their journey though the web channel. A modern transaction platform increases code re-use efficiency, allowing product teams to focus solely on developing their customer journey without the need to recreate boilerplate elements such as headers, footers, and navigation elements.	Alternatives Considered: Off the shelf solutions and continuing with the current approach of building multiple single page applications. Do Nothing: Without a common foundational architecture, product teams will continue to build separate single page applications for each transaction, driving up costs and increasing customer friction.	Yes - IaaS is Market Based Commodity or Supporting Capability (non-core) and will use public cloud.	These solutions are developed as cloud-native web applications on the AWS and Azure platforms.	No	1/2/2026	12/29/2026	$ 2,530,868.13	$ 2,301,078.81	$ 151,395.53	$ 2,068,469.38			$ 81,216.79	$ 229,789.32	$ 15,386.45	$ 214,584.92				$ 166,367.47
337	2028	Migrate SAP CRM to SAP S4 HANA	Return-to-Health	Shared	Customer IT	Steve Ambrose	OPHD0002735	Level 2	- - The recommended solution is to migrate the SAP CRM landscape to RISE with SAP through a phased, lift and shift transition approach. Migrates SAP CRM to SAP Customer Experience (C4C), and Migrates SAP IS-U to SAP S/4HANA Utilities, while preserving existing business processes and operational stability during the transition. This approach directly addresses platform risk, aligns the organization to SAP's strategic direction and reduces long term exposure to support, security, and operational risks. Key Deliverables: 1. Lift and Shift Migration of Core Systems SAP CRM and SAP IS-U are considered as core applications that demonstrate the critical path of the S/4HANA program. The recommended solution prioritizes migrating these systems first to ensure business continuity with minimal functional changes. This reduces risk by delay ensuring long term platform viability. 2. Adoption of RISE with SAP Operating Model The solution leverages RISE with SAP to standardize infrastructure, operations, and lifecycle management. This provides a supported, cloud-based operating model aligned to SAP's roadmap, reducing dependencies across CRM, utilities, and customer experience platforms. 3. Preservation of Customer Service and Billing Continuity By avoiding large scale redesign during the initial migration, the solution protects: Day to day customer service operations Billing accuracy and revenue assurance Regulatory and audit confidence This sequencing ensures the business remains focused on service delivery while the technology foundation is modernized. The 2025 EPC project provides funding to address a) Estimate Time of Restoration b) Service Recovery for Frequent outage customers	BENEFIT VALUE TO THE ORGANIZATION The SAP CRM Migration delivers significant enterprise- level value by reducing platform risk and establishing a sustainable SAP foundation for the organization. Reduced Technology and Vendor Risk Migrating SAP CRM and SAP IS-U both classified as core applications ensures the organization remains reliance on aging, increasingly unsupported platforms. This aligns the organization to SAP's strategic direction and reduces long term exposure to support, security, and operational risks. Improved Operational Resilience and Stability Adoption of RISE with SAP provides a standardized, cloud based operating model that improves system reliability, lifecycle management, and platform resilience, enabling the organization to operate with greater confidence as an enterprise transformation progresses. Foundation for Future Value Realization By stabilizing the core SAP landscape first, the organization can then focus on future enhancements—including customer experience modernization, analytics, and process optimization—without compounding risk during the initial migration. Benefit / Value to the Customer For customers, the primary value of the initiative is continuity, trust, and readiness for future improvement. - - - Uninterrupted Customer Service and Billing The lift and shift approach preserves existing CRM and IS-U processes during migration, ensuring customers experience no disruption to billing, account management, or service interactions. This protects customer confidence and satisfaction. Improved Reliability of Customer Facing Systems Operating customer service and billing processes on modern, supported SAP platforms reduces the likelihood of outage or system degradation, improving the overall reliability of customer interactions. Enabler for Enhanced Customer Experience While not immediately changing the customer experience, migrating to SAP C4C and S/4HANA Utilities positions the organization to introduce future enhancements—such as improved digital channels and analytics—once platform stability is achieved. Benefit / Value to Employee	Regulated data or workload - deploy in government or sovereign cloud	ed security obligations This requirement applies to customer, billing, and utility workloads supported by SAP CRM	No	1/3/2028	6/30/2030	$ 17,000,000.00	$ 15,000,000.02	$ 981,354.00	$ 12,987,457.46			$ 1,651,188.12	$ 1,999,999.96	$ 192,351.00	$ 1,807,048.96				$ 1,447,999.97
338	2025	Migrate SAP Marketing Cloud to SAP DYNAMYS	Return-to-Health	Shared	Customer IT	Steve Ambrose	OPHD0002827	Actual	In alignment with vendor product roadmap DTE has to migrate marketing capabilities to SAP DYNAMYS from SAP Marketing cloud which will go out of support from 2026. As part of this initiative, the new SAP DYNAMYS tenant will be setup, configured and integrated with other On-Prem applications (provided the list under what business system or process is being affected section) SAP DYNAMYS has enhanced marketing capabilities hence the existing marketing to sales processes need to be redesigned, adopting the enhanced capabilities. It will improve the Scalability of marketing spend, Omnichannel marketing experience and personalized marketing for customers. Consolidate tools: Use an integrated marketing platform that combines various tools into one system. Centralized data store and governance: Central repository of customer data - 360 view for better insights and enforcing policies As part of this initiative, we will implement SAP CDP to support data requirement for the SAP DYNAMYS platform We are reducing the below scope items: Automate Tasks: Utilize automation for repetitive tasks like email marketing, social media posting, and data analysis. This saves time and reduces errors. Optimize Costs: Marketing activities managed through a single platform, help reduce the duplication of efforts and operational costs The built in predictive analytics using Artificial Intelligence (AI) can enable DTE to send marketing campaigns to a focused audience Personalize customer communications across multiple channels (SMS, Voice, Social, etc.)	Business can continue to use the cloud application for marketing and customer engagement through communications. More efficient marketing campaigns, improved marketing analytics for performance. Personalized communication and marketing, identification of customer preferred window of communication. Ability to track the customer interest with DTE to recommend the products and services offered by DTE. To drive more revenue and more value to customers Accelerate time to value with product analytics & use cases Deliver the 1:1 personalization across all channels increasing customer retention and loyalty	DYNAMYS has standard integrations with rest of the applications within the landscape, hence no other products have been analyzed. A do nothing approach will result in operating on non-supported versions of the platform software which will result in increased risk of the platform becoming inoperable.	Standard market-based and/or commoditized non-core energy workload - deploy in commercial cloud	Proposed solution is built on existing SAP Customer Cloud Platform hosted on Azure.	Yes	2/3/2025	11/30/2025	$ 1,203,386.00	$ 1,038,808.85	$ 37,644.00	$ 940,017.24	$ 4,755.61		$ 58,443.00	$ 164,577.45	$ 51,942.25	$ 67,550.55	$ 0.22	$ 45,084.47		$ 109,719.16
339	2027	SAP Commerce B2C Storefront Migration	Return-to-Health	Shared	Customer IT	Steve Ambrose	OPHD0003064	Level 3	In alignment with vendor product roadmap DTE has to migrate commerce capabilities to SAP Commerce Cloud platform. The recommended solution is to unify the B2C and B2B storefronts. By unifying these storefronts, deployment of any new products or services for B2B and B2C customers will be quicker and less expensive. Integration with ADPI heavily reduces the time to design, build and transfer new digital content from ADPI to SAP commerce, thereby reducing the cost of implementing or changing products and services. Unification of the storefronts reduce the need for multiple skillsets to just one skillset. To implement this initiative, we will need to design, build, test, and deploy the new product in SAP commerce. The unified storefront also reduces the periodic commerce upgrade initiative to be in alignment with vendor's product release schedule.	Business can take advantage of the headless commerce platform to create/change the product offerings with no dependency on backend application. Employees do not need multiple skillsets to maintain the 2 digital storefronts. Readily adopt new capabilities released by product vendor. Improved customer experience, faster page refresh and improved search engine optimization, are some of the key advantages to the customers.	Other alternatives considered are 3rd party solutions which do not align with DTE architecture principles, that requires multiple custom integrations, which makes maintenance very costly and difficult.	Standard market-based and/or commoditized non-core energy workload - deploy in commercial cloud	Proposed solution is built on existing SAP Customer Cloud Platform hosted on Azure.	Yes	3/4/2027	12/31/2027	$ 1,779,285.77	$ 1,598,758.79	$ 216,865.70	$ 1,482,802.00	$ 20,009.00	$ 109,000.00	$ 274,073.00	$ 185,548.08	$ 43,546.00	$ 137,000.00				$ 139,750.01
340	2027	Web Billing and Profile Management Cloud Migration	Return-to-Health	Shared	Customer IT	Steve Ambrose	OPHD0002879	Level 3	The recommended solution includes a) Re platforming the identified web experiences to a cloud native web experience built using scalable platform services (e.g. AWS CloudFront, AWS ELS, AWS WAF, etc.) and b) conducting an end-to-end evaluation of the customer experience for the given experiences. The company executed a proof-of-concept activities in 2024 to confirm the viable technical solutions. Preliminary discovery and benchmarking were completed in Q4 2024, primarily focusing on the "current bill" page. Final solution architecture will be designed in 2026 as a part of the project. Customers will have an improved experience on our website, including faster load times, increased availability and a reduction in failures/issues. The new experiences on cloud platform will provide the opportunity to more efficiently build additional functionality for customers to engage with digitally. New features will be communicated to customers as they become available. Employees supporting the web experiences will be empowered to more efficiently monitor, operate, and enhance these assets through agile delivery. Employees will also benefit from a reduction in incidents/issues. Customers will also have improved more comprehensive features and information related to their account, primarily their billing experience, with the potential to reduce 3-5% of calls from the Call Center, supporting the Company's goal to achieve first quartile call volume by 2027 (~2.7M calls). Expected improvements are as below: Reduce page load time from 7s to 4s per page load. Yearly Planned Outage Duration will be reduced from ~132 hours to ~10 hours. Overall availability for these functions increased from current of ~98.3% to a target of 99.9%.	Maintaining the Web applications in the existing platform and not migrating them to the Cloud. This is not desirable as the current technology platform is unsupported by the product vendor and upgrading to a newer version is in conflict with the stated cloud application strategy.	Standard market-based and/or commoditized non-core energy workload - deploy in commercial cloud	The solution will be built and deployed as cloud-native web applications on AWS with APIs running in Azure.	No	1/5/2027	12/31/2028	$ 5,017,305.12	$ 4,559,549.47	$ 464,536.43	$ 3,508,469.04			$ 556,113.00	$ 458,255.65	$ 108,455.65	$ 269,800.00				$ 331,777.09
341	2028	Web Billing and Profile Management Cloud Migration	Return-to-Health	Shared	Customer IT	Steve Ambrose	OPHD0002879	Level 3	The recommended solution includes a) Re platforming the identified web experiences to a cloud native web experience built using scalable platform services (e.g. AWS CloudFront, AWS ELS, AWS WAF, etc.) and b) conducting an end-to-end evaluation of the customer experience for the given experiences The company executed a proof-of-concept activities in 2024 to confirm the viable technical solutions. Preliminary discovery and benchmarking were completed in Q4 2024, primarily focusing on the "current bill" page. Final solution architecture will be designed in 2026 as a part of the project. Customers will have an improved experience on our website, including faster load times, increased availability and a reduction in failures/issues. The new experiences on cloud platform will provide the opportunity to more efficiently build additional functionality for customers to engage with digitally. New features will be communicated to customers as they become available. Employees supporting the web experiences will be empowered to more efficiently monitor, operate, and enhance these assets through agile delivery. Employees will also benefit from a reduction in incidents/issues. Customers will also have improved more comprehensive features and information related to their account, primarily their billing experience, with the potential to reduce 3-5% of calls from the Call Center, supporting the Company's goal to achieve first quartile call volume by 2027 (~2.7M calls). Expected improvements are as below: Reduce page load time from 7s to 4s per page load. Yearly Planned Outage Duration will be reduced from ~132 hours to ~10 hours. Overall availability for these functions increased from current of ~98.3% to a target of 99.9%.	Maintaining the Web applications in the existing platform and not migrating them to the Cloud. This is not desirable as the current technology platform is unsupported by the product vendor and upgrading to a newer version is in conflict with the stated cloud application strategy.	Standard market-based and/or commoditized non-core energy workload - deploy in commercial cloud	The solution will be built and deployed as cloud-native web applications on AWS with APIs running in Azure.	No	1/5/2027	12/31/2028	$ 4,858,245.63	$ 4,591,131.33	$ 494,292.96	$ 3,452,869.04			$ 553,228.99	$ 458,114.19	$ 107,914.20	$ 270,200.00				$ 331,674.98
342	2025	Outage MSPO, PPS, and Map Enhancement	IT Enhancements	Electric	Customer IT	Steve Ambrose	OPHD0003913	Actual	The Error Free Communication (EFC) Program which comprises of Outage MSPO, PPS, Outage Map, Notifications and Digital Channels Enhancements, is a multi-year effort to address the root cause of customer dissatisfaction with the quality of communication they received such as inaccurate status of their meter condition (e.g., channels are reporting to them that they are restored when they are not), and unreliable estimates for when they can expect to be restored. This lack of accuracy is impacting our customers' trust in DTE during these high volume events. Customers are not satisfied with their current outage communication experience across all channels. They want accurate, meaningful and timely restoration updates. In order to achieve the vision of error free communication, we need to address the root cause of customer dissatisfaction with current designs and information presentation. Our digital channels and proactive messaging systems will need to be updated and redesigned to meet our new and improved outage communication strategy that will meet our customer's needs. The proposed solution provides the following functionality/capabilities: The 2025 EFC project provides funding to address a) Estimate Time of Restoration b) Service Recovery for Frequent outage customers	The proposed solution provides confidence every customer is accounted for, accurate data for outage communications, consistent data to all endpoints and accurate restoration times. Specific scope will be based on where we stand as of 2024 and what is needed to reach our long-term targets and customer and MPSC expectations. Restoration Communication Accuracy & Timeliness. Long-Term Target – To maintain a Power Restoration Accuracy of 98% and improve timeliness to identify the customer's power status to within 15 minutes or less. Outage Notification Delivery. Long-Term Target – The Company is targeting to increase the percent of customers with reported outages successfully receiving outage status notifications to 98%. First Estimate Accuracy. Long-Term Target – The Company is targeting 98% First Estimate Accuracy during all storms, to be delivered to the customer within 4 hours of the customer's power loss. Outage Digital Completion Rate Targets 2024: 60%, 2027: Aspiration: 97% Digital Engagement Rate Targets 2024: 34%, 2027:Aspiration: 98%.	A "do nothing" alternative would result in gaps in outage management requirements and could result in unanticipated customer experience.	Standard market-based and/or commoditized non-core energy workload - deploy in commercial cloud	Because Customer Applications and Customer Data is non-core and hosted in public cloud	Yes	1/6/2025	12/17/2025	$ 578,881.00	$ 578,881.00		$ 540,000.00	$ 2,700.00		$ 36,183.00	$ -	$ -	$ -				$ -
343	2025	Payment Merchant Fees	Strategic	Shared	Customer IT	Steve Ambrose	OPHD0003774	Actual	To address DTE's merchant fee challenge, the recommended solution is to partner with a third-party consumer payment provider, such as Paymentus, Speedpay, BillPostXs, or Kubra. These providers will handle credit card fee processing, offer Visa consulting support, and assist in developing DTE's long term payment strategy to ensure seamless bill payment options for customers. Currently, all utility companies that charge credit card fees use one of these third-party solutions, which differs from DTE's existing payment handling approach. Implementing this solution will require DTE to: Integrate its payment systems and channels with a third-party consumer payment solution. Develop and execute a comprehensive merchant fee strategy.	Customer: Improved payment experience on self-serve channels, however, this will not offset customer dissatisfaction of paying card fees. Employee: No immediate improvement to employee experience, however, opportunities to improve with enhanced agent tools available by third-party payment consumer solution.	A customized solution primarily developed by DTE to manage merchant fees was considered but ultimately not recommended. A customized solution with our current payment processor, Paymentis, does not support flat fee models and would require DTE to integrate with another third-party provider to determine surcharge percent based on the card type and billing zip code. Do nothing, the Company would incur ~$8M in merchant fee costs per year to the company.	Standard market-based and/or commoditized non-core energy workload - deploy in commercial cloud	Final solution design is in progress and will align with cloud delivery strategy.	Yes	1/5/2025	12/31/2025	$ 9,758,300.00	$ 9,471,496.10	$ 672,758.24	$ 7,042,287.88	$ 39,732.17	$ 17,280.00	$ 796,596.00	$ 286,843.87	$ 121,384.59	$ 165,539.39	$ 650.13			$ 207,474.94
344	2026	Payment Merchant Fees - Phase 2	Strategic	Shared	Customer IT	Steve Ambrose	OPHD0003985	Level 3	The recommended solution is to implement Paymentus solution and they will handle merchant fees at their side. Self-Service, Interactive Voice Response, and Customer Service Representative channels will be impacted. These providers will handle credit card fee processing, offer Visa consulting support, and assist in developing DTE's long term payment strategy to ensure seamless bill payment options for customers.	Customer: Improved payment experience on self-serve channels, however, this will not offset customer dissatisfaction of paying card fees. Employee: No immediate improvement to employee experience, however, opportunities to improve with enhanced agent tools available by third-party payment consumer solution.	A customized solution primarily developed by DTE to manage merchant fees was considered but ultimately not recommended. A customized solution with our current payment processor, Paymentis, does not support flat fee models and would require DTE to integrate with another third-party provider to determine surcharge percent based on the card type and billing zip code. Stuadio: remove ability for customers to use cards - would result in significant negative impact to customer satisfaction, self-serve usage and un-collectable revenue (UCR). Do nothing, the Company would incur ~$8M in merchant fee costs per year to the company.	Standard market-based and/or commoditized non-core energy workload - deploy in commercial cloud	Paymentus is aligned with cloud delivery strategy.	No	1/5/2026	7/31/2026	$ 6,930,837.76	$ 5,000,448.21	$ 263,975.21	$ 4,535,509.00			$ 400,973.00	$ 1,500,389.97	$ 1,279,889.57	$ 221,500.00				$ 1,084,282.06

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-22046
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS

AND

REVISED DIRECT TESTIMONY

OF

JASON D. DE STIGTER

DTE ELECTRIC COMPANY
QUALIFICATIONS AND REVISED DIRECT TESTIMONY OF J. DE STIGTER

Line No.

1 **Background & Qualifications**

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

3 A1. My name is Jason D. De Stigter. My business address is 9400 Ward Parkway, Kansas City,
4 Missouri 64114. I am employed by 1898 & Co. as the Director of Utility Investment
5 Planning in our Utility Consulting Practice.

6

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

8 A2. I am testifying on behalf of DTE Electric Company (DTE Electric or Company).

9

10 **Q3. Please generally describe the work of 1898 & Co.**

11 A3. 1898 & Co. was established in 2019 as the consulting division of Burns & McDonnell
12 Engineering Company, Inc. ("Burns & McDonnell"). 1898 & Co. is a nationwide network
13 of over 600 consulting professionals serving the Manufacturing & Industrial, Oil & Gas,
14 Power Generation, Transmission & Distribution ("T&D"), Transportation, and Water
15 industries.

16

17 Burns & McDonnell was established in 1898 and serves multiple industries, including the
18 electric power industry. Burns & McDonnell is a family of companies comprising more
19 than 13,000 engineers, architects, construction professionals, scientists, consultants, and
20 entrepreneurs, with more than 75 offices across the country and throughout the world.

21

22 **Q4. Please describe your educational background and professional experience.**

23 A4. I received a Bachelor of Science degree in Engineering and a Bachelor of Business
24 Administration degree from Dordt College, now called Dordt University. Prior to joining
25 1898 & Co. and Burns & McDonnell, I served as a Principal Consultant at Black & Veatch

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in their Asset Management Practice, where I performed risk and resiliency studies. I am a registered Professional Engineer in the State of Kansas. My full resume is attached hereto as Exhibit A-28 Schedule R1.

I am a professional engineer with 18 years' experience providing consulting services to electric utilities. Through my work at 1898 & Co. and Burns & McDonnell, I have developed extensive experience in asset management, capital planning and optimization, risk/resiliency assessments and analysis, asset failure analysis, and business-case development for electric utilities. I have been involved in numerous studies modeling risk for utility clients, including economic analyses for several multi-billion-dollar capital projects and large utility systems. In my role as a Director of Utility Investment Planning, I have worked on and overseen risk and resiliency consulting studies on a variety of electric T&D assets. I have a focus on developing risk and resiliency-based investment models for large capital projects/programs.

Q5. Have you previously sponsored testimony before the Michigan Public Service Commission (MPSC or Commission)?

A5. Yes, I previously sponsored testimony for the benefit cost analysis in Case No. U-21860. A complete list of testimonies I have provided before other regulatory bodies is included with Exhibit A-28 Schedule R1.

<u>Purpose & Overview</u>

Q6. What is the purpose of your direct testimony?

A6. DTE Electric engaged 1898 & Co. to perform a benefit cost analysis (BCA) for the following investment programs included within this rate case filing:

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1. Pole and Pole-Top Maintenance & Modernization (PTMM)
2. Small Wire Replacement Program
3. Underground Residential Distribution (URD) Replacement Program
4. Cable Replacement Program
5. Breaker Replacement Program
6. Subtransmission SCADA
7. Distribution Automation (DA)
8. Communication Network
9. Subtransmission Redesign and Rebuild
10. 4.8 kV and 8.3 kV Conversion

The purpose of my testimony is to explain and support the benefit cost analyses performed by 1898 & Co. for selected DTE Electric investment programs included in this case. Specifically, my testimony:

- Part I: Provides an overview of the key updates from the 2025 to 2026 BCA performed by 1898 & Co.
- Part II: Outlines the approach employed by 1898 & Co. to perform the BCA for the programs listed above.
- Part III: Summarizes the BCA results for each program.
- Part IV: Provides my conclusions.

My direct testimony also introduces, summarizes, and incorporates by reference the Program BCA Report developed as part of that effort.

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Q7. Are you sponsoring any exhibits in this proceeding?

A7. Yes. I am sponsoring the following exhibits:

Exhibit	Schedule	Description
A-28	R1	Resume of Jason D. De Stigter with – List of Prior Regulatory Testimony
A-28	R2	Integrated Resilience, Reliability, & Risk – Investment Model
A-28	R3 Revised	Program Benefit Cost Analysis Report 2026

Q8. Was your testimony and these exhibits prepared by you or under your direction?

A8. Yes, they were.

Q9. Please describe your involvement in performing the benefit-cost analysis for the various programs.

A9. I served as the 1898 & Co. project director for the DTE Electric BCA performed at my direction by 1898 & Co. In that role, I worked directly with DTE Electric's team in the development and justification of the benefit-cost analysis. Specifically, I was responsible for the overall 1898 & Co. engagement and involved in the creation and direction of the development of each benefit cost analysis. I was also directly involved in developing the Integrated Resilience, Reliability, and Risk Investment model that was utilized to perform the BCA.

Q10. What were 1898 & Co.'s objectives for the BCA?

A10. The objectives for the BCA were to:

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1. Quantify the improvement expected for individual DTE Electric investment activities and programs, specifically estimating benefits from a customer centric perspective, mainly avoided future costs to repair or replace assets and value of reduction in customer outages;
2. Demonstrate the expected improvement in the number and duration of customer outages for certain DTE Electric distribution programs;
3. Where applicable, evaluate the DTE Electric system comprehensively and consistently to identify individual investments that are expected to provide the most benefit for customers; and
4. Identify the DTE Electric distribution investments with the highest quantified benefit per dollar invested into the DTE Electric system.

Additionally, a key enhancement in the 2026 BCA is the expanded evaluation of system resiliency, particularly with respect to major weather events that drive a significant portion of customer outages. The analysis incorporates an expanded resilience modeling framework that utilizes historical National Oceanic and Atmospheric Administration (NOAA) storm data, DTE Electric outage records, and Monte Carlo simulation techniques to estimate the frequency, severity, and impact of high-consequence events. This means that the BCA can capture the avoided costs associated with storm-related outages, including both customer outage impacts (Customer Minutes Interrupted or CMI) and restoration costs.

Q11. How does the BCA achieve these objectives?

A11. To achieve these objectives, 1898 & Co. utilized a resilience, reliability, and risk-based planning approach using 1898 & Co.'s proprietary Integrated Resilience, Reliability, and

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Risk Investment Model. The model employs a data-driven decision-making methodology utilizing sophisticated algorithms to calculate the resilience, reliability, and risk mitigation benefit of investments by identifying the expected range of reduced duration and frequency of customer outages, measured as Customer Minutes Interrupted (CMI), and reduced outage restoration costs. The benefit cost approach and model utilized by 1898 & Co. facilitates the identification of distribution investments that provide the most benefit to DTE Electric's customers. Prioritizing and optimizing investments in the electric delivery system helps provide confidence that the overall investment level is appropriate and that customers will get the most value for the level of investment.

Part I: Key Updates from the 2025 to 2026 Benefit-Cost Analysis

Q12. Can you provide an overview of the key updates to the BCA from 2025 to 2026?

A12. Yes, the 2026 BCA differs from the 2025 BCA in several important respects. Most significantly, the 2026 BCA expands the scope of the analysis from three programs and two pilots evaluated in 2025 to a broad portfolio of ten programs spanning distribution, subtransmission, substation, and communications assets. In addition, the 2026 BCA reflects substantial methodological enhancements. These include:

1) Leveraging a resilience modeling framework that uses NOAA event data, outage records, and Monte Carlo simulation to evaluate the impact of major weather events on DTE Electric's system from a CMI and reactive cost perspective
2) Utilizing an updated PTMM inspection reject-rate results
3) Transitioning from Interruption Cost Estimate (ICE) 1.0 to ICE 2.0 for monetizing customer outage impacts
4) Organizing the integrated sequencing of program benefits where the assumption is that vegetation management benefits are considered before the PTMM program occurs and

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vegetation management and PTMM benefits are considered before Distribution Automation (DA) benefits are calculated.

5) Adjusting the approach to the Grid Automation Telecommunications BCA. In the 2026 BCA, the approach is a more direct least-cost comparison between two primary long-term alternatives: public cellular and private cellular supported by fiber backhaul. The BCA is now referred to as the Communication Network Program with the Grid Automation component referring to the fiber optic network build out and the Last-Mile Communications referring to the cellular network build out for edge devices.

As a minor update, DTE Electric provided updated unit cost information for the PTMM and DA investments. The following set of questions include additional details on each major change. I address the inclusion of the resilience modeling framework further below in my testimony. The following questions provide more details on each of the other methodological enhancements.

Q13. What changed with the PTMM pole and pole top reject rate analysis?

A13. In the 2026 analysis, 1898 & Co. used updated and recent inspection results provided by DTE Electric, as described by Company Witness Robinson. These most recent inspection results incorporate updated inspection standards and processes to better reflect the condition and characteristics of individual assets. Utilizing this new rejection data, 1898 & Co. performed a reject rate analysis to understand the expected pole groundline and pole-top inspection failures rates.

For the groundline inspection analysis, the 2026 analysis further refined the reject-rate modeling by using logistic regression and by incorporating pole age and wood type as key

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predictors of failure. The analysis also identified that pine poles installed during the period with higher use of Cellon treatment had elevated reject rates, and that factor was explicitly incorporated into the modeling.

For the pole-top analysis, the more recent inspection results did not include direct pole-top age data, so 1898 & Co. used the age of the associated pole as the basis for estimating pole-top reject rates and developed a three-part failure profile based on the associated pole's installation period.

Exhibit A-28 Schedule R3 Revised includes further details on how this analysis was performed and the resulting reject rates curves utilized in the evaluation for PTMM.

Q14. What is the difference between ICE calculator 1.0 and 2.0?

A14. ICE Calculator 2.0 is an updated version of the interruption cost estimation tool used to monetize customer outage impacts. The 2025 BCA used the ICE 1.0 calculator, which was based on customer interruption surveys conducted from 1989 through 2012 across 15 independent survey efforts in 10 utility service territories. ICE 2.0, by contrast, was released in 2025 as part of a coordinated national update effort and uses more recent survey data collected from 2022 through 2024 across 24 utility service territories in Phase 1. The 2.0 version uses standardized survey methods, consistent data collection, improved econometric modeling, updated customer damage functions, and expanded customer variables such as backup generation and work-from-home prevalence and is adjusted for updates in how society uses energy.

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1 ICE 1.0 used three customer damage function models - residential, small non-residential,
2 and medium/large non-residential - whereas ICE 2.0 uses an updated residential and a
3 unified non-residential customer damage function that evaluates interruption costs using
4 the annual kWh for non-residential customers. Stated simply, ICE 2.0 is intended to
5 provide a more modern, more statistically robust, and more nationally representative
6 estimate of the cost of service interruption than ICE 1.0.
7
8 ICE 2.0 is also being released in phases as additional survey data and utility service areas
9 are incorporated. At the time that this BCA was compiled only Phase 1 of ICE 2.0 was
10 available. Information about the next phase, known as ICE 2.2, was provided on February
11 26, 2026.[1] While phase 2 was released before the filing of this application, the release
12 timing of late February 2026 was too late to incorporate into the Benefit-Cost Analysis.
13 The ICE 2.2 will incorporate additional survey information and updates customer damage
14 functions, which means the interruption cost values will continue to evolve as the phased
15 rollout progresses.
16
17 **Q15. Can you summarize the impacts to the cost of interruptions for customers with the**
18 **ICE 2.0 model?**
19 A15. The use of ICE 2.0 changed the monetized value of service interruption for residential and
20 non-residential customers. For residential customers, ICE 2.0 generally produces a lower
21 value than ICE 1.0 for shorter-duration outages, particularly those under approximately 90
22 minutes, but generally produces a higher value for longer-duration residential outages. In
23 aggregate the values are not meaningfully different.

[1] Currently, the Phase 2 release only includes the average value for C&I customers in Michigan. As part of 1898 & Co.'s evaluation, ICE 2.0 - the Phase 1 release, was done for 20 different customer cohorts. Since only the average value for ICE 2.2 is currently available, 1898 & Co. cannot extract the updated ICE 2.2 values for each of the 20 cohorts.

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For non-residential customers, the change is more significant. The cost of service interruption for non-residential customers is generally comparable for shorter-duration outages. For longer duration outages lasting 10 hours or more, ICE 2.0 values the cost of interruption 50% to 75% lower than ICE 1.0.

To understand the impact of ICE 2.0 on the value of interruption costs for DTE Electric's non-residential customers, 1898 & Co. collected annual kWh usage data for commercial and industrial customers and performed a clustering analysis to group those customers into representative usage bins. Using DTE Electric's non-residential customer profile, 1898 & Co. then compared the estimated cost of interruption under ICE 1.0 and ICE 2.0. From this analysis 1898 & Co. observed that the cost of interruption under ICE 2.0 was approximately 18% lower for 60-minute outages, 68% lower for 720-minute outages, and 57% lower for 1,440-minute outages, as compared to ICE 1.0. In general, this change reduced the monetized outage benefits available in the 2026 BCA, particularly for programs such as DA that derives a substantial portion of benefits from avoided customer outage costs.

Q16. How is ICE 2.2 different from ICE 2.0?

A16. The impact of the change from ICE 2.0 to ICE 2.2 for residential customers show a minor decrease (ICE 2.2. is approximately 2 percent lower than ICE 2.0) while the C&I customers change is notable. For DTE Electric's system, ICE 2.2 is approximately 50 percent higher than ICE 2.0 for outage durations less than 480 minutes. For longer duration outages, over 24 hours, ICE 2.2 is approximately 25 percent higher than ICE 2.0. This demonstrates that the phase 2 release (ICE 2.2) would have a significant impact on the value of outages in the analysis. For many programs the key benefit stream is avoided customer outages. Based

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on this information, 1898 & Co. considers the BCA results to be conservative, especially for programs where the benefits are mainly avoided customer outages and focused on circuit backbones where these C&I customers typically are served from. As a result of these changes, it is expected that the use of ICE 2.2 would increase the monetized outage benefits for programs such as DA, that rely on avoided customer outages, relative to the results calculated using ICE 2.0.

Q17. Please describe the order of modeling operations used as part of an integrated BCA?

A17. The order of modeling operations was used to reflect how multiple programs affect the same portions of the electric system and to avoid double-counting benefits. Because several investment programs can influence the same outage events, 1898 & Co. did not evaluate each program in isolation. Instead, the integrated modeling framework applies the programs in a defined sequence so that the benefits attributed to each program reflect only the incremental value remaining after the effects of earlier programs are considered.

Under that order of operations, the modeling first accounts for the effects of vegetation management, then evaluates PTMM, and then evaluates DA. This sequence is important because vegetation management, PTMM, and DA can each reduce outage impacts on the same circuits, but they do so in different ways. Vegetation management reduces the likelihood of certain vegetation-related outages, PTMM reduces failures associated with aging pole and pole-top infrastructure, and DA reduces the number of customers affected and the duration of outages when faults occur.

In the integrated BCA, the PTMM analysis is performed on a baseline that already reflects the expected effect of vegetation management. Similarly, the DA analysis is performed on

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a baseline that already reflects the expected effects of both vegetation management and PTMM. As a result, the benefits calculated for DA represent the incremental benefits remaining after those preceding investments are taken into account. This sequencing makes the integrated analysis more conservative and provides greater confidence that the quantified benefits are not overstated.

Q18. How did the approach to the Grid Automation Telecommunications BCA change?

A18. The approach to the Grid Automation Telecommunications BCA changed in response to DTE Electric's evolved communication network strategy, detailed in Part V in Witness Rademacher's testimony and Witness Sharma's testimony.

In the 2026 BCA, the approach was refined into a more direct least-cost comparison between two primary long-term alternatives: public cellular and private cellular supported by fiber backhaul. The updated analysis focuses on which of those two alternatives provides the lower life-cycle cost under a range of device-growth assumptions, specifically High, Likely, and Low growth cases that were provided by DTE Electric. In addition, the 2026 BCA excludes DA program benefits from the communications evaluation so that the analysis isolates communication-network-related costs and avoided costs.

As a result, the 2026 approach is more focused on the communications network as an enabling investment and measures its value principally through avoided life-cycle costs relative to the public cellular alternative. The evaluation similarly considers the BCA of specific fiber routes based on the global evaluation.

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Additionally, the project name has been updated in the 2026 BCA. The overall program is now referred to as the Communication Network program with the Grid Automation Telecommunications portion of the program pertaining to the fiber optic build and the Last-Mile Communications portion of the program which pertains to the Cellular network buildout and edge devices.

Part II: Resilience, Reliability, & Risk-Based Planning Approach

Q19. Can you provide a brief overview of the resiliency, reliability, and risk-based planning approach?

A19. 1898 & Co. utilized a resilience, reliability, and risk-based planning approach to identify, prioritize, and perform a benefit-cost analysis to support the investment justification for many of the DTE Electric distribution investment programs outlined above. This approach incorporates historical data, sophisticated algorithms, and a suite of analytics models inside the Integrated Resilience, Reliability, and Risk Investment Model to estimate the Resilience, Reliability, and Risk benefit cost ratio (BCR) for each potential DTE Electric distribution investment activity. The Integrated Resilience, Reliability, and Risk Investment Model is a proprietary model built by 1898 & Co. Benefits are estimated from a customer perspective and shown in terms of the: (1) the decrease in the frequency and impact of customer outages, calculated as CMI; (2) monetization of the decrease in CMI utilizing the U.S. Department of Energy (DOE) ICE Calculator 2.0; and (3) decrease in restoration costs.

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Q20. Outside of last year's DTE Electric rate case filing (U-21860), has 1898 & Co. utilized this approach and model in other regulatory filings?

A20. Yes, 1898 & Co. has utilized this same planning approach and corresponding model in several other states and regulatory jurisdictions. Exhibit A-28 Schedule R1 includes details on each of these cases with links to the various dockets. In summary, 1898 & Co. has utilized this planning approach and corresponding model across eight jurisdictions and 13 utility operating companies. In seven of these jurisdictions, over $7 billion of T&D investment has been approved by commissions or settled upon by intervening parties. Each of the cases utilized the modeling results for prudence evaluation.

Q21. Were all the programs evaluated in the Integrated Resilience, Reliability, and Risk Investment Model?

A21. No. Seven of the ten programs outlined above were evaluated completely within the Integrated Resilience, Reliability, and Risk Investment model. The Subtransmission Redesign and Rebuild and 4.8 kV and 8.3 kV Conversion projects used this integrated model to evaluate project benefits, while project scoping and cost estimation were developed through a separate project-specific process conducted in collaboration with DTE Electric. These projects were defined by DTE Electric and include larger and more complex projects with a wide range of asset classes. Additionally, 1898 & Co. reflected the portion of the project that has already been completed. The Communication Network program was evaluated using a similar model to the one employed in 2025. The table below provides an overview of the modeling employed by program. The programs listed as "Custom BCA" are programs that were not evaluated entirely in the Integrated Resilience, Reliability, and Risk Investment model.

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1 **Table 1 Overview of Modeling Employed By Program**

Programs	Analytic Model Used
Pole and Pole Top Maintenance & Modernization (PTMM)	Resilience Event Simulation and Equipment Failure Mitigation Model
Small Wire Replacement Program	Resilience Event Simulation and Equipment Failure Mitigation Model
URD Replacement Program	Equipment Failure Mitigation Model
Cable Replacement	Equipment Failure Mitigation Model
Breaker Replacement Program	Equipment Failure Mitigation Model
Subtransmission SCADA	Resilience Event Simulation
Distribution Automation (DA)	Outage Mitigation Model
Communication Network	Custom BCA
Subtransmission Redesign and Rebuild	Resilience Event Simulation and Equipment Failure Mitigation Model for benefits
4.8 kV & 8.3 kV Conversion Program	Resilience Event Simulation, and Equipment Failure Mitigation Model for benefits

2

3 **Q22. Have any of these commissions publicly commented on the 1898 & Co. Resilience,**
4 **Reliability, and Risk investment planning process and model?**

5 A22. Yes, the Public Utility Commission of Texas has utilized 1898 & Co. modeling approach
6 and model to approve over $4 billion of System Resiliency Plans (SRP) for three different
7 utilities: Oncor, Entergy Texas, and Texas-New Mexico Power (TNMP). These are
8 currently the only plans the commission has approved. Four other SRPs are pending
9 approval, two of which 1898 & Co. supported and performed the benefit cost evaluation.
10 At the first open hearing meeting, October 24, 2024, to discuss the first system resiliency
11 plan for Oncor, Commissioner Jimmy Glotfelty, said the following about 1898 and Co.'s
12 analytic model: "First I want to say, coming right out of the box, I was impressed with the
13 analytics behind what 1898 [and Co.] put together.....but the fact that they are steeped in
14 utilizing data and models to help solve and slice and dice the data to figure out where to go
15 and what to do I think is a valuable tool." ("Open Meeting at 9:30 AM October 24th ,"

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01:32:12-1:32:45)[2] At the following open hearing meeting on November 14th, 2024, Commissioner Glotfelty reiterated his support of 1898 and Co.'s analytic model saying: "I believe that the consulting firm that they [Oncor] used, 1898 [and Co.] grounded this plan in metrics and in data. I think that is an important lesson to heed or to follow when we are giving out this much money carte blanche." ("Open Meeting at 9:30 AM November 14th," 00:57:05-00:57:34)[3] These public comments show that the 1898 & Co. modeling approach and model (the same one utilized in this proceeding) have provided confidence to the Texas Public Utility Commission to approve over $4 billion of electric distribution investment in hardening, pole inspections, distribution automation, telecommunication enhancements, technology implementation, and physical / cyber security investment.

Q23. Can you describe the Integrated Resilience, Reliability, & Risk Investment Model?

A23. The Integrated Resilience, Reliability, & Risk Investment Model employs a data-driven decision-making methodology using robust and sophisticated algorithms to calculate the resiliency, reliability, and risk benefits for each potential investment activity that makes up each of the nine DTE Electric distribution programs discussed above. It uses a suite of modules to assess the expected costs and benefits of specific investments activities. The model first includes foundational data, including DTE Electric's distribution asset register and equipment characteristics, which are used to determine the unique vulnerabilities of DTE Electric's system. Core to the model is the linkage between the infrastructure and the specific customers it serves. Specifically, the model builds the direct linkage between each asset on the DTE Electric system and the number and types of customers that would be

[2]Open Meeting at 09:30 AM. (2024). Public Utility Commission of Texas. Retrieved April 14, 2025, from https://www.adminmonitor.com/tx/puct/open_meeting/202410242/.

[3]Open Meeting at 09:30 AM. (2024). Public Utility Commission of Texas. Retrieved April 14, 2025, from https://www.adminmonitor.com/tx/puct/open_meeting/20241114/.

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impacted if the asset were to fail. This information feeds the rest of the model. An illustration of the Integrated Resilience, Reliability, & Risk Investment Model is attached as Exhibit A-28 Schedule R2.

Q24. How is the Integrated Resilience, Reliability, & Risk Investment Model structured?

A24. The Integrated Resilience, Reliability, and Risk Investment Model is structured as a comprehensive, multi-component analytical framework that integrates foundational data, advanced analytics modules, and plan development capabilities to evaluate the benefits and costs of DTE Electric's investment programs.

The model first incorporates foundational data, including DTE Electric's asset register, equipment characteristics, system topology, and customer information. These data are used to determine the unique vulnerabilities of DTE Electric's system. Core to the model is the direct linkage between infrastructure and the customers it serves. Specifically, the model establishes a relationship between each asset on the system and the number and types of customers that would be impacted if that asset were to fail. This asset-to-customer linkage forms the basis for quantifying customer impacts and feeds the subsequent analytical components of the model.

The model includes three primary analytics models: the Equipment Failure Mitigation Model, the Outage Mitigation Model, and, as enhanced for the 2026 analysis, a Resilience Event Simulation Model. The Equipment Failure Mitigation Model evaluates the probability and consequence of asset failures under normal operating conditions, while the Outage Mitigation Model utilizes historical outage data to estimate the reliability improvements associated with investments such as distribution automation. The Resilience

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Event Simulation Model represents a key enhancement in the 2026 analysis and is used to simulate the impacts of major weather events based on historical NOAA data and DTE Electric outage records. This model employs stochastic methods, including Monte Carlo simulation, to evaluate a wide range of potential storm scenarios and their associated customer impacts. Each of these analytics models estimates avoided costs and avoided customer outages, capturing the resilience, reliability, and risk benefits of different investment types.

In the 2026 analysis, this model also reflects the interaction between programs by evaluating investments in a structured order to avoid double counting of benefits.

Q25. What type of technology platform is the model built upon?

A25. As noted above, the model employs sophisticated and complex calculations by managing and integrating large datasets. As such, it is not a Microsoft Excel based model. The Resilience, Reliability, and Risk Investment Model resides within a suite of technology applications including an Extract Transform and Load (ETL) tool, SQL database, and, where applicable, Python scripts that are all managed through a tool called KNIME. This type of technology platform, as opposed to Microsoft Excel, is not only appropriate but expected. Firstly, the grid is a complex system, so to perform the type of detailed customer-centric benefit cost analysis to evaluate the grid investments requires a tool that can more accurately model this complex system. Secondly, the modeling includes cleansing, organizing, and merging large datasets into an integrated data model and performing robust and sophisticated calculations on that data model to calculate each potential project's benefit cost ratio. These large datasets include hundreds of thousands of records, and in some cases well over a million records which exceeds the limit of Microsoft Excel. A

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robust technology tool is needed to perform the type of data extraction, transformation, integration and sophisticated customer-centric benefit cost analytics to perform an asset, investment activity (grouping assets together), and circuit level evaluation. This type of modeling tool and platform is both appropriate and expected.

To run the models, 1898 & Co. uses virtual machines that are anywhere from 16GB to 128GB in size to operate the KNIME software which manages and executes the models. KNIME utilizes a node-based user interface with low-code logic for model development. This allows 1898 & Co. to utilize talent resources across a wide range of disciplines that don't require formal coding competencies to develop the models but are needed for understanding the asset, data, and business domain experience. This allows nominal users to navigate the models and understand the logic being included in the model. However, training is still needed to understand KNIME, typical utility data sets, and how they link, data integration logic, and other modeling logic. 1898 & Co. trains users on software and modeling, typically taking months to be fully trained. This training is needed more to understand utility data systems and what they represent, however some of it includes how to navigate and operate KNIME. Along with KNIME, other technology used for the models includes an ETL tool, SQL databases, and python scripts. Licensing and computing infrastructure are required to operate these models.

Q26. What is the Resilience, Reliability, and Risk BCR?

A26. The Resilience, Reliability, & Risk BCR, as used in this analysis, is a single value that represents complex modeling of resiliency and reliability failure modes, infrastructure vulnerability, infrastructure rebuild costs, and other financial factors to provide a robust and reliable measure to evaluate individual investments from a quantified customer benefit

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perspective. This singular value, the Resilience, Reliability & Risk BCR, for each DTE Electric distribution circuit, substation, and program level constitutes a sophisticated multi-factored analysis. This approach makes the BCR value a robust and reliable measure to help understand the justification for DTE Electric distribution investment activities.

Q27. Are there other benefit streams for these DTE Electric distribution investments that are not included in the quantified benefit cost analysis performed by 1898 & Co.?

A27. Yes. While the Resilience, Reliability, and Risk BCR incorporates a wide range of quantified benefit streams, it does not capture all potential benefits associated with DTE Electric's distribution and subtransmission investments. The BCR is designed to incorporate the majority of objective, quantifiable factors within the benefits assessment, including avoided customer outage impacts and avoided restoration costs. However, there are additional benefit streams that are difficult to quantify and therefore are not explicitly included in the modeled results.

Key qualitative benefit streams include improvements in public and worker safety, particularly through the reduction of equipment failures and hazardous conditions such as downed energized conductors. Investments also provide meaningful improvements in areas of lower system performance, including reductions in Customers Experiencing Multiple Interruptions ("CEMI"), as well as enhanced service reliability in disadvantaged or historically lower-performing areas. In addition, the 2026 analysis highlights broader customer and community impacts, including reduced customer disruption and anxiety associated with outages, and improved economic stability through more reliable electric service that supports business operations and community development. To account for qualitative benefits that are not directly quantified in a BCR, 1898 & Co. uses a BCR $\geq$ 0.9

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threshold for justification of investment. The Resilience, Reliability, & Risk BCR is an important tool for justifying investments. However, other, less-quantifiable, factors must also be considered. Integrating quantitative and qualitative assessments provides a more powerful decision-making tool for utility investments.

Further qualitative benefits include improved operations through long-term system hardening, asset standardization, and improved maintainability, which support more effective lifecycle asset management. Additionally, certain investments such as telecommunications infrastructure, subtransmission rebuilds, and voltage conversions enhance the grid's ability to support future electrification, distributed energy resources, and evolving customer demands. The analysis also recognizes increasing cyber-security and regulatory compliance considerations, including the potential need to address emerging standards and risks.

Q28. Can you provide additional details on the foundational data 1898 & Co. utilized in the Integrated Resilience, Reliability, & Risk Investment Model?

A28. The Integrated Resilience, Reliability, & Risk Investment model primarily relied on operational data from DTE Electric's Outage Management System ("OMS"), customer data (*e.g.*, customer type and location) from DTE Electric's Customer Information System ("CIS"), system data from DTE Electric's Geographic Information System ("GIS"), pole and pole top inspection data from historical inspections, and asset information from DTE Electric's asset register. NOAA data was used to identify historical weather events and link them to outages in the DTE OMS. This linkage was created to evaluate the impact of different weather events on the DTE Electric system. Various other data sources were also used to identify accessibility from public roadways and vegetation density.

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1 **Q29. How was the historical NOAA weather data used in the Integrated Resilience & Risk**
2 **Investment Model?**
3 A29. 1898 & Co. used the historical NOAA weather data for all counties within DTE Elecric's
4 service area to create a Major Event Database showing the type, frequency, and intensity
5 of resiliency events in those counties from January 1, 1998, through September 30, 2025.
6 1898 & Co. used this data to characterize the major resiliency events impacting DTE
7 Electric's service area and to develop the event-frequency assumptions used in the
8 resiliency modeling.
9
10 **Q30. How did 1898 & Co. use the data from NOAA and DTE Electric's OMS, CIS, and**
11 **GIS systems?**
12 A30. 1898 & Co. integrated data from the NOAA event database and DTE Electric's OMS,
13 customer information, and GIS systems to evaluate the impact of various weather events
14 on DTE Electric's infrastructure and customers.
15
16 First, 1898 & Co. used GIS and asset data to identify the assets on DTE Electric's system
17 and how those assets are electrically connected. Using that connectivity, 1898 & Co. linked
18 assets to the nearest upstream protective device (e.g., a fuse, recloser, or breaker) and
19 organized the system into protection zones. This protection-zone structure established the
20 relationship between infrastructure and the customers served by that infrastructure and
21 provided the foundation for evaluating potential weather event impacts and investment
22 activities.
23
24 Second, 1898 & Co. used NOAA weather-event data together with the Company's OMS
25 outage records to identify the types of major weather events affecting DTE Electric's

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service territory, how often those events occur, where they occur, and the customer outage impacts associated with those events. 1898 & Co. correlated the NOAA event data with DTE Electric's outage records using timestamps from both datasets and also supplemented the NOAA data by identifying additional weather events from OMS outage records coded as Weather or Lightning. This information was used to develop the Major Events Database, including event type, frequency, percentage of the system impacted, event duration, and restoration cost characteristics.

Third, 1898 & Co. used GIS, OMS, and related asset information to evaluate system vulnerability, including factors such as asset age, vegetation density, and accessibility, and to understand how those vulnerability characteristics relate to outage performance during weather events.

Finally, 1898 & Co. linked customer information data to GIS and OMS to identify the number and type of customers associated with each protection zone, circuit, and substation. That customer information was then combined with outage duration data to estimate Customer Minutes Interrupted and monetize outage impacts using the ICE 2.0 Calculator.

Q31. How did 1898 & Co. model benefits in the Resilience Event Simulation Model?

A31. The Resilience Event Simulation model includes three modules: (1) Major Event Database, (2) System Vulnerability & Event Impact Module, and (3) Resilience Benefit Module.

The Major Events Database uses historical NOAA weather-event data together with the Company's outage records to establish the universe of major weather events that can affect DTE Electric's service territory. This database includes information such as weather event

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type, event frequency by county section, the percentage of the system impacted, event duration, and associated restoration costs.

The System Vulnerability & Event Impact Module first estimates the vulnerability of each overhead asset and protection zone. The estimated vulnerability is based on the asset type, age, expected life, vegetation density, and accessibility. Vulnerability is established at both the asset and protection zone levels. Based on the system's vulnerability, the model simulates each event from the Major Event Database and its impact on the system to estimate the restoration costs and customer outages for each event. The module simulates the probability of protection zone failure based on the vulnerability of the assets in each zone and the event's strength. After identifying the number of probability-weighted protection zones to experience an outage, the module builds a restoration profile to restore each protection zone, which allows it to estimate the outage duration at the protection-zone level. The module also probabilistically estimates the number of asset failures within each protection zone and the restoration costs based on the number and type of failed assets and the expected restoration costs. This evaluation is performed for both a Status Quo and an Investment scenario. The results of this module are the expected benefits of investments, i.e., the differences between the Status Quo and Investment costs, for each combination of protection zone and event type.

To estimate the lifecycle benefits produced by a resilience investment in a protection zone, the Resilience Benefit Module applies the investment’s event-specific restoration and CMI benefits to a Monte-Carlo-simulation-generated collection of 50-year weather-event futures. The module incorporates escalation and discount rates to determine the present value of the lifecycle resilience and risk benefits expected for each protection zone.

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Applying the expected investment level for each protection zone, the module then calculates the BCR for each protection zone.

Q32. How did 1898 & Co. model resilience, reliability, and risk benefits in the Equipment Failure Mitigation model?

A32. The Equipment Failure Mitigation modeling approach calculates the benefits of replacing existing infrastructure. It forecasts the probability-weighted consequence of failure for a range of failure types. The failure types are based on how assets fail over their lifecycle, including inspection-based failures. Consequences are estimated for a range of factors but fall into two main categories. The first category is reactive or restoration costs. The second category is customer-based outages. This category is the monetization of customer outages in the event of an asset failure.

The approach calculates each asset's lifecycle reactive costs and customer outage costs for two scenarios. The first is a Status Quo scenario where the asset is not proactively replaced; the second scenario is the Investment scenario in which the asset is upgraded proactively to the new equipment standard. The benefit of replacing infrastructure is the difference between the two scenarios, the avoided resilience, reliability, and risk lifecycle costs. This analysis provides a clear calculation of expected benefits from implementation of specific investments on the DTE Electric system.

Q33. How did 1898 & Co. model benefits in the Outage Mitigation Model?

A33. The Outage Mitigation Modeling Approach utilizes the historical DTE Electric OMS data and recalculates each outage assuming the investments were originally in place. The approach fundamentally assumes future outages will be like historical outages. On average,

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this assumption is appropriate for performing the benefits assessment for investments. Using each outage's recalculated Customers Interrupted (CI) and CMI, the DOE ICE Calculator monetizes the mitigated outages by considering the types of customers impacted, count of customers impacted, and outage duration. The lifecycle present value of avoided customer outages is calculated by adjusting for inflation and discount rate over the lifecycle of the investment. This produces a lifecycle present value of benefits that can be directly compared to the cost of the investment through the BCR.

Q34. What are the benefits of 1898 & Co.'s approach to evaluating investments using the Integrated Resilience, Reliability, and Risk Investment Model?

A34. This approach has several benefits:

1. **It is comprehensive.** 1898 & Co. evaluated nearly all the assets on DTE Electric's overhead distribution system to identify opportunities for investments. By considering and evaluating the entire distribution system on a consistent basis, the results of the Integrated Resilience, Reliability, and Risk Investment Model provide confidence that portions of DTE Electric's' distribution assets are not overlooked for potential customer benefit.
2. **It is customer focused**. 1898 & Co.'s approach involved breaking DTE Electric's system into protection zones with a known number and type of customers. Protection zones are established based on the nearest upstream protective device. The failure of a single asset downstream of a protective device can cause a customer outage in that protection zone. Thus, aggregating assets into protection zones and evaluating investment activities at that level enabled the evaluation to provide a direct link between investments in vulnerable infrastructure and the benefits to customers.

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3. **It is asset centric.** The granularity of modeling at the asset level and identifying for replacement of vulnerable equipment allows DTE Electric to invest in portions of the system that provide the most value to customers, as measured by the monetization of the reduction in the frequency and duration of customer outages and avoided system restoration costs. With the number of assets in the DTE Electric system and the numerous types of failure events that impact the service area, careful choices must be made to prioritize investments.

4. **It drives consistency**. The modeling calculates benefits consistently for all investment activities, estimating both the monetized avoided customer outages and avoided reactive costs. The model carefully normalizes for a more accurate comparison of potential benefits between investment types. This provides additional confidence in the BCA across the DTE Electric distribution programs.

5. **It is rooted in the causes of equipment failures**. The model incorporates how assets fail and their different drivers as well as consequences. The detailed data streams and algorithms within the model are aligned with how assets fail – mainly vegetation density and asset age. Additionally, it incorporates additional drivers of asset consequence for rear-lot infrastructure and makes allowances for geography. This aligns the modeling to engineering based principles of infrastructure failure.

6. **It is practical.** This approach balances robust historical data with DTE Electric's operational expertise to estimate benefits for investments that will have a practical impact. Data-only approaches may identify solutions that work in theory but not in practice. This approach balances the two approaches to identify investments that will have a practical impact.

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Q35. You have noted that the 1898 & Co. model employs robust and sophisticated algorithms to calculate the benefits for each of the potential investments. What approaches have you used to explain how the model works?

A35. As noted above, the model is not a Microsoft Excel tool, rather it utilizes a tool called KNIME. 1898 & Co. strives to enable understanding and to provide transparency on how the Integrated Resilience, Reliability, & Risk Investment Model is structured, organized, operated, and utilized. To meet this objective, we have employed several approaches. First, we have provided several exhibits associated with my testimony. Exhibit A-28 Schedule R1 includes links to all the previous cases that the modeling approach has been leveraged. Exhibit A-28 Schedule R2 includes an illustration of the model structure. Schedule A-28 Schedule R3 Revised, the Program Benefit Cost Analysis Report includes a more detailed review of the model and modeling approach. The report includes a more detailed review of the various data streams that feed the model and how they are related. Further it includes example calculations of foundational analytics including graphical representation of the approach around these analytics engines. Second, we regularly host technical conferences with intervening parties showing them the model, providing a demonstration of calculations, and answering additional questions beyond those provided in discovery. 1898 & Co. provided two such technical conferences on the BCA for interested parties in DTE Electric's prior electric rate case proceeding in Case No. U-21860. In addition, 1898 & Co. has hosted these technical conferences for the following cases, links provided in Exhibit A-28 Schedule R1: AEP Ohio for their gridSMART Phase 3 DACR (Distribution Automation Circuit Reconfiguration) plan in 2024, Baltimore Gas & Electric (BGE) for their Multi-Year Plan in 2023, Entergy Louisiana for their 10 year Resiliency Plan in 2022, Oklahoma Gas & Electric (OG&E) for their Grid Enhancement Business Case in 2022, and Tampa Electric in their Storm Protection Plan filing in 2020. The intervenors in these

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technical conferences often include the state's designated public intervenor and their technical consultants. The Wired Group, one of the supporting technical consultants to the designated public intervenors, has been a part of technical conferences hosted by 1898 & Co. in the AEP Ohio, BGE, and OG&E cases outlined above.

Q36. How does the BCA approach employed by 1898 & Co. balance the use of robust and sophisticated analytics within the technology platform and transparency?

A36. The BCA approach balances transparency and sophistication by combining a detailed, data-driven modeling framework with a structure that can be clearly explained and reviewed. On the one hand, the analysis is sophisticated because it integrates large asset, outage, customer, and weather-event datasets and applies multiple analytics models, including the Resilience Event Simulation Model, the Equipment Failure Mitigation Model, and the Outage Mitigation Model, to quantify avoided customer outage impacts and avoided restoration costs. That level of sophistication is necessary because DTE Electric's system is complex and the evaluation must account for factors such as asset condition, customer connectivity, weather-event exposure, outage duration, and restoration consequences in a consistent and customer-focused manner.

To help with model transparency 1898 & Co. organized the analysis into clearly defined data inputs, modeling steps, and benefit calculations. The 2026 BCA Report describes the foundational datasets, the assumptions used in the evaluation, the sequence of modeling operations, and the way benefits are calculated for each program. To provide greater transparency into the modeling approach and resulting outputs, 1898 & Co. is willing to offer model navigation sessions to provide guided walkthrough of the models used, including key inputs, assumptions, and processes applied to produce the BCA results.

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Additional details degrading these model navigation sessions are provided in Part IV by Company witness Kryscynski.

Q37. Can you provide an overview of the Custom BCA for the Communications Network Program?

A37. 1898 & Co. used a customized Benefit-Cost Analysis approach for the Communications Network Program because communications investments are fundamentally different from the other programs evaluated in the 2026 BCA. Unlike programs such as PTMM, DA, or other direct infrastructure replacement investments, the communications network is an enabling investment. The communication network provides the platform needed to support grid operations and future grid modernization, but it does not by itself produce the same type of direct customer outage benefits. For that reason, the analysis was structured as a least-cost, life-cycle evaluation rather than through the standard Integrated Resilience, Reliability, and Risk Investment Model used for direct-benefit programs. This customized approach was also intended to identify the preferred long-term system-wide or "North Star" communications strategy, recognizing that communications investments are especially sensitive to re-investment risk, long-term technology alignment, local optimization, and the treatment of sunk system-level costs.

Under that customized framework, 1898 & Co. performed a direct comparison between continued reliance on public cellular service and deployment of a private cellular solution supported by fiber backhaul. The analysis evaluated those alternatives over a long-term study horizon and under multiple device-growth scenarios to determine which alternative provides the lower life-cycle cost for DTE Electric and its customers. The analysis focused on the major cost drivers associated with each alternative, including device investments,

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end-of-life replacements, obsolescence-driven replacements, carrier service fees, network infrastructure build-out, and network operations and maintenance.

Further, the model allocates various costs to each substation and fiber route to perform the least cost benefit cost analysis for each proposed fiber route.

Q38. Please explain the approach used for the Subtransmission Redesign and Rebuilds and 4.8 kV and 8.3 kV Conversions?

A38. For both the Subtransmission Redesign and Rebuild Program and the 4.8 kV and 8.3 kV Conversion Programs, 1898 & Co. used a project-specific Benefit-Cost Analysis approach based on the Resilience Event Simulation Model and the Equipment Failure Mitigation Model. DTE Electric provided project-level scoping documentation describing the circuits and substations involved, the quantities of infrastructure to be replaced, retired, installed, or converted, and the estimated project costs. 1898 & Co. reviewed that scoping information and translated each project into asset-level investment activities that could be evaluated within the broader BCA framework.

In doing so, 1898 & Co. used DTE Electric's GIS and Maximo data to map the scoped work to the specific assets associated with each project so that the analysis would reflect the relationship between the infrastructure being replaced, the likelihood of equipment failure, and the customers affected by that infrastructure. Assets associated with these projects were also evaluated separately and were not included in the other program analyses.

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Using that approach, 1898 & Co. evaluated the reliability, resilience, and risk-reduction benefits associated with replacing, upgrading, or retiring aging infrastructure and modernizing legacy system configurations. The analysis estimated avoided customer outage impacts and avoided restoration costs by comparing the expected performance of the existing infrastructure with that of the proposed project scope. The expected cost of each project was based on project-level cost estimates provided by DTE Electric, and those costs were then compared with the quantified benefits generated by the modeling. In that respect, the approach for both programs was to evaluate each project on its specific scope and asset composition, while using a consistent resilience, reliability, and risk-based framework to measure customer and system benefits.

Q39. Is 1898 & Co. willing to host a technical conference for interested parties in this case?

A39. Yes, in the interest of transparency, 1898 & Co. will host a technical conference, similar to what was done for the previous rate filing, to walk through the Resilience, Reliability, and Risk Investment Model and each major component for interested parties, subject to appropriate protection under the protective order issued in this case. Attendees are requested to read and review the Program Benefit Cost Analysis Report, provided as Exhibit A-28, Schedule R3 Revised, and will be required to sign the instant case Non-Disclosure Agreement ahead of the meeting to ensure conference efficiency.

In an effort to provide an even greater degree of transparency 1898 & Co. will also host model navigation sessions, as requested, where interested parties are given complete access to any of the models to review inputs, calculations, and code. These sessions will allow interested parties to review models directly on 1898 & Co. computers and servers. Due to the size of the models and the computing resources required to host the models, it is not

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practical to provide the models as exhibits. These navigation sessions are intended for experts to review the model and ask technical model function questions. More detailed or specific questions will still need to be submitted through the audit and discovery process. Eight business days notification will be required to align and schedule the appropriate resources to guide the review for the specific model requested. Because 1898 & Co. models contain detailed electric system information, participants in navigation sessions will be subject to appropriate confidentiality protection under the protective order issued in this case.

Part III: Benefit Cost Analysis Results

Q40. Can you provide an overview of the BCA results for the seven programs analyzed completely in the Integrated Resilience, Reliability, and Risk Investment model?

A40. Yes. The Benefit-Cost Analysis shows that the evaluated programs include a portfolio of investments supported by quantified resilience, reliability, and risk-reduction benefits. A summary of the results of each of these programs is outlined in the table below[4].

Table 2 Summary of BCA Results

Program	Total Benefits	Total Investment	Total Benefits BCR ≥ 0.9	Total Investment BCR ≥ 0.9	% of Investment with BCR ≥ 0.9	Weighted BCR of Activities BCR ≥ 0.9
PTMM Groundline	$7.77B	$2.97B	$7.7B	$2.86B	96.3%	2.69
PTMM Pole Top	$3.96B	$853.3M	$3.94B	$827.48M	97%	4.76
Small Wire Replacement	$5.67B	$5.25B	$4.58B	$2.39B	45.5%	2.09

[4] The Company's projected and proposed investments for this instant case in each of these programs are identified in Exhibit A-12, Schedule B5.4 Revised, and Exhibit A-33, Schedule X1. PTMM Groundline and PTMM Pole Top investments are included within the overall Pole and Pole Top Maintenance and Modernization category.

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Program	Total Benefits	Total Investment	Total Benefits BCR ≥ 0.9	Total Investment BCR ≥ 0.9	% of Investment with BCR ≥ 0.9	Weighted BCR of Activities BCR ≥ 0.9
Breaker Replacement	$1.58B	$2.29B	$967.21M	$857.27M	37.4%	1.13
URD Replacement	$1.54B	$3.63B	$447.55M	$420.58M	11.6%	1.06
Cable Replacement	$4.93B	$8.06B	$1.33B	$1.22B	15.1%	1.09
Subtransmission SCADA	$1.28B	$161.87M	$1.27B	$93.61M	57.8%	13.52
Distribution Automation	$1.19B	$868.46M	$1.03B	$380.14M	43.8%	2.71

As the table shows, the PTMM program, similar to the 2025 BCA results, produced strong results and demonstrates that targeted inspection and replacement of poles and pole-top components provides meaningful customer value through reduced outage impacts and avoided restoration costs.

The Small Wire Replacement Program also identified a meaningful set of targeted investments that provide customer benefits, particularly where the underlying infrastructure presents elevated vulnerability.

The Breaker Replacement, URD Replacement, and Cable Replacement Programs identified portions of investment that produce quantified benefits, while also providing important operational, community and safety-related value that is not fully reflected in the quantitative results alone.

Line No.

The Subtransmission SCADA Program and the DA Program also showed meaningful quantified customer value. The analysis demonstrates that targeted automation and switching investments can reduce outage impacts and improve restoration performance for customers.

Q41. Can you provide an overview of the BCA results for Communication Network Program?

A41. The Communication Network Program is an enabling, system-wide investment evaluated using a least-cost framework rather than a traditional benefit attribution approach. Reported benefits represent avoided life-cycle costs relative to continued reliance on public cellular services, not direct reliability or operational benefits. Under the likely device growth scenario, the total investment is $6.9 billion with a BCR of 1.58. The results for High and Low device growth scenarios are presented in the Communication Network Section 5.8 of Exhibit A-28 Schedule R3 Revised. For individual substation and fiber routes, the BCA similarly shows the Private Cellular alternative is the preferred solution.

Q42. Can you provide an overview of the BCA results for the Subtransmission Redesign and Rebuild Projects?

A42. The Subtransmission Redesign and Rebuild projects evaluated by 1898 & Co. represent a total investment of approximately $405 million over the next five years. The results indicate that several projects provide strong quantified reliability and resilience benefits, while others address important capacity, operability, and safety needs that are not fully captured in the quantitative BCA.

Line No.

Q43. Can you provide an overview of the BCA results for the 4.8 kV and 8.3 kV Conversion projects?

A43. The 4.8 kV and 8.3 kV Conversion projects represent a total investment of approximately $2.9 billion over the next five years. For these programs, the analysis indicates that a majority of projects provide strong, quantified reliability and resilience benefits, with additional value from improvements in operations, safety, and load-serving capability.

Part IV: Summary and Conclusion

Q44. What conclusions can be drawn from the benefit cost analysis performed by 1898 & Co.?

A44. The following are the high-level conclusions of the benefit cost analyses for the DTE Electric distribution programs in this rate case evaluated by 1898 & Co. that are included in DTE Electric's rate case as evaluated within 1898 & Co.'s Integrated Resilience, Reliability, & Risk Investment Model:

- The Resilience, Reliability, and Risk Benefit-Cost Ratio ("BCR") is a robust and reliable measure to help evaluate the justification for investment activities. The 2026 BCA applies a consistent, data-driven framework to quantify avoided customer outage impacts and avoided restoration-related costs and, in doing so, provides a practical and customer-centric basis for investment prioritization.
- The 2026 BCA is enhanced through the incorporation of storm and resiliency modeling. Unlike the prior analysis, the 2026 BCA evaluates the impact of various weather events on DTE Electric's system by using historical NOAA weather data, DTE Electric outage records, and simulation of future weather-event outcomes. This addition allows the analysis to better capture the customer and system consequences of severe events, including long-duration outages and restoration

Line No.

1 challenges, and better quantifies the value of investments that reduce infrastructure
2 vulnerability, improve system performance during weather events, and strengthens
3 overall grid resilience.

4 • Compared to the prior analysis, the 2026 BCA reflects an expanded scope of
5 programs, updated asset and outage data, updated interruption-cost assumptions
6 through ICE 2.0, updated unit costs, and the addition of resilience-event simulation
7 to better capture the consequences of major weather events affecting DTE Electric's
8 system. This expanded resilience modeling improves the ability of the analysis to
9 reflect actual system risk and provides a stronger analytical basis for identifying
10 investments expected to provide meaningful customer value.

11 • The Pole and Pole Top Maintenance & Modernization program, similar to the
12 conclusions from the 2025 BCA, is beneficial for DTE Electric customers and
13 provides a significant opportunity to improve resiliency, reliability and manage
14 safety risks on the system. The modeling shows that over 96 percent of the potential
15 investment for the distribution system has a benefit cost ratio greater than 0.9.

16 • The Small Wire Replacement Program identified targeted circuits where benefits
17 can be gained by improving the resilience and reliability of DTE Electric's
18 overhead distribution system through targeted rebuilds of protection zones
19 containing qualifying small wire. The BCA shows that this program is beneficial
20 for DTE Electric customers with nearly $2.4 billion of investment with a BCR
21 greater than 0.9 and an average BCR of 2.09.

22 • The Breaker Replacement, URD Replacement, and Cable Replacement Programs
23 provide targeted opportunities to reduce outage impacts and reactive restoration
24 costs by proactively replacing aging and higher-risk infrastructure. These programs
25 also provide important qualitative benefits not fully captured in the quantified BCA,

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1 including improved operability, maintainability, fault-clearing performance, and
2 reduced safety exposure from reactive repair work.

3 • The Subtransmission SCADA Program demonstrated value at specific locations
4 where additional switching capability can improve the performance of DTE
5 Electric's subtransmission system. The subtransmission system serves as the
6 critical link between the transmission network and the distribution substations that
7 ultimately serve customers, and it is designed to provide redundancy through trunk
8 and tie line configurations. By adding SCADA-enabled Automatic Pole-Top
9 Switches, DTE Electric can better isolate faults, leverage existing system
10 redundancy, reduce outage duration, and lessen the customer impacts of high-
11 consequence subtransmission outages. In that respect, the program supports both
12 improved reliability and improved operational flexibility on a portion of the system
13 where outages can affect large numbers of downstream customers.

14 • The DA Program continues to provide meaningful customer value by reducing the
15 impact of outages through increased sectionalization and automated switching on
16 DTE Electric's distribution system. The 2026 BCA shows that the program remains
17 beneficial and can materially reduce customer outage impacts. Relative to the prior
18 analysis, however, the quantified Benefit-Cost results are lower primarily due to
19 two factors: the transition from the ICE 1.0 to ICE 2.0 calculator, which reduces
20 the monetized value of non-residential outages, and the integrated modeling
21 assumption that vegetation management and PTMM have occurred before DA
22 benefits are evaluated, which reduces the remaining incremental benefit available
23 to the DA program. However, when considering the level of investment into this
24 program, the conservative nature of the evaluation and the expected changes with
25 ICE 2.2, as the BCA report describes, utilizing ICE 2.2 could increase the benefits

Line No.

for this program by 25 to 40 percent for most circuits. As this program matures and the evaluation approach is enhanced to account for the conservative nature of the evaluation described above, 1898 & Co. expects the level of investment for this program to expand for the benefit of DTE Electric customers.

- The Subtransmission Redesign and Rebuild Program and the 4.8 kV and 8.3 kV Conversion Programs include critical projects that address aging infrastructure, improve switching and restoration capability, strengthen system operability, and support future load growth. Many of the projects have been proven to be cost effective by the monetized benefit cost ratios alone. Yet all the projects analyzed provide important tangible, qualitative benefits to DTE Electric customers.
    - For the Subtransmission Redesign and Rebuild Program specifically, those additional benefits include improved operational flexibility, greater ability to isolate faults and transfer load including N-1 contingency events, improved maintainability, reduced exposure to vegetation-related outages where facilities are relocated to more accessible corridors, enhanced crew safety, and reduced risk of catastrophic equipment failures on backbone facilities that can interrupt service to large portions of the system. In that respect, these projects should not be viewed solely through their quantified BCR results, because they also support DTE Electric's obligation to provide safe, reliable, operable, and resilient electric service.
    - For the 4.8 kV and 8.3 kV Conversion Programs, additional qualitative benefits include improved public and worker safety through the reduction of risks associated with aging legacy equipment and downed energized conductors, simplification and standardization of system operations and maintenance, improved voltage performance and capacity, and enhanced

Line No.

ability to accommodate future load growth, electrification, and distributed energy resources. In that respect, these projects should not be viewed solely through their quantified BCR results, because they also support DTE Electric's obligation to provide safe, reliable, operable, and resilient electric service.

- The Communication Network analysis supports a clear long-term strategic direction. The analysis indicates that a Private Cellular solution supported by fiber backhaul represents the lowest life-cycle cost communications strategy relative to continued reliance on public cellular service. In addition to the quantified cost advantage, this approach supports future grid modernization through a more scalable, secure, and operationally aligned communications platform.
- Many of the programs will benefit all DTE Electric customers. The nature of many of the programs is widespread across the entire DTE Electric system. The avoided reactive and investments costs are shared by all distribution customers. Additionally, distribution customers will experience fewer storm outages from both direct and indirect factors. Direct benefits are realized by those customers whose infrastructure is located directly downstream of the resiliency investment. Indirect benefits are realized by all distribution customers since storm restoration crews will be able to rebuild the system quicker because less infrastructure will fail.
- The investment benefits are conservative. First, the use of the ICE Calculator is conservative as the BCA utilizes the ICE 2.0 calculator. A recent update to the calculator, ICE 2.2, shows the cost of interruptions for DTE Electric's C&I customers is approximately 50 percent higher for most outage durations. Second, the quantified evaluation only considers direct benefits to events and does not factor in the indirect benefits from lower overall storm restoration durations. Third, the

Line No.

quantified benefit cost assessment has carefully included the full cost of implementing investments; however, the full level of benefits has not been captured. Specifically, the evaluation has not incorporated qualitative benefits associated with safety, mitigation cyber risk, or service improvement in areas of lower performance where quantified benefits are not in excess of cost.

Overall, the 2026 BCA supports the conclusion that DTE Electric's proposed investment portfolio is both economically justified and strategically aligned with long-term system needs. While not every individual project produces benefits in excess of cost, the combined portfolio, supported by both quantitative results and qualitative considerations, provides value to customers through improved reliability, reduced outage impacts, enhanced safety, increased resilience, and improved system capacity and operability to meet future load growth and distributed energy resource integration.

Q45. Does this conclude your direct testimony?

A45. Yes, it does.

PROGRAM BENEFIT-COST ANALYSIS REPORT 2026

DTE ENERGY

PROJECT NO. 189594

April 15, 2026

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TABLE OF ACRONYMS

Acronym	Term/Phrase/Name
ADMS	Advanced Distribution Management System
AMI	Advanced Metering Infrastructure
APTS	Automatic Pole Top Switch
ATO	Automatic Throwover
BCA	Benefit-Cost Analysis
BCR	Benefit-Cost Ratio
CDF	Customer Damage Functions
CEMI	Customers Experiencing Multiple Interruptions
C&I	Commercial & Industrial
CI	Customers Interrupted
CIS	Customer Information System
CMI	Customer Minutes Interrupted
$CMI	Monetized Customer Minutes Interrupted
CODI	City of Detroit Infrastructure
DA	Distribution Automation
DOE	Department of Energy
ELC	Emergency Load Control
ESOC	Electric System Operations Center
GIS	Geographic Information System
ICE	Interruption Cost Estimator
ISO	Isolation
MED	Major Event Day
OMS	Outage Management System
PTMM	Pole and Pole Top Maintenance & Modernization
ROW	Right-of-Way

Acronym	Term/Phrase/Name
SCADA	Supervisory Control and Data Acquisition
URD	Underground Residential Distribution

1.0 Executive Summary

DTE Electric (DTE) engaged 1898 & Co., the advisory and technology consulting arm of Burns & McDonnell, to perform a Benefit-Cost Analysis (BCA) for multiple investment programs included within DTE's rate case filing. The programs include:

1. Pole and Pole Top Maintenance & Modernization (PTMM)
2. Small Wire Replacement Program
3. URD Replacement Program
4. Cable Replacement Program
5. Breaker Replacement Program
6. Subtransmission SCADA
7. Distribution Automation (DA)
8. Communication Network
9. Subtransmission Redesign and Rebuild
10. 4.8 kV & 8.3 kV Conversion Programs

The evaluation also supported the selection of investment activities by using Benefit-Cost Ratios (BCRs) for investment activities across the programs. 1898 & Co. used a resilience, reliability, and risk-based planning approach to perform the Benefit-Cost Analysis of investment activities by using the Integrated Resilience, Reliability, and Risk Investment Model developed by 1898 & Co. The key objectives for the Integrated Resilience, Reliability, and Risk Investment Model are to:

- Quantify the improvement expected for individual investment activities and programs, specifically estimating benefits from a customer-centric perspective, avoided future costs to repair or replace assets and value of reduction in customer outages,
- Demonstrate the expected improvement in the number and duration of customer outages for programs, and
- Identify and prioritize investments with the highest quantified benefit per dollar invested into the system.

1898 & Co.'s Integrated Resilience, Reliability, and Risk Investment Model uses a data-driven, decision-making methodology utilizing sophisticated algorithms to calculate the resilience, reliability, and risk mitigation benefit of investments by identifying the expected range of reduced duration and frequency of customer outages, measured as Customer Minutes Interrupted (CMI), and reduced outage restoration costs. The Benefit-Cost approach and model utilized by 1898 & Co. support the identification of investments that provide the most benefit to DTE's customers. Utilizing the Benefit-Cost Analysis as a decision-making tool for investments in the electric delivery system helps provide confidence that investments are justified from a customer-centric perspective and the overall level of investment for each program is appropriate.

This report outlines the data (Sections 2.0 and 3.0) and methodology (Section 4.0) 1898 & Co. used to perform the Benefit-Cost Analysis for the programs outlined above. The report also includes results (Section 5.0) from the Benefit-Cost Analysis at both program and investment-activity levels. Throughout this report, investment activity refers to a specific scope of work designed to produce resilience, reliability, and/or risk-mitigation benefits for some collection of assets on the electric delivery system. Depending upon the program and type of investment, an investment activity can be at the individual-asset, protection-zone, subtransmission-line, circuit, or substation level. Finally, the report includes 1898 & Co.'s conclusions for these programs based on the Benefit-Cost Analysis (Section 1.4). The following sub-sections provide a summary of the key sections of this report.

1.1 Key Updates from the 2025 to 2026 Benefit-Cost Analysis

Multiple changes have been made for the 2026 analysis. Key changes include both the expansion of programs analyzed and the approach to quantifying benefits and impacts for replacing infrastructure. In the 2025 Benefit-Cost Analysis (BCA), three programs and two pilot projects were analyzed as listed below:

- PTMM
- Distribution Automation
- Grid Automation Telecommunications
- Spruce strategic undergrounding pilot project

- Attica strategic undergrounding pilot project

For the 2026 Benefit-Cost Analysis, the analysis was expanded to the 10 programs listed above. In addition to the increase in the number of programs analyzed the following changes for benefits modeling and key inputs were also incorporated:

1) Resiliency modeling for the impact of storms on DTE assets (Section 3.0 and Section 4.3),
2) Updated analysis on the PTMM pole inspection reject rates (Section 2.6),
3) Quantification of benefits from customer outages by moving from the ICE 1.0 to ICE 2.0 calculator (Section 4.2),
4) Integrated sequence of programs that model benefits by starting with Vegetation Management, then PTMM, and accounting for DA last (Section 4.7), and
5) Adjusted approach to the Grid Automation Telecommunication to a least-cost comparison between two potential long-term future states, public cellular compared to private cellular supported by fiber backhaul (Section 5.8).

As a minor update, unit costs for PTMM and Distribution Automation were also provided by DTE. The 2026 Benefit-Cost Analysis (BCA) represents a substantial evolution from the 2025 analysis, in scope, inputs, and modeling methods. The 2025 analysis focused on three programs and two underground pilot projects and primarily evaluated reliability and risk reduction using a deterministic, circuit-level framework. In contrast, the 2026 Benefit-Cost Analysis expands the analysis to a comprehensive portfolio of distribution and subtransmission programs and adopts a fully integrated, system-level modeling approach. This expanded scope results in a significantly larger asset base being evaluated and introduces a broader range of investment categories, including additional replacement and modernization programs that were not considered in the prior analysis.

1.1.1 Resilience Modeling Updates

A key distinction between the 2025 and 2026 BCA is the treatment of resilience events. While the 2025 analysis incorporated the general risk of weather events, it did

not explicitly model the impact of the specific major weather events that impact DTE's territory. The 2026 evaluation introduces a formal resilience modeling framework that leverages historical NOAA data, outage records, and Monte Carlo simulation techniques to quantify the effects of high-impact, low-probability storm events. This addition materially changes the benefit estimation through a more granular analysis on the likelihood and consequence of varying storm types.

1.1.2 PTMM Updates

From the 2025 analysis, system-wide, PTMM groundline inspection program spending of approximately $1.66 billion yielded a Benefit-Cost Ratio (BCR) of 1.69. Meanwhile, the pole-top program spending of approximately $709 million yielded a BCR of 2.76. Taken together, the two programs totaled nearly $2.4 billion in investment. A key observation from the 2025 analysis was that $2.3 billion or 97% of PTMM investment, over both programs, produced positive benefits. These economic benefits were primarily from avoided outage costs and reduced restoration expenses, little of which were attributed to extreme weather events due to the modeling approach of the 2025 analysis. So, the 2025 analysis demonstrated clear net benefits for the PTMM programs while, at the same time, likely underestimating the overall magnitude of the Resilience, Reliability, & Risk Benefits available in the presence of extreme weather events.

In contrast, the 2026 analysis reflects an increase in both capital investment and monetized benefits, fundamentally improving the BCR of the PTMM programs. Total investment requirements increase, with the groundline program increasing to approximately $2.97 billion and the pole-top program increasing to approximately $853.3 million. In the 2026 analysis, $2.86 billion or 96.3% of the groundline investment had a BCR ≥ 0.9. For the pole-top program, $827.5 million or 97% of the investment had a BCR ≥ 0.9. The investment increases result, primarily, from a combination of higher inspection defect rates and higher unit costs. The unit costs for the 2026 analysis are higher due to inflation, and the consideration of more available granular unit cost data based on actual program construction such as cable poles, poles with line transformers and poles without street access.

The groundline program's BCR increases to a system-wide weighted value of 2.62, while the pole-top BCR increases to a system-wide weighted value of 4.64. That is, the 2026 PTMM-program analysis identified substantially more economic benefit than was apparent from the 2025 analysis. Key to the increase in economic benefit was the inclusion of resilience-based benefits associated with mitigating the effects of major weather events. By considering these weather events (outlined in Section 4.3), this 2026 analysis captured the benefits of avoiding long-duration outages, which have very high customer consequences. Consideration of these consequences, expressed as the monetized cost of customer minutes interrupted (CMI), increased the calculated costs of outages, and the benefits of avoiding them.

1.1.3 ICE Calculator Updates

Lawrence Berkeley National Laboratory and Resource Innovations, Inc. started the "ICE 2.0 Initiative" in 2021 with the goal of updating the interruption cost calculator (ICE) to reflect advancements in the societal use of electronic devices, in-home life-saving medical devices, and other technologies, including a higher number of people working from home. The ICE initiative is being released in various phases and for each phase of the "ICE 2.0 Initiative" more surveys of customers will be used to update the cost of interruption. The ICE calculator is being released in phases based on different surveys collected from utilities across different regions of the United States and is aggregated based on all regions collected. Phase 1 was released in May 2025, and phase 2 was released in late February 2026. Additional updates are also expected over the coming years, which could include more regionally focused results as opposed to averages of the respondents regardless of location. While phase 2 was released before the filing of this application, the release timing of late February 2026 was too late to incorporate into the Benefit-Cost Analysis. As such, this analysis is based on the phase 1 release, ICE 2.0. The phase 2 release is classified as ICE 2.2. The following includes a summary of the differences between ICE 1.0, 2.0 and 2.2. More detailed comparisons are provided in Section 4.2.

The valuation of customer outage impacts differs between the 2025 and 2026 BCA due to the transition from the ICE 1.0 to ICE 2.0 calculator (phase 1). The updated ICE 2.0 calculator incorporates more recent and consistent survey data than ICE 1.0, as well as more detailed data regarding commercial and industrial customers. This change has altered the monetization of outage durations and customer classes. In comparing the impact of the ICE 1.0 calculator utilized in the 2025 analysis to the ICE 2.0 (phase 1) calculator for the 2026 analysis, 1898 & Co. utilized information from the developers of the ICE tool as well as cost of interruption analysis for DTE's customers. The following provides a high level overview of the impacts of moving from ICE 1.0 to 2.0:

- **Residential Customers**: the cost of interruption values across a range of outage durations are very similar. For outages less than 1 hr, ICE 2.0 is less than ICE 1.0, however, for outages longer than 1 hour, ICE 2.0 is slightly higher than ICE 1.0 with the values being nearly the same at 12 hours and greater.
- **Non-Residential Customers:** the cost of interruption values for DTE's system is lower for ICE 2.0 compared to ICE 1.0 for all outage durations. The difference is not constant across outage durations. For outage durations of 120 minutes or less, ICE 2.0 is approximately 20 percent lower than ICE 1.0 for DTE's system. For outages greater than 480 minutes, ICE 2.0 is approximately 60 percent lower than ICE 1.0.

With the recent release of phase 2 of the ICE calculator, known as ICE 2.2, the value of the loss of service for residential and non-residential (C&I) customers have been updated based on expanded survey data. The impact of the change from ICE 2.0 to ICE 2.2 for residential customers shows a minor decrease (ICE 2.2 is approximately 2 percent lower than ICE 2.0) while the C&I customers change is notable. For DTE's system, ICE 2.2 is approximately 50 percent higher than ICE 2.0 for outage durations less than 480 minutes. For longer duration outages, over 24 hours, ICE 2.2 is approximately 25 percent higher than ICE 2.0. This demonstrates that the phase 2 release (ICE 2.2) would have a significant impact on the value of outages in the analysis. For many programs the key benefit stream is avoided customer outages.

Based on this information, 1898 & Co. considers the BCA results to be conservative, especially for programs where the benefits are mainly avoided customer outages and focused on circuit backbones where these C&I customers typically are served from.

It is also useful to understand the comparison of ICE 2.2 and ICE 1.0 for the C&I customers on DTE's system. 1898 & Co. observed the following when comparing the outage cost results between the two calculators:

- ICE 2.2 is approximately 25 percent higher than ICE 1.0 for outage durations less than 120 minutes
- ICE 2.2 and ICE 1.0 are approximately equal in customer impacts for 240 minute outage duration
- ICE 2.2 is significantly lower than ICE 1.0 for outage durations of 480 minutes or more ranging from approximately 40 percent to 55 percent lower than ICE 1.0.

Even as the ICE Calculator evolves through successive phases, it remains a valid and credible tool for estimating the economic cost of power interruptions because its updates reflect improvements in data quality, sample size, and model specification, not a change in the fundamental methodology. The transition to ICE 2.2 incorporates a larger and geographically diverse set of customer surveys, as well as additional explanatory variables that capture how different customer characteristics influence outage costs.

Importantly, these updates were necessary because ICE 1.0 was based on survey data collected between 1989 and 2012, using independently designed studies with inconsistent methodologies and limited geographic representation. Over time, changes in electricity use, such as increased digital dependence, automation, and work-from-home trends, have altered how customers experience and value reliability.

The enhancements in ICE 2.0 and 2.2 are therefore expected to shift estimated outage values, such as increases in certain non-residential interruption costs, not because the tool is less reliable, but because it is reflecting current customer behavior and economic conditions. The core framework of the ICE Calculator which uses statistically derived Customer Damage Functions (CDFs) that are based on

empirical survey data, remains consistent across versions, which helps provide continuity and comparability.

Overall, the ICE Calculator should be viewed as a living, data-driven model. Its periodic updates strengthen its validity by keeping outage cost estimates current, representative, and analytically robust, which is essential for utility planning, reliability investment decisions, and regulatory analysis.

1.1.4 Integrated Sequence of Programs Modeling Approach

The Integrated Sequence of Programs Modeling Approach applies a defined sequencing of programs to reflect how multiple investments interact on the same portions of the electric system and to avoid double-counting benefits. Because several programs can affect the same outage mechanisms, 1898 & Co. did not evaluate each program in isolation and fully independent. Instead, the modeling framework evaluates programs in a logical sequence such that the benefits attributed to each program reflect only the incremental improvement associated with that investment after preceding programs are considered.

Under that sequencing, the modeling first reflects the effect of vegetation management, then evaluates PTMM, and then evaluates Distribution Automation. This order is important because vegetation management, PTMM, and DA can each affect outage frequency and outage impact on the same circuits. For example, vegetation management may reduce the likelihood of tree-related outages, PTMM may reduce failures associated with aging pole infrastructure, and DA may reduce the number of customers interrupted when an outage occurs. By sequencing the analysis in that manner, the PTMM BCA is evaluated on a system that already reflects the impact of vegetation management, and the DA BCA is evaluated on a system that already reflects both vegetation management and PTMM. As a result, the benefits shown for DA represent the remaining incremental benefits after those preceding investments are taken into account.

This sequencing makes the Integrated BCA more conservative and more representative of how the programs work together in practice. It allows 1898 & Co. to evaluate

multiple programs within a single integrated framework while providing greater confidence that the quantified benefits are not overstated. In that respect, the sequencing is a key part of the integrated modeling approach and helps support a more accurate comparison of program-level and investment-level benefits across DTE's portfolio. It should be noted that if the sequencing is changed, the BCA for an investment activity on a circuit would change and could potentially drive different decision-making. For instance, DA may not be beneficial to include on a circuit since vegetation management and PTMM provide significant improvement to vegetation and equipment based outages. If the vegetation management program is significantly altered, it may now be beneficial to add DA to that circuit. DTE should continue to evaluate whether investment decisions regarding these programs change when the activities of other programs are modified.

1.1.5 Grid Automation Telecommunication Updates

The Grid Automation Telecommunications BCA was refined from 2025 to 2026. In the 2025 analysis, 1898 & Co. evaluated a broader set of global telecommunications scenarios, including the current communications system, Public Cellular and Private Cellular under both current-capacity and expanded-use-case conditions, with the purpose of identifying the preferred long-term system-wide or "North Star" solution and evaluating specific fiber investments based on that preferred solution.

In the 2026 BCA, the approach was refined to a direct least-cost comparison between two primary long-term alternatives: Public Cellular and Private Cellular supported by fiber backhaul. The updated analysis evaluated those alternatives under High, Likely, and Low device-growth scenarios and excluded Distribution Automation benefits so the communications evaluation would isolate network-related costs and avoided costs. The conclusion was similar to the 2025 analysis: the private communications solution continued to be the preferred long-term strategy because it produced the lower life-cycle cost and better supports future grid modernization needs.

In the 2026 analysis the fundamental approach to performing the BCA for fiber routes remained aligned with the 2025 BCA. The 2026 results show that the fiber route investments support the broader "North Star" strategy, in that most route-level

investments are economically supportive of the Private Cellular/Fiber platform while also enabling the longer-term expansion of grid communications capabilities across the system.

1.1.6 Distribution Automation Updates Impact Overview

The modeling approach used for the 2025 BCA was leveraged for the 2026 BCA, and the approach did not materially impact the results for the 2026 BCA. However, key inputs such as the ICE calculator and program sequencing did have a significant impact on the Distribution Automation (DA) BCA. Both changes represent shifts towards a more conservative modeling approach, thus reducing the monetized benefits available when considering deploying DA solutions.

In the 2025 BCA, the total investment was estimated at approximately $1.03 billion, with an aggregate Benefit-Cost ratio (BCR) of 3.56. Approximately $830 million or 80.6% of the investment showed benefits in excess of costs. These results reflect a modeling approach in which DA benefits were evaluated largely in isolation, with limited interaction effects from other programs explicitly incorporated into the baseline. Additionally, the 2025 analysis utilized ICE 1.0 for the monetization of customer outages. As Section 1.1.3 describes the change from ICE 1.0 to ICE 2.0 is impactful for C&I customers. Avoided C&I outages are a major benefit stream for distribution automation since most of these customers are directly served from circuit backbones that DA is designed to improve.

In contrast, the 2026 analysis shows a materially different Resilience, Reliability, and Risk BCR profile for the DA program. The total investment decreases to approximately $868 million, and the aggregate BCR is reduced to approximately 1.37, with $380M or 43.8% of the investment producing benefits with a BCR ≥ 0.9. The aggregate BCR for deploying this program on circuits where the BCR ≥ 0.9 is 2.71.

The ICE calculator's valuation of C&I customers and the assumption that vegetation management and PTMM occur before DA reduce the Avoided CMI$ that can be attributed to the DA program. In addition, the Benefit-Cost Analysis for this program

needs additional context for investment decision purposes, mainly the conservative nature of the analysis:

- It is rooted in historical outage data and does not consider the full universe of weather events captured in the Resilience modeling approach, therefore, future outages could be higher than what is currently considered.
- It assumes a fuse blowing protection strategy instead of fuse saving. Because of this the avoided outages of this program are underrepresented.
- It does not capture many indirect benefits of the DA programs (e.g., more crews' time made available for restoration from faster line patrol and failure identification, and avoiding manual switching operations to adjacent circuits and substations, etc.)
- The discounted cash flow is only applied to the first 20 years of the recloser asset life, which generates lower present value of the benefits than taking the entire asset life of reclosers (30 years) into the analysis.
- A conservative customer outage economic cost valuation from ICE 2.0. As Section 1.1.3 notes, the C&I benefits could be underestimated by as much as 50 percent. Given the mix of customers on backbones, utilizing the ICE 2.2 calculator could significantly increase the benefits on DA projects. 1898 & Co. estimates that it could increase these benefits by 25 to 40 percent for many circuits.

While the DA program's level of investment quantified benefits decreased from 2025 to 2026, the analysis in both years shows that investing in distribution automation is significantly beneficial for DTE's customers. As this program matures and the evaluation approach is enhanced to account for the conservative nature of the evaluation described above, 1898 & Co. expects the level of investment for this program to expand for the benefit of DTE customers.

1.2 Resilience, Reliability, and Risk-Based Planning Approach

1898 & Co. utilized a resilience, reliability, and risk-based planning approach to identify and prioritize potential investments and perform a Benefit-Cost Analysis to

support the investment justification for the investment programs outlined above. The planning approach utilizes a suite of planning models and the Integrated Resilience, Reliability, & Risk Investment Model developed by 1898 & Co. For the purposes of this evaluation, resilience, reliability, and risk benefits for investment activities are estimated from a customer-centric perspective. The customer benefits are shown in terms of the following:

1. Decrease in utility restoration costs; and
2. Decrease in the number of customers impacted and in the duration of the overall outages, calculated as CMI and monetizing the CMI.

From these benefit streams, the model calculates the resilience, reliability, and risk BCR for each investment activity, circuit, substation (where appropriate), and program.

$$Resilience, Reliability, \& \ Risk \ BCR = \frac{Lifecycle \ PV \ Avoided \ Reactive \ Costs + Lifecyle \ PV \ Avoided \ \$CMI}{Lifecyle \ PV \ of \ Investment}$$

The Resilience, Reliability, & Risk BCR, as used in this analysis, is a single value that represents complex modeling of resiliency and reliability failure modes (including Major Event Day type outages), infrastructure vulnerability, infrastructure rebuild costs, and other financial factors to provide a robust and reliable measure to evaluate individual investments from a quantified customer benefit perspective.

This single value, Resilience, Reliability, & Risk BCR, for each circuit, substation, and program level constitutes a sophisticated multi-factored analysis. The results of this evaluation are measured at the circuit and/or substation level to align with DTE's execution approach. The Resilience, Reliability, & Risk BCR incorporates the following factors for each investment activity associated with each program:

Resiliency & Reliability Failure Modes & Events

- Range of resiliency events.
- Frequency of those resiliency events.
- Location of events by county.

- The expected asset-level probability of failure is based on expected equipment lives and types of failures.
- Expected Impact to customers, customer minutes interrupted, is based on historical customer impacts.
- The decrease in customer outage impacts for DA is directly estimated from historical outage records.

Infrastructure Vulnerability

- Number of assets within each investment activity.
- Age of the assets within each investment activity and their expected lives.
- Known equipment original design vulnerabilities (e.g., Cellon-treated poles).
- Vegetation density around each span of conductor.
- Number of downstream customers impacted for each investment activity.
- Types of customers (residential, commercial & industrial (C&I) grouped into 20 different bins based on usage) for each investment activity; and
- The accessibility of the infrastructure in terms of street access.

Infrastructure Rebuild Costs

- The investment needed to mitigate the resilience, reliability, and risk events, including:
  - Type of assets,
  - Number of assets, and
  - Location of the assets (rear lot/front lot).

Financial Factors

- Discounted cash flow methodology over the life-cycle of the infrastructure, shown in Table 4-1.
- The Interruption Cost Estimator (ICE) 2.0, phase 1, calculator (see Section 4.2) to evaluate the cost of an outage for the range of customer types and outage durations.

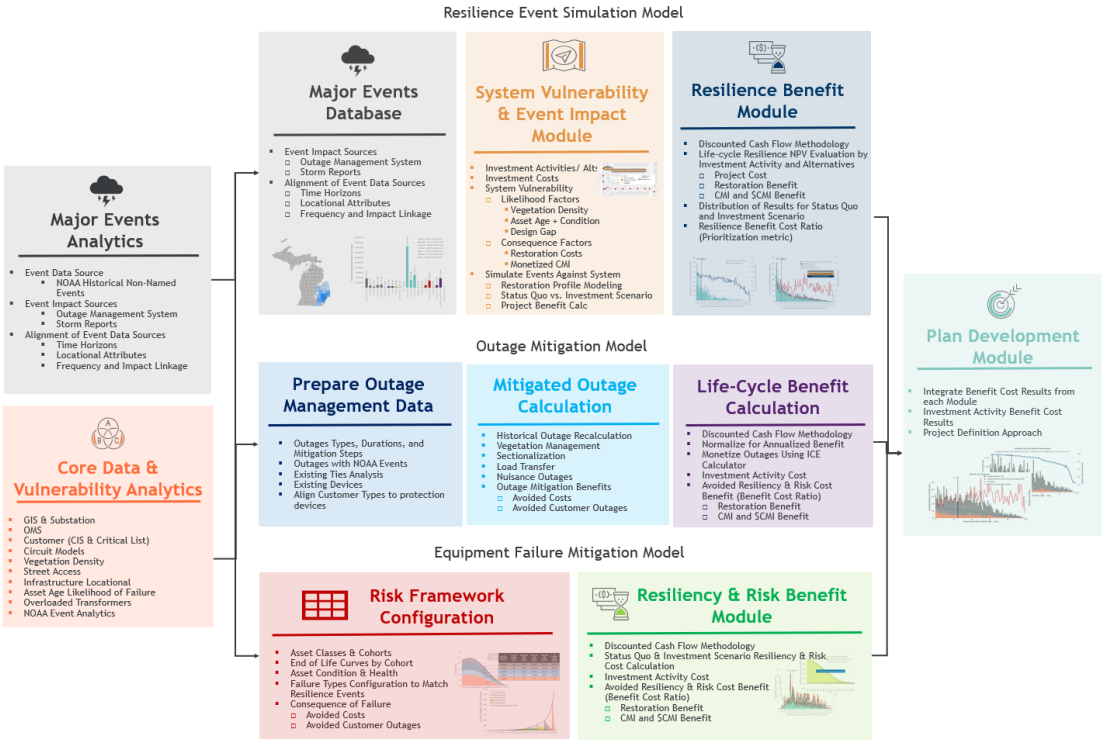
1898 & Co. has carefully integrated all these factors within each model to estimate benefits objectively, consistently, and precisely for each investment activity. **This**

approach makes the BCR value a robust and reliable measure to help understand the justification for investment activities. This multi-factored and quantified benefit metric provides confidence that investments will provide benefits in excess of costs for customers. This value is thus an appropriate metric to guide investment selection and justification on the DTE system.

The Resilience, Reliability, & Risk BCR captures many, but not all, benefit streams. The above list illustrates the breadth of factors quantified in the BCR assessment. However, 1898 & Co. recognizes that other difficult-to-quantify risk factors also influence investment selection and prioritization. Key qualitative factors include safety, areas of lower performance (e.g., Customers Experiencing Multiple Interruptions or CEMI), and cyber-security risks, including the risk that new regulations require additional cyber-security investment. To account for qualitative benefits that are not directly quantified in a BCR, 1898 & Co. uses a BCR ≥ 0.9 threshold for justification of investment. The Resilience, Reliability, & Risk BCR is an important tool for justifying investments. However, other, less-quantifiable, factors must also be considered. Integrating quantitative and qualitative assessments provides a more powerful decision-making tool for utility investments.

Figure 1-1 provides an overview of the Integrated Resilience, Reliability, & Risk Investment Model utilized within the DTE Benefit-Cost Analysis. The Integrated Resilience, Reliability, & Risk Investment Model employs a data-driven, decision-making methodology using sophisticated algorithms to calculate the resilience, reliability, and risk benefits for each potential investment activity that makes up each program.

Figure 1-1: Integrated Resilience, Reliability, & Risk Investment Model



The model first includes foundational data, including DTE's asset registers and equipment characteristics, which are used to determine the unique vulnerabilities of DTE's system. This information feeds the rest of the model.

The model includes two analytics models (Outage Mitigation Model and Equipment Failure Mitigation Model). Each analytics model estimates the expected avoided costs and avoided customer outages. Each analytics model was designed to estimate the resilience, reliability, and risk benefits of investments based on the available data, asset types, benefit streams, and failure types. This is further discussed in Section 4.0.

Finally, the model includes a plan development module that integrates the Benefit-Cost results from each analytics model and incorporates investment activity bundling approaches to support DTE's implementation planning. The output of this module is a list of investment activities that can help inform DTE's development of an executable plan.

1.3 Benefit-Cost Analysis Results Summary

Table 1-1 provides a summary of the Benefit-Cost Analysis (BCA) results for each of the programs evaluated by 1898 & Co at the program level. The table presents a high-level comparison of total benefits, total investment, and the cost-effectiveness of activities across the programs evaluated. Additional detail regarding each program is provided in Section 5.0.

Table 1-1: BCA Analysis Summary By Program[1]

Program	Total Benefits	Total Investment	Total Benefits BCR ≥ 0.9	Total Investment BCR ≥ 0.9	% of Investment with BCR ≥ 0.9	Weighted BCR of Activities BCR ≥ 0.9
PTMM Groundline	$7.77B	$2.97B	$7.7B	$2.86B	96.3%	2.69
PTMM Pole Top	$3.96B	$853.3M	$3.94B	$827.48M	97%	4.76
Small Wire Replacement	$5.67B	$5.25B	$4.58B	$2.39B	45.5%	2.09
Breaker Replacement	$1.58B	$2.29B	$967.21M	$857.27M	37.4%	1.13
URD Replacement	$1.54B	$3.63B	$447.55M	$420.58M	11.6%	1.06
Cable Replacement	$4.93B	$8.06B	$1.33B	$1.22B	15.1%	1.09
Subtransmission SCADA	$1.28B	$161.87M	$1.27B	$93.61M	57.8%	13.52
Distribution Automation	$1.19B	$868.46M	$1.03B	$380.14M	43.8%	2.71

The Communication Network program is an enabling, system-wide investment evaluated using a least-cost framework rather than a traditional benefit attribution approach. Reported benefits represent avoided life cycle costs relative to continued reliance on Public Cellular services, not direct reliability or operational benefits. Under the likely device growth scenario the total investment is $6.9 billion with a BCR

[1] All values are presented in life-cycle net present value 2026 dollars.

of 1.58. The results for High and Low device growth scenarios are presented in the Communication Network section 5.8.

The Subtransmission Redesign and Rebuild projects evaluated by 1898 & Co. represent a total investment of approximately $405 million. The results indicate that several projects provide strong quantified reliability and resilience benefits, while others address important capacity, operability, and safety needs that are not fully captured in the quantitative BCA. The 4.8 kV and 8.3 kV conversion projects represent a total investment of approximately $2.9 billion. For these programs, the analysis indicates that a majority of projects provide strong, quantified reliability and resilience benefits, while others provide value from improvements in operations, safety, and load-serving capability.

1.4 Conclusions

The results of the 2026 Benefit-Cost Analysis show that the evaluated programs include a substantial set of investments that are supported by quantified resilience, reliability, and risk-reduction benefits. The Integrated Resilience, Reliability, and Risk Investment Model used for this evaluation applied a consistent, data-driven framework to assess the customer and system benefits associated with distribution, subtransmission, substation, and communication network assets. The analysis quantified avoided customer outage impacts and avoided restoration-related costs and compared those benefits to the required investment on a program and project basis. The following summarizes the conclusions of the Benefit-Cost Analysis for the programs evaluated by 1898 & Co.:

- The resilience, reliability, and risk BCR value is a robust and reliable measure to help understand the justification for investment activities. **This multi-factored and quantified benefit metric provides confidence that investments will provide benefits in excess of costs for customers.** Additionally, the Benefit-Cost Analysis is comprehensive, consistent, customer-centric, data-driven, and practical.

- When compared to the previous 2025 BCA, the **2026 BCA expands both the scope of programs evaluated and includes additional modeling enhancements**. Specifically, it incorporates additional asset and outage data, applies updated interruption cost assumptions from ICE calculator 2.0, updates the unit costs of assets in previous programs, and introduces resilience-event simulation to capture the consequences of various weather events. The addition of the resilience model to the 2026 BCA improves the ability of the analysis to reflect the actual performance risks facing DTE's system and provides a robust basis for identifying investments that are expected to provide meaningful customer value.
- The 2026 BCA is enhanced through the incorporation of storm and resiliency modeling. Unlike the prior analysis, the **2026 BCA evaluates the impact of various weather events on DTE's system** by using historical NOAA weather data, DTE outage records, and simulation of future weather-event outcomes. The evaluation showed that nearly 80 percent of all historical customer minutes interrupted (CMI) directly mapped to an observed weather event. This addition allows the analysis to better capture the customer and system consequences of severe events, including long-duration outages and restoration challenges, and better quantifies the value of investments that reduce infrastructure vulnerability, improve system performance during weather events, and strengthens overall grid resilience.
- **The Pole and Pole Top Maintenance & Modernization program, similar to the conclusions from the 2025 BCA, is beneficial for DTE Electric customers and provides a significant opportunity to improve resiliency, improve reliability and manage safety risks on the system.** The modeling shows that over 96 percent of the potential investment for the distribution system has a BCR ≥ 0.9.
- The **Small Wire Replacement program** identified targeted circuits where benefits can be gained from improving the resilience and reliability of DTE Electric's overhead distribution system through targeted rebuilds of protection zones that contain qualifying small wire. The BCA shows that this program is beneficial for

DTE customers with nearly $2.4 billion of investment with a BCR ≥ 0.9 and an average BCR of 2.09.

- For the **Breaker Replacement, URD Replacement, and Cable Replacement programs**, the modeling was used to evaluate the benefits of proactively replacing aging and higher-risk infrastructure by estimating avoided customer outage impacts and avoided reactive restoration costs over the life of the assets. This is particularly important for system cable, which often serves dense load areas, critical infrastructure, and other high-impact customers where failures can be difficult to locate, labor-intensive to repair, and disruptive for long durations. The modeling identified specific parts of the system for potential investment that would benefit DTE customers, with nearly $2.5 billion of investment across the three programs with a BCR ≥ 0.9. In addition, each of these programs provide qualitative benefits not fully captured in the quantified BCA, including improved operability and maintainability, reduced safety exposure from reactive repairs, improved fault-clearing performance, and reduced risk of broader equipment damage or hazardous failure events.
- The **Subtransmission SCADA Program** demonstrated significant opportunity for customer value at specific locations where additional switching capability can improve the performance of DTE's subtransmission system. The subtransmission system serves as the critical link between the transmission network and the distribution substations that ultimately serve customers, and it is designed to provide redundancy through trunk and tie line configurations. By adding SCADA-enabled Automatic Pole-Top Switches, DTE can better isolate faults, leverage existing system redundancy, reduce outage duration, and lessen the customer impacts of high-consequence subtransmission outages. In that respect, the program supports both improved reliability and improved operational flexibility on a portion of the system where outages can affect large numbers of downstream customers.

The **DA Program** continues to provide meaningful customer value by reducing the impact of outages through increased sectionalization and automated switching on

DTE's distribution system. The 2026 BCA shows that the program remains beneficial and can materially reduce customer outage impacts. Relative to the prior analysis, however, the quantified Benefit-Cost results are lower due primarily to two factors: the transition from the ICE 1.0 to ICE 2.0 calculator, which reduces the monetized value of non-residential outages, and the integrated sequence of modeling assumption that vegetation management and PTMM have occurred before DA benefits are evaluated, which reduces the remaining incremental benefit available to the DA program. When considering the level of investment into this program, the conservative nature of the evaluation, and the expected changes with ICE 2.2, the benefits of this program could increase by 25 to 40 percent for most circuits. As this program matures and the evaluation approach is enhanced to account for the conservative nature of the evaluation described above, 1898 & Co. expects the level of investment for this program to expand for the benefit of DTE customers.

- The **Subtransmission Redesign and Rebuild Program and the 4.8 kV and 8.3 kV Conversion Programs** include critical projects that address aging infrastructure, improve switching and restoration capability, strengthen system operability, and support future load growth. Many of the projects have proven to be cost effective by the monetized BCRs alone. Yet all the projects analyzed provide important tangible, qualitative benefits to DTE customers.
    - For the Subtransmission Redesign and Rebuild Program specifically, those additional benefits include improved operational flexibility, greater ability to isolate faults and transfer load including N-1 contingency events, improved maintainability, reduced exposure to vegetation-related outages where facilities are relocated to more accessible corridors, enhanced crew safety, and reduced risk of catastrophic equipment failures on backbone facilities that can interrupt service to large portions of the system. In that respect, these projects should not be viewed solely through their quantified BCR results, because they also support DTE Electric's obligation to provide safe, reliable, operable, and resilient electric service.

- For the 4.8 kV and 8.3 kV Conversion Programs, additional qualitative benefits include improved public and worker safety through the reduction of risks associated with aging legacy equipment and downed energized conductors, simplification and standardization of system operations and maintenance, improved voltage performance and capacity, and enhanced ability to accommodate future load growth, electrification, and distributed energy resources. In that respect, these projects should not be viewed solely through their quantified BCR results, because they also support DTE's obligation to provide safe, reliable, operable, and resilient electric service.

- The **Communication Network** analysis supports a clear long-term strategic direction. The evaluation indicates that a Private Cellular solution supported by fiber backhaul represents the lowest life-cycle cost communications strategy relative to reliance on Public Cellular service. This conclusion is consistent across the modeled growth scenarios and reflects the long-term cost advantage of utility-managed communications infrastructure when compared to large, recurring carrier fees, risk in sharing the network with the general public, and replacement cycles that are out of DTE's control. The fiber routes analyzed to support communications infrastructure serves as a critical foundational component of this strategy by providing high-capacity, low-latency, and highly reliable backhaul connectivity between substations, communication nodes, and control centers. In addition to the quantified cost advantage, this strategy positions DTE to support future grid modernization requirements through a more scalable, secure, and operationally aligned communications platform.

- **Many of the programs will benefit all DTE customers**. The nature of the many of the programs is widespread across the entire DTE system. The avoided reactive and investments costs are shared by all distribution customers. Additionally, distribution customers will experience fewer storm outages from both direct and indirect factors. Direct benefits are realized by those customers whose infrastructure is located directly downstream of the resiliency investment. Indirect benefits are realized by all distribution customers since

storm restoration crews will be able to rebuild the system quicker because less infrastructure will fail.

- **The investment benefits are conservative**. First, the use of the ICE Calculator is conservative as the BCA utilizes the ICE 2.0 calculator. A recent update to the calculator, ICE 2.2, shows the cost of interruptions for DTE's C&I customers is approximately 50 percent higher for most outage durations. Second, the quantified evaluation only considers direct benefits to events and does not factor in the indirect benefits from lower overall storm restoration durations. Third, the quantified benefit-cost assessment has carefully included the full cost of implementing investments; however, the full level of benefits has not been captured. Specifically, the evaluation has not incorporated qualitative benefits associated with safety, mitigating cyber risk, or service improvement in areas of lower performance where quantified benefits are not in excess of cost.

Overall, the 2026 BCA concludes that DTE's proposed set of programs and investment levels include investments that are both economically justified and strategically aligned with long-term system needs. While not all individual projects yield quantified benefits above a BCR ≥ 0.9, the combined portfolio, supported by both quantitative results and qualitative considerations, provides substantial value to customers through improved reliability, reduced outage impacts, enhanced safety, increased system resilience and enhanced system operability to meet customer expectations, future load growth and DER integration, while maintaining or reducing customer costs.

2.0 Core Data and Analytics

The resilience, reliability, and risk-based planning approach and methodology is data-driven. This section outlines the core data sets and base algorithms employed within the Integrated Resilience, Reliability, & Risk Investment Model. A connectivity model is established that allows for the linkage of the foundational data sets: Geographical Information System (GIS), Outage Management System (OMS) and Customer Information data. Additionally, the connectivity model builds on the foundational data set asset-level attribute understanding by utilizing models that:

1) estimate conductor level vegetation density,
2) determine age of assets,
3) analyze pole inspection rejection rates, and
4) determine accessibility of assets for the entirety of the system.

The 1898 & Co. analytics engine then transforms the data connectivity model into the data model needed to perform the risk and reliability analytics.

2.1 Asset Base

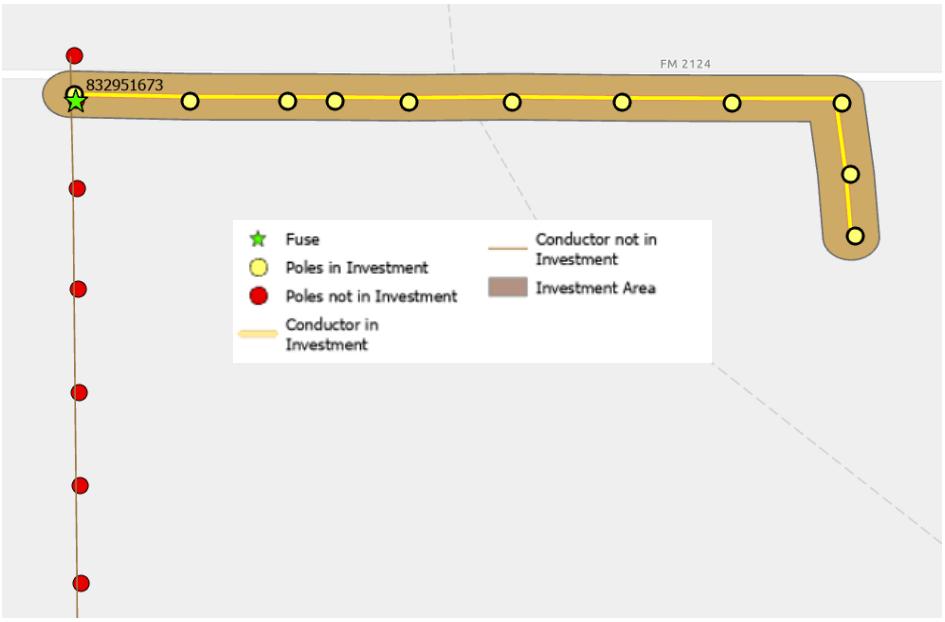
This section describes the asset foundation used in the model, including the GIS-based system inventory, the linkage of assets to protection zones, and the overall scale of the distribution, subtransmission, and substation assets evaluated. Establishing this asset base is a critical step in the bottom-up methodology because it defines the physical system being analyzed and creates the structure needed to connect asset condition, failure consequences, and customer impacts. The following subsections summarize how assets were identified, organized, and mapped within the modeling framework.

2.1.1 GIS Data

GIS provides the list of circuit assets in DTE's system and how they are connected to each other. Since the planning approach is fundamentally a bottom-up asset management methodology, it starts with the asset data, then rolls all the assets up to protection zones (a collection of assets that directly impact customers), and

protection zones to circuits and substations. The relationship between assets and protection zones is illustrated in Figure 2-1 below.

Figure 2-1: Asset to Protection Zone Relationship



In alignment with this methodology, 1898 & Co. utilized the connectivity within DTE's GIS and distribution circuit models to link each distribution voltage asset to a lateral (typically a fuse protection device) or feeder (typically a breaker or recloser protection device) to establish discrete protection zones. The asset to protection zone linkage is foundational to the 1898 & Co. modeling approach. Each protection zone includes a set of assets that service downstream customers from the protection device. If any assets in the protection zone were to fail, all the downstream customers would be impacted. This allows for the direct alignment between assets and customers.

2.1.2 Distribution, Subtransmission, and Substation Asset Base

Through this approach, 1898 & Co. was able to use the asset-level information and map it to over 89,000 protection zones on the system where applicable. By organizing the analysis at the protection-zone level, the model can directly connect asset condition and performance to potential customer impacts, which supports a detailed system evaluation. Table 2-1 below displays the assets that were mapped and

analyzed in 1898's analysis. The substation asset base includes key information such as equipment type, position within the substation, asset age, and other supporting attributes.

Table 2-1: DTE's Mapped Asset Base Used in BCA

Asset Type	Units	Value
OH Distribution Primary Conductor	[miles]	28,111
OH Subtransmission Primary Conductor	[miles]	2,572
System Cable	[miles]	2,456
URD Cable	[miles]	10,656
Distribution Mainline Poles (Breaker/Recloser)	[count]	257,206
Distribution Lateral Poles (Fuse)	[count]	603,287
Subtransmission Poles	[count]	84,925
Substation Breaker[2]	[count]	5,228

2.2 Outage Management System

The OMS includes detailed outage information by cause code for each protection between January 1, 2007, to Dec. 31, 2025. DTE provided this dataset, which includes outage causes, durations, CI, CMI, dates, and locations for over 1,000,000 outage events.

As with most utility outage management system records, DTE's OMS data contains some limitations in completeness and consistency, including instances where outage causes or device types were not identified or recorded. Based on 1898 & Co.'s experience reviewing outage management system data across many electric utilities, these types of data limitations are common and are influenced by field conditions, business processes, and historical recording practices. 1898 & Co. observed that DTE's outage data quality has generally improved over time, with more recent records demonstrating greater completeness and consistency than older records. 1898 & Co.

[2] Includes both breakers and substation reclosers.

determined that the OMS data was sufficient for use in the Integrated Resilience, Reliability, & Risk Investment Model.

The Integrated Resilience, Reliability, & Risk Investment Model utilized this information to understand the historical weather-related outages for the various distribution laterals and feeders on the system. The OMS data is utilized by the Outage Mitigation Risk & Resilience model to identify outages that can be mitigated by investments in distribution automation. It is also used to understand failure types and restoration times utilized in the Equipment Failure Mitigation Modeling approach.

2.3 Customer Information Data

DTE provided customer count and customer type information with relational links to the GIS and OMS databases. This data enabled 1898 & Co. to identify the count and type of customers that would be impacted by a failure in each distribution protection zone and subtransmission circuit. The customers served by each substation were also established by using connectivity from the distribution circuit to the substation protection device (breaker or substation recloser). In cases where customers could not be linked to substations through direct relationships, unmatched customers were allocated within each substation to the remaining distribution circuit-protecting devices.

This data allowed the Integrated Resilience, Reliability, & Risk Model to link the number and type of customers impacted to each distribution protection device, circuit, and substation. This customer information is used with the estimated event and failure duration to estimate the CMI for each investment activity, which is then monetized using the ICE Calculator (see Section 4.2). This is foundational for the customer-centric Benefit-Cost assessment.

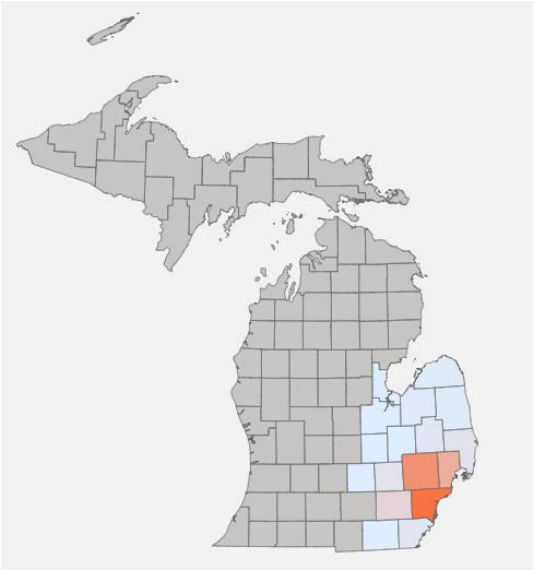
The tables and figures below provide a summary of the customers across DTE's system that 1898 & Co. mapped to assets for this analysis. Table 2-2 shows the total mapped customer count by type, and Figure 2-2 shows a geospatial representation of customer locations across the DTE service area. These customers were derived from our mapping using CYME models and customer-to-protection device ID linkages, with protection devices subsequently mapped to system assets; as a result, some

customers are not included due to gaps or inconsistencies in these linkages. The figure shows a heavy representation of customers in the Detroit metropolitan area, including Wayne, Oakland, and Macomb counties.

Table 2-2: DTE's Mapped System-wide Metered Customer Breakdown

Customer Type	Customer Count	Percentage
Residential Customers	2,049,796	91.56%
Commercial & Industrial Customers	189,007	8.44%
Total	**2,238,803**	**100.0%**

Figure 2-2: Relative Customer Count Across DTE's System



As described in Section 2.1.1, the approach organized distribution assets at the protection zone level. For each protection zone, 1898 & Co. identified the number and type of downstream customers that would be impacted by a failure within that protection zone, based on the database relationships described above.

The following figures present the distribution of customer counts and types across all circuits (Figure 2-3), distribution protection zones (Mainline Zones in Figure 2-4 and Lateral Zones in Figure 2-5), and substations (Figure 2-6).

Figure 2-3: Metered Customer Count and Type by Distribution Circuit

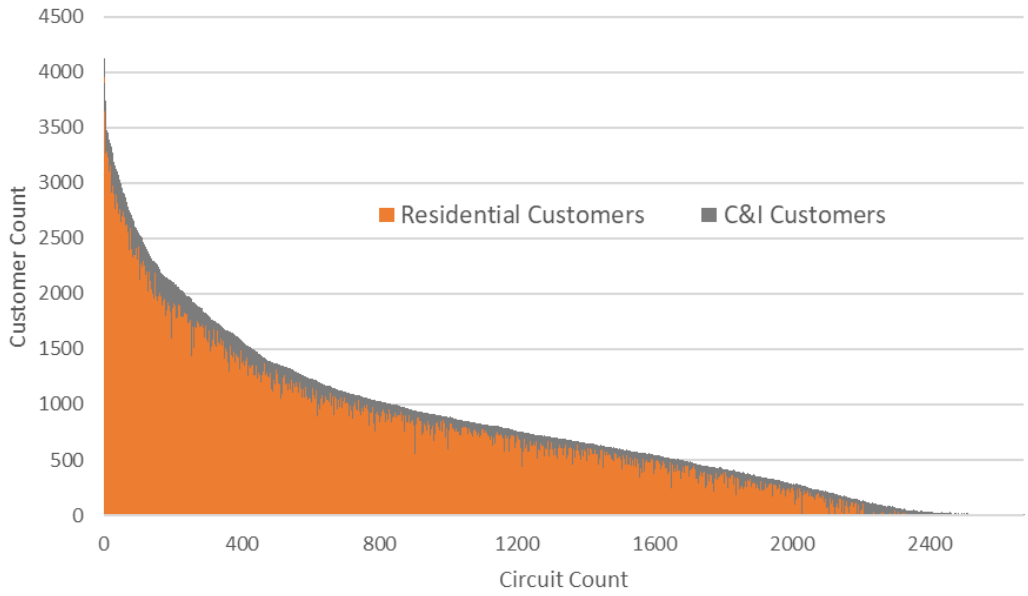
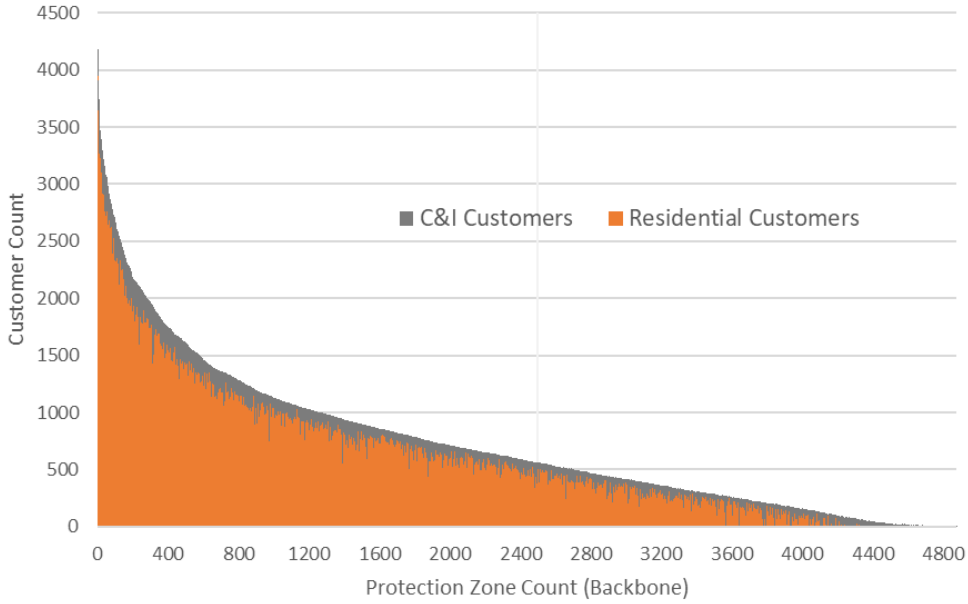


Figure 2-4: Metered Customer Count and Type for Distribution Mainline[3] Protection Zones



[3] Includes breaker and mainline recloser protection devices.

Figure 2-5: Metered Customer Count and Type for Distribution Lateral[4] Protection Zones

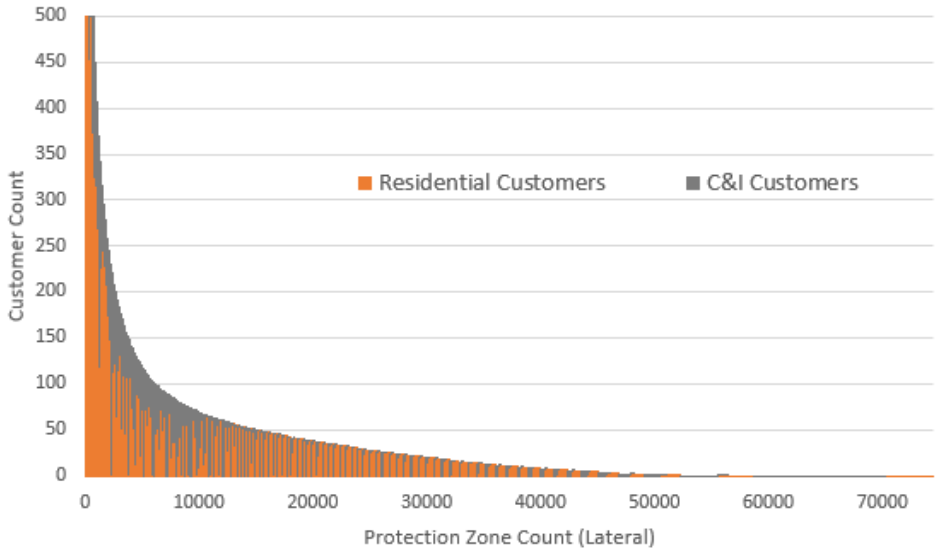
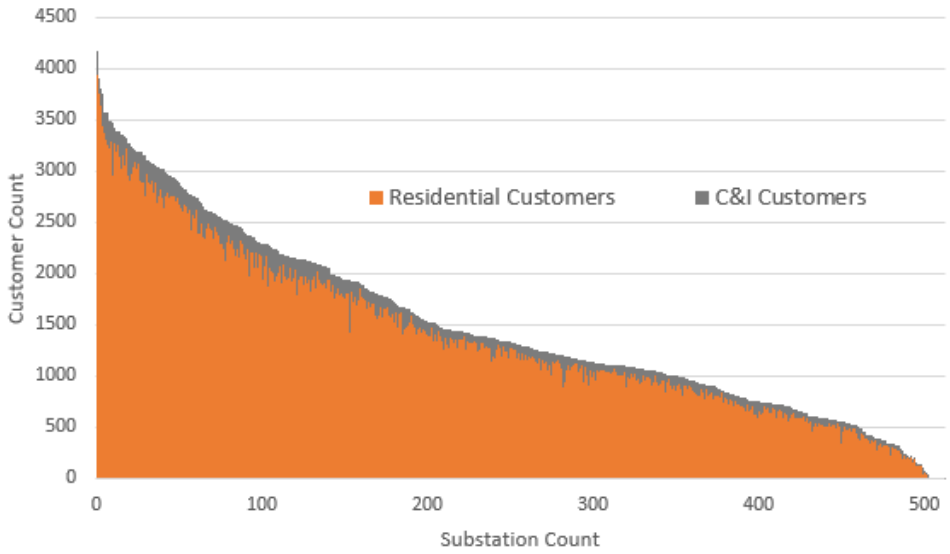


Figure 2-6: Metered Customer Count and Type for Substations



[4] Fuse or Lateral Recloser Protection devices

2.4 Vegetation Density

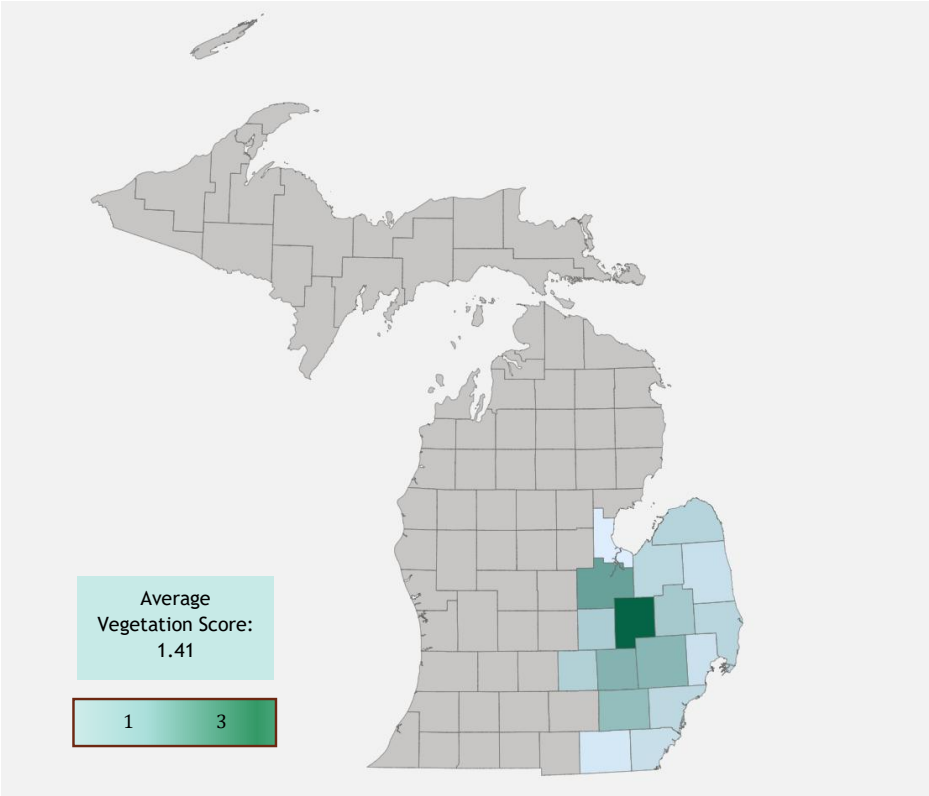
The vegetation density for each overhead conductor is a core data point for identifying and prioritizing investment for circuit assets. Poles that are in high vegetation areas are subject to more life-cycle stresses over their life-cycle than poles in low vegetation areas. The life-cycle stresses impact the expected life and increase the likelihood that poles or pole tops may fail. The Integrated Resilience, Reliability, and Risk Model estimates the vegetation density around each distribution overhead conductor. The model utilizes satellite tree-canopy data to calculate the percentage of vegetation for 30-meter by 30-meter (900 square-meter) areas across the entire DTE system. The 900 square-meter area is indicative of the vegetation density on the system from a major storm perspective. For each of the approximately 1 million spans of conductor on DTE's system, a vegetation density is assigned based on the 900-square-meter area(s) the conductor spans through. The evaluation only considers the space that is 20 feet on either side of the conductor.

Figure 2-7 illustrates vegetation density for distribution primary assets mapped geospatially across county sections. To support comparison across the system, the modeled vegetation density values were converted to a vegetation density score on a scale of 1 to 5, where higher scores indicate greater vegetation exposure. Scores were assigned based on the underlying vegetation density percentage as follows:

1) 0% to 20% corresponds to a score of 1,
2) 20% to 40% corresponds to a score of 2,
3) 40% to 60% corresponds to a score of 3,
4) 60% to 80% corresponds to a score of 4, and
5) 80% to 100% corresponds to a score of 5.

On the map, darker shading indicates a higher vegetation density score and therefore a higher relative level of vegetation exposure, while lighter shading indicates lower vegetation density scores. As shown in the figure, the highest vegetation density scores are concentrated in a limited number of county sections, while much of the system falls within lower-scoring ranges.

Figure 2-7: Average Vegetation Density Across DTE's System



2.5 Asset Age

As assets age, they lose some of their original design strength and capability. For example, aged poles, when all else is equal, will fail at lower dynamic load levels than poles with their original design strength. The same concept applies to other overhead, underground, and substation assets. To account for this effect, the 1898 & Co. analysis utilized industry-standard survivor curves together with each asset class's expected average service life and each specific asset's age to estimate the age-based likelihood of failure. Asset ages were extracted from DTE's enterprise data systems for each asset class.

Table 2-3 summarizes the system average age end of life for the major asset classes included in the analysis. This comparison provides a system-level view of how the average age of each asset class relates to its expected life and helps illustrate which asset groups are, on average, closer to later-life condition states. This information

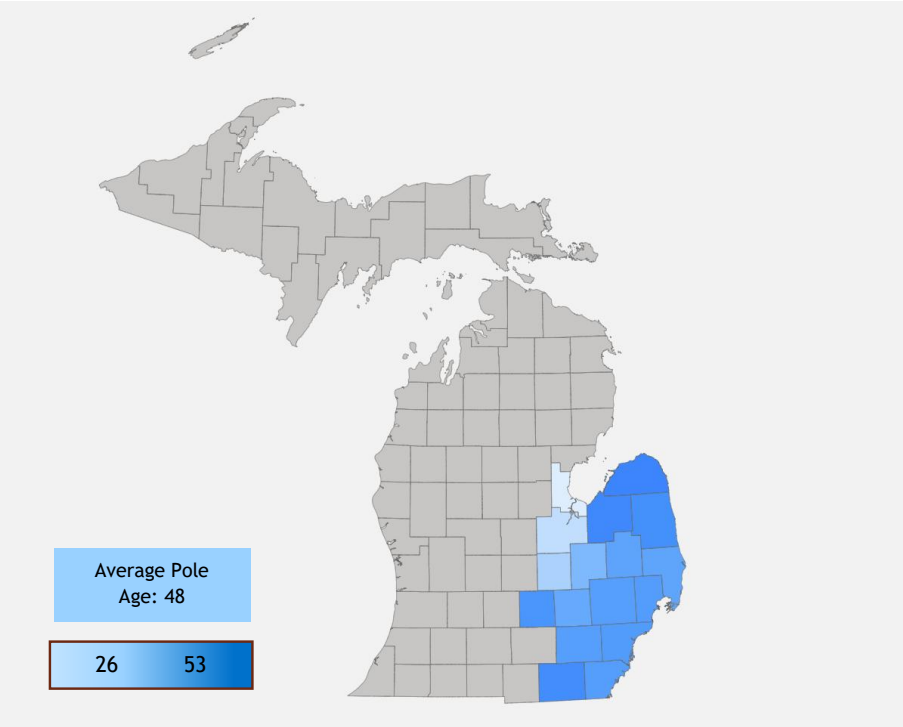
provides important context for how age-related vulnerability was incorporated into the failure modeling.

Table 2-3: DTE System Average Age

Asset Type	System Average Age
OH Distribution Primary Conductor	55
OH Subtransmission Primary Conductor	55
System Cable	53
URD Cable	27
Distribution Poles	48
Subtransmission Poles	46
Breakers	51
Substation Reclosers	43

Figure 2-8 illustrates the geographic distribution of average distribution primary pole age across DTE's service territory. While Table 2-3 provides a system-level summary, this figure shows how pole age varies spatially across the service area and highlights areas with relatively older or younger pole populations. This geographic view provides additional context for understanding how age-related vulnerability differs across the system. The heat map reflects the average age of distribution primary poles within each county, rather than the age of the oldest pole in each county. As shown, pole ages vary across the system, with the lowest county-level average pole age equal to 26 years and the highest county-level average pole age equal to 53 years.

Figure 2-8: DTE's Distribution Primary County Average Pole Age



2.6 Pole and Pole-Top Maintenance & Modernization Failure Rate Analysis

Pole inspections play a crucial role in maintaining the reliability and resilience of the power grid. Inspections help utilities understand whether or not poles can withstand environmental factors, including extreme weather conditions. This proactive, inspection-based approach enhances the overall resilience and reliability of the power grid, reducing the likelihood of service interruptions and improving the continuous delivery of reliable electricity to communities.

2.6.1 Background & Program Description

This failure-rate analysis was a continuation of work from the previous 2025 rate case. In the previous effort, 1898 & Co., in collaboration with DTE, developed a spreadsheet-based tool that produced circuit-level, PTMM-failure rate results by grouping assets into broad cohorts.

In this subsequent analysis, 1898 & Co. developed a more-granular, asset-level approach, derived from the more-detailed and more-recent inspection results that

DTE provided. Both theoretical and empirical evidence indicated a strong relationship between an asset's age and its probability of failure. This analysis disregarded any inspection result for which an asset age could not be determined.

2.6.1.1 Ground Line Inspection Program

As with the overall population of poles across the DTE system, the great majority of inspected poles were 90 years old or younger. For this analysis, 1898 & Co. developed groundline probability-of-failure (POF) rates after excluding inspection results for the small number of poles that were more than 90 years old at the time of inspection. When applying the POF rates to the full population of DTE poles, 1898 & Co. assumed that the failure rate for a 90-year-old pole was suitable for all poles older than 90 years.

2.6.1.2 Pole-Top Inspection Program

The more-recent pole-top-inspection results included no age data for the pole tops. Therefore, the pole-top-failure rate development relied upon the age of each pole top's associated pole.

2.6.2 Groundline and Pole-top Asset Evaluation

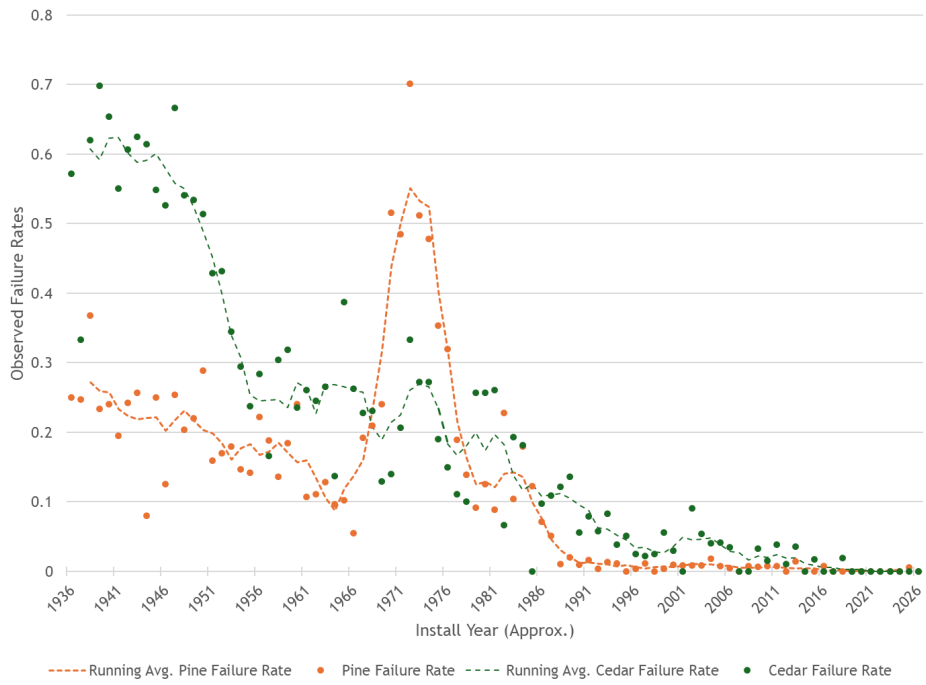
This section provides background on the asset data and an evaluation of the inspection results, beginning with the groundline inspections for the poles.

2.6.2.1 Groundline

In the evaluation, age was a strong predictor of pole failure. However, wood type was also a strong predictor. Based on DTE system data, 99% of the wood poles were either pine or cedar. Figure 2-9 illustrates the observed inspection failure rates for pine and cedar poles, with dots representing single-year rates and dashed lines representing failure rates over a five-year rolling window. The figure indicates that:

- Failure rates tended to be higher for older poles, compared to younger poles,
- Failure rates tended to be higher for cedar poles, compared to pine poles,
- There was a large increase in pine-pole failures rates among those poles installed during (approximately) the 1970s.

Figure 2-9: Groundline Inspection Failure Rates



2.6.2.2 *Cellon Treatment*

For this evaluation, DTE provided background information to enable better understanding of the large increase in pine-pole groundline-inspection failures among those poles installed during the 1970s. Over a long period of time, DTE (like many other utilities) had installed pine poles treated with Cellon for the purpose of extending the life of the poles. The greatest share of these Cellon-treated poles had installation years in and around the 1970s. Based on indications from DTE and the failure rate observations, it appeared that Cellon-treated, pine poles failed inspection at a higher rate than did non-Cellon-treated, pine poles.

2.6.2.3 *Pole Tops*

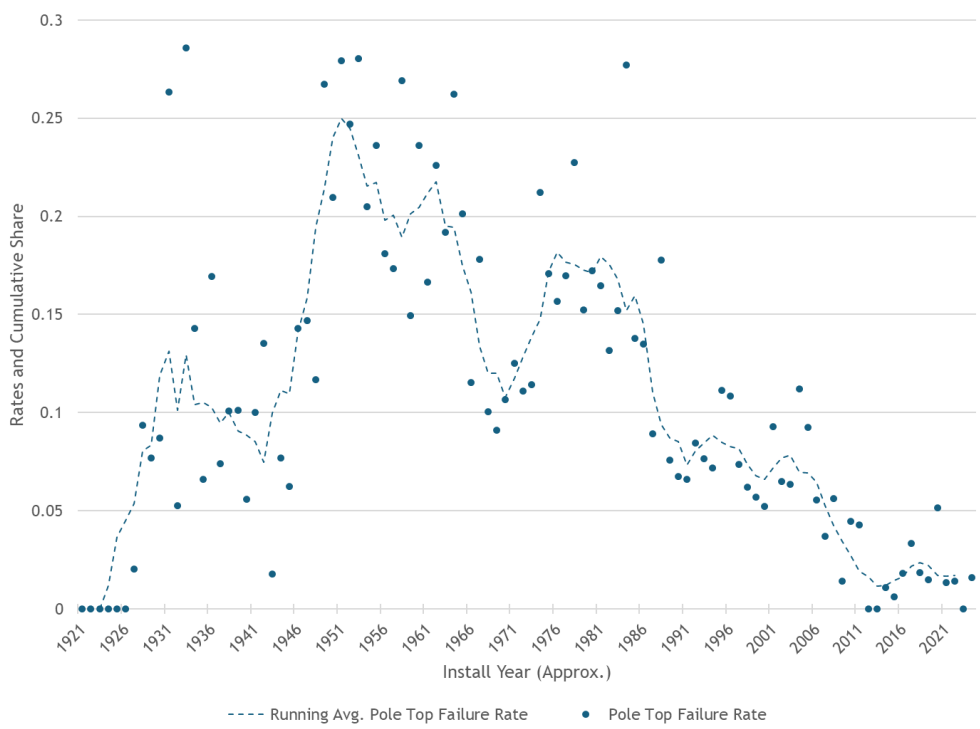
Figure 2-10 illustrates the observed pole top inspection failures, with dots representing individual-year failure rates and the dashed line representing a rolling five-year average. Unlike with the groundline inspections, the pole top failure rates did not, in general, decrease steadily with decreasing pole age. Instead, the pole top failure rates exhibited three ranges, each with a seemingly distinct failure-rate trend. Those ranges were, approximately:

1. Pole tops on poles installed before 1950.
2. Pole tops on poles installed between 1950 and 2009.
3. Pole tops on poles installed after 2009.

When considering Figure 2-10, possible explanations, though not fully explored, for these ranges include:

- Poles installed before 1950 generally had low pole top failure rates. This is likely because the original pole tops installed with these poles had previously failed and, therefore, the poles had newer, younger, replacement pole tops.
- Poles installed between 1950 and 2009 generally had a steady increase in pole top failures with increasing pole age, since the pole tops were standard across that range of pole-install dates and few poles had received replacement pole tops.
- Poles installed after 2009 generally had a very low pole top failure rate. This is likely due to the age and design basis of these younger poles and pole tops.

Figure 2-10: Pole Top Inspection Failure Rates



2.6.3 Analysis Method and Results

To model and evaluate the inspection-based failure of poles over time, 1898 & Co. developed POF models using logistic regression. A key application of logistic regression is predicting the probability of some binary outcome, based on certain input conditions. The binary outcome for this analysis was inspection pass-or-fail, while the input conditions were pole age and other factors described later in this section.

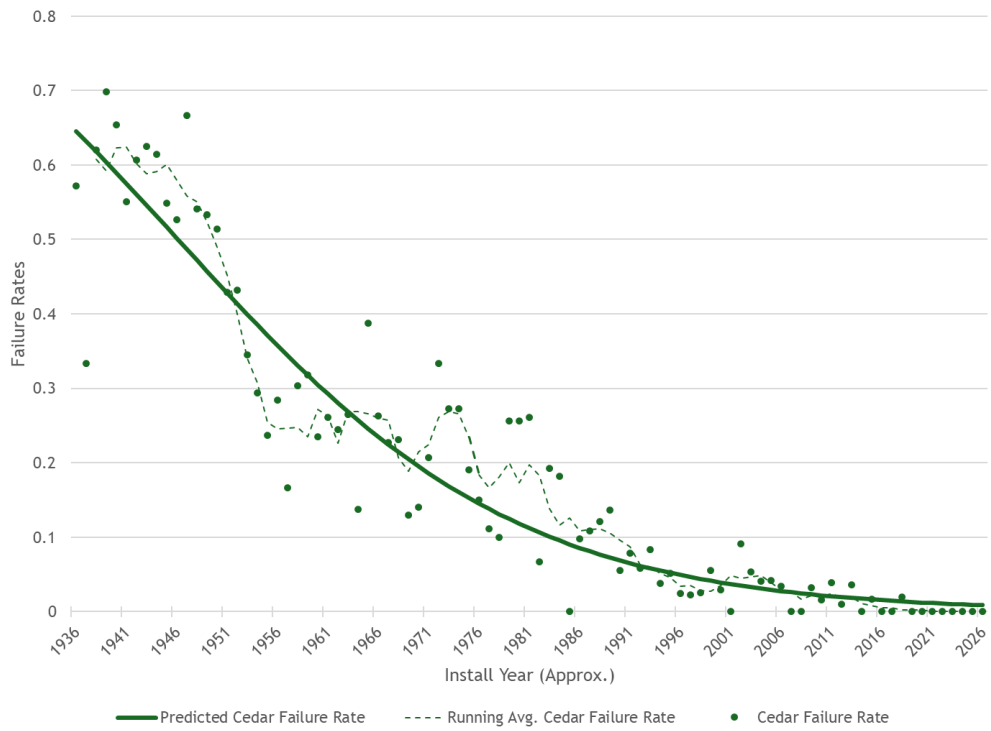
2.6.3.1 Groundline

This section describes the POF development for cedar poles and then for pine poles.

Cedar Pole POF Development

For the simple, cedar-pole case, pole age was the only input condition. The logistic regression produced a smooth POF curve that decreased from a 65% failure rate for poles installed in 1936 to a less than 1% failure rate for poles installed in 2026. As expected, the POF curve closely followed the observed failure rates. Figure 2-11 shows the predicted failure rate curve for cedar poles, along with the observed rates shown previously in Figure 2-9.

Figure 2-11: Cedar Pole Predicted Failure Rate

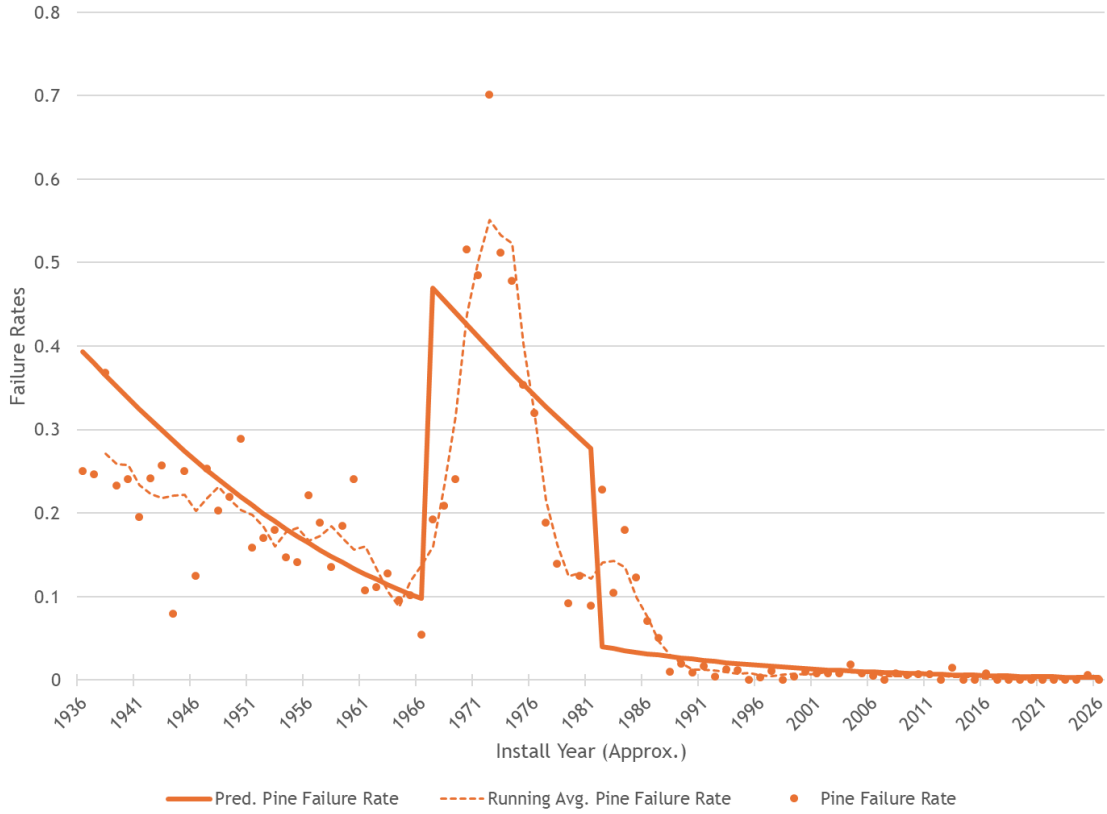


Pine Pole POF Development

The elevated observed-failure rate for pine poles installed in and around the 1970s required the introduction of a second input condition for the pine-pole regression. The second input was a binary value to indicate whether the pole's install year fell within a period of high Cellon-pole installation. Figure 2-12 shows the predicted failure rate curve for pine poles, along with the observed rates previously shown in Figure 2-9.

The pine-pole POF curve can be thought of as a single continuous curve, with the middle portion shifted upward to account for the increased failures among Cellon-treated poles.

Figure 2-12: Pine Pole Predicted Failure Rate



2.6.3.2 Pole Top

Previous sections detailed the difficulties associated with predicting pole top failures using pole age. Despite those difficulties, the available data supported POF development for pole tops after separating the pole tops into three groups based on the associated pole age. Recall these groups were:

- Pole tops attached to poles installed before 1950.
- Pole tops attached to poles installed between 1950 and 2009.
- Pole tops attached to poles installed after 2009.

Figure 2-13 shows the predicted pole top failure rates, with the observed rates previously shown in Figure 2-10.

Figure 2-13: Pole Top Predicted Failure Rate

2.6.4 PTMM Failure Rate Analysis Conclusions

This analysis produced data-driven POF curves that enabled the estimation of PTMM program costs and benefits, which are explained further in Section 5.1 below. In general, each curve exhibited the expected relationship between asset age and physical failure, with older assets failing at a higher rate than younger assets. Where this relationship did not hold, such as with Cellon-treated poles, there was a clear explanation for the divergence. The following subsections provide an overall assessment of the analysis insights.

2.6.4.1 Groundline

The cedar pole failures, and the resulting POF curve, demonstrated a straight-forward relationship between pole age and inspection failures. The older the pole, the higher the failure rate.

The pine pole failure and POF curves were more complex than the corresponding cedar curves, to account for the increased incidence of Cellon-treated, pine poles in and around the 1970s.

2.6.4.2 Pole Top

The pole top failures, and the resulting POF curve, had three distinct sections based on the install date of the associated pole: pre-1950 install date, 1950-2009 install date and post-2009 install date.

The relatively lower pole top inspection failures for the pre-1950 poles seemed likely to stem from many of those oldest poles having previously received new pole tops, leaving many pole tops younger than their associated poles.

The relatively lower pole top inspection failures for the post-2009 poles seemed likely to stem from a change to pole top standard in recent years. New poles likely had better, stronger pole tops than their older counterparts.

2.7 Accessibility

The ability of work crews to access an asset has an impact on the duration of the outage and the cost to restore that part of the system. For example, rear-lot structures take much longer and cost more to restore than front-lot structures. To take differences in accessibility into account, 1898 & Co. performed a geospatial analysis of each structure against a data set of roads. Structures within a certain distance of the road were designated as having roadside access, while others were designated as in the deep right-of-way (ROW). These designations were considered when calculating restoration activity costs in the Integrated Resilience, Reliability, & Risk Investment Model. Based on this analysis, approximately 48% of DTE's poles have street access.

3.0 Major Events Impacting DTE's System

This section reviews the historical major weather-based resiliency events that have impacted DTE's electric service area and customers. The range of resiliency events that impacted the DTE's distribution system are from January 1, 1998, through September 30, 2025, as documented by NOAA. At the time this analysis was performed, the complete data for 2025 was not available from NOAA.

This information serves as the basis for understanding the expected frequency of similar resiliency events in the future. The results of the analysis performed by 1898 & Co. help correlate the NOAA event database with DTE's historical outage records which serve as the basis for understanding the customer impact of each resiliency event. Finally, this section concludes with a prioritization of weather events based on resilience risk.

3.1 NOAA Events

The database includes weather events (e.g., thunderstorms, ice storms) from 1998 through September 30, 2025. This database helped identify the resiliency events impacting the DTE service area and the expected frequency of different resiliency events.

The NOAA database records events at the county level. 1898 & Co. mined this data for all counties in DTE's service area. Table 3-1 lists the weather-based events contained in the database and provides definitions for each.

Table 3-1: Extreme Weather Resiliency Events[5]

No.	Resiliency Event Type	Resiliency Event	Definition
1	Storm	Thunderstorm Wind	Winds, arising from convection (occurring within 30 minutes of lightning being observed or detected), with speeds of at least 50 knots (58 mph), or winds of any speed (non-severe thunderstorm winds below 50 knots) producing a fatality, injury, or damage.
2		Lightning	A sudden electrical discharge from a thunderstorm, resulting in fatality, injury, and/or damage.
3		High Wind	Sustained non-convective winds of 35 knots (40 mph) or greater lasting for 1 hour or longer, or gusts of 50 knots (58 mph) or greater for any duration (or otherwise locally/regionally defined).
4		Hail	Hail is defined as frozen precipitation in the form of balls or irregular lumps of ice. Hail of any size may be reported, in hundredths of an inch, although the smallest measure in the hail conversion table is 0.25 inches. This report uses "Hail" to refer to hail that occurs not in connection with a winter-weather event and not during the months of December, January, and February.
5	Flooding	Flood	Any high flow, overflow, or inundation by water which causes damage.
6		Flash Flood	A life-threatening, rapid rise of water into a normally dry area beginning within minutes to multiple hours of the causative event (e.g., intense rainfall, dam failure, ice jam). Six inches or more of swiftly moving water flowing over a road or bridge posing a threat to life or property is one of many suggested guidelines for determining if an event was a Flash Flood.
7	Tornado	Tornado	A violently rotating column of air, extending to or from a cumuliform cloud or underneath a cumuliform cloud, to the ground, and often (but not always) visible as a condensation funnel.
8	Winter	Winter Storm	A winter weather event that has more than one significant hazard (i.e., heavy snow and blowing snow; snow and ice; snow and sleet; sleet and ice; or snow, sleet and ice) and meets or exceeds locally/regionally defined 12 and/or 24-hour warning criteria for at least one of the precipitation elements.
9		Heavy Snow	Snow accumulation meeting or exceeding locally/regionally defined 12 and/or 24-hour warning criteria. This could mean values such as 4, 6, or 8 inches or more in less than 12 hours or less; or 6, 8, or 10 inches in 24 hours or less.
10		Winter Weather	A winter precipitation event that causes a death, injury, or a significant impact to commerce or transportation, but does not meet locally/regionally defined warning criteria. A Winter Weather event could result from one or more winter precipitation types (snow, or blowing/drifting snow, or freezing rain/drizzle).
11		Ice Storm	Ice accretion meeting or exceeding locally/regionally defined warning criteria (typical value is 1/4 or 1/2 inch or more).
12		Blizzard	A winter storm which produces the following conditions for three (3) consecutive hours or longer: (1) sustained winds or frequent gusts 30 knots (35 mph) or greater, and (2) falling and/or blowing snow reducing visibility frequently to less than 1/4 mile

[5] Strassberg, G., & D. Murphy, J. (2021). *NATIONAL WEATHER SERVICE INSTRUCTION 10-1605*. https://www.nws.noaa.gov/directives/sym/pd01016005curr.pdf.

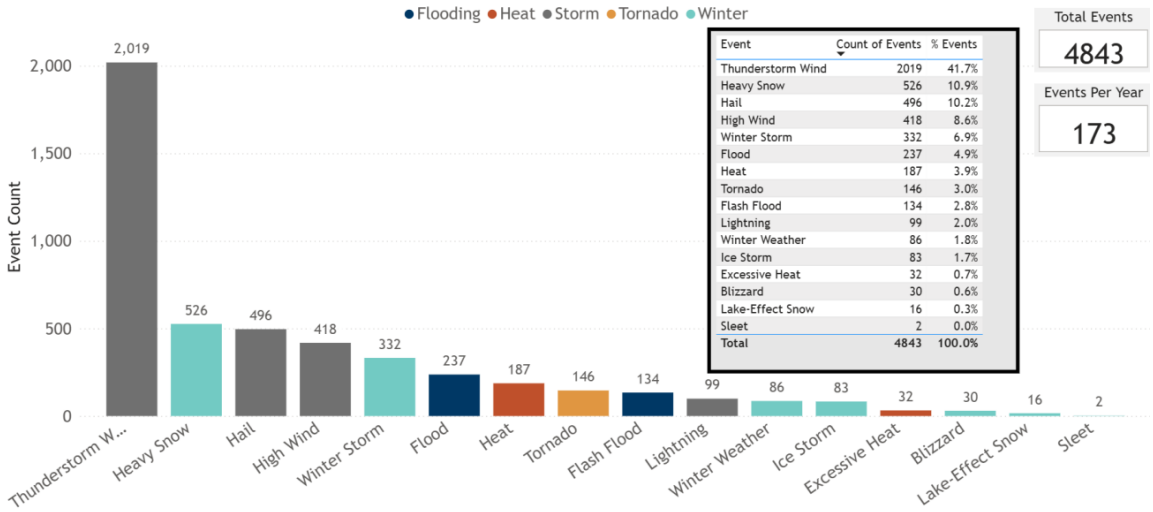
13		Lake Effect Snow	Convective snow bands that occur in the lee of large bodies of water (e.g., the Great Lakes or the Great Salt Lake), when relatively cold air flows over warm water. In extreme cases, snowfall rates of several inches per hour and thunder and lightning may occur. Lake-effect snow accumulations meet or exceed locally defined 12 and/or 24 hour warning criteria (typical values of 6 to 8 inches within 12 hours or 8 to 10 inches within 24 hours).
14		Sleet	Sleet accumulations meeting or exceeding locally/regionally defined warning criteria (typical value is 1/2 inch or more).
15	Heat	Excessive Heat	Excessive Heat results from a combination of high temperatures (well above normal) and high humidity. An Excessive Heat event occurs and is reported in Storm Data whenever heat index values exceed locally/regionally established excessive heat warning thresholds.
16		Heat	A period of heat resulting from the combination of high temperatures (above normal) and relative humidity. A Heat event occurs and is reported in Storm Data whenever heat index values meet or exceed locally/regionally established advisory thresholds.

For this analysis, 1898 & Co. excluded drought events from the analysis since their durations are extremely long making the outage correlation challenging with a reasonable degree of certainty. Additionally, wildfire is not covered in the 1898 & Co. report.

Figure 3-1 and Figure 3-2 show the summary results from the NOAA database of storms to impact the DTE service area from 1998 to September 30, 2025. At the time this analysis was performed using a partial year dataset for 2025 as the complete data was not available from NOAA. These figures include 5 different event categories that summarize 16 different event types as shown in Table 3-1. The chart shows a wide diversity of events impacting DTE's customers. From the NOAA records, 4,843 weather-based resiliency events have affected the DTE service area since 1998, averaging 173 events per year. The most common event category is the Storm category, with Thunderstorm Wind events accounting for 2,019 events equating to 42% of total events. It is important to note that lightning-related outages are primarily represented within the "Thunderstorm Wind" category due to the way NOAA classifies severe weather events. Because lightning typically occurs alongside convective storm activity that meets wind event criteria, it is grouped under this

broader classification rather than being reported separately. This information is the basis for estimating the future frequency of resiliency events that will impact DTE's service area and customers. Figure 3-2 shows the resiliency event count for DTE's service area broken down by year and event type beginning in 1998 for all 4,843 events.

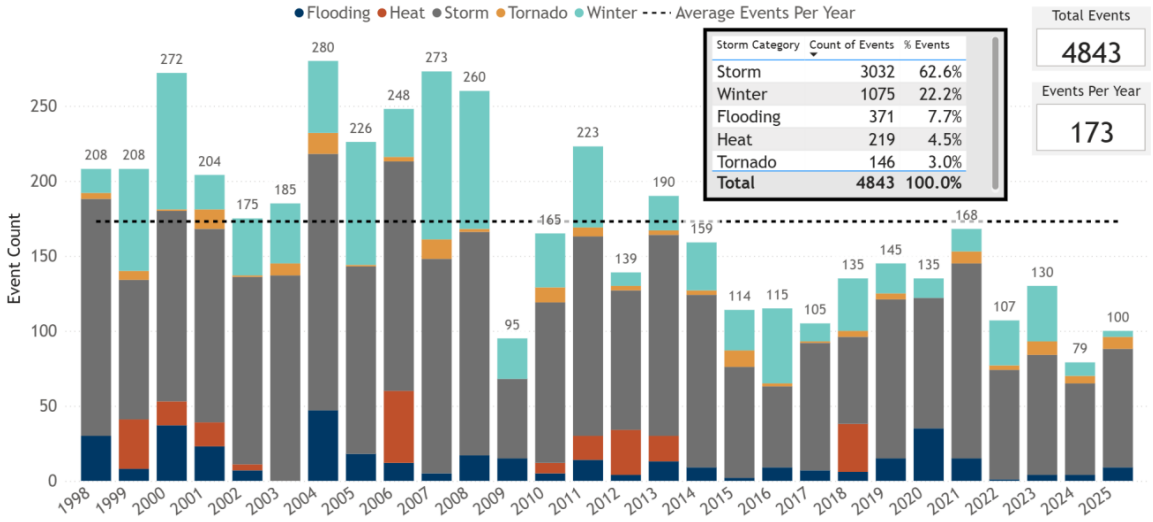
Figure 3-1: Extreme Weather Events in DTE's Service Area (1998- September 30, 2025)[6]



Event	Count of Events	% Events
Thunderstorm Wind	2019	41.7%
Heavy Snow	526	10.9%
Hail	496	10.2%
High Wind	418	8.6%
Winter Storm	332	6.9%
Flood	237	4.9%
Heat	187	3.9%
Tornado	146	3.0%
Flash Flood	134	2.8%
Lightning	99	2.0%
Winter Weather	86	1.8%
Ice Storm	83	1.7%
Excessive Heat	32	0.7%
Blizzard	30	0.6%
Lake-Effect Snow	16	0.3%
Sleet	2	0.0%
Total	4843	100.0%

[6] Ncei. (n.d.). *Storm Events Database | National Centers for Environmental Information*. https://www.ncdc.noaa.gov/stormevents/ with analysis by 1898 & Co.

Figure 3-2: Count of Weather-Based Resiliency Events for DTE's System by Year[7]

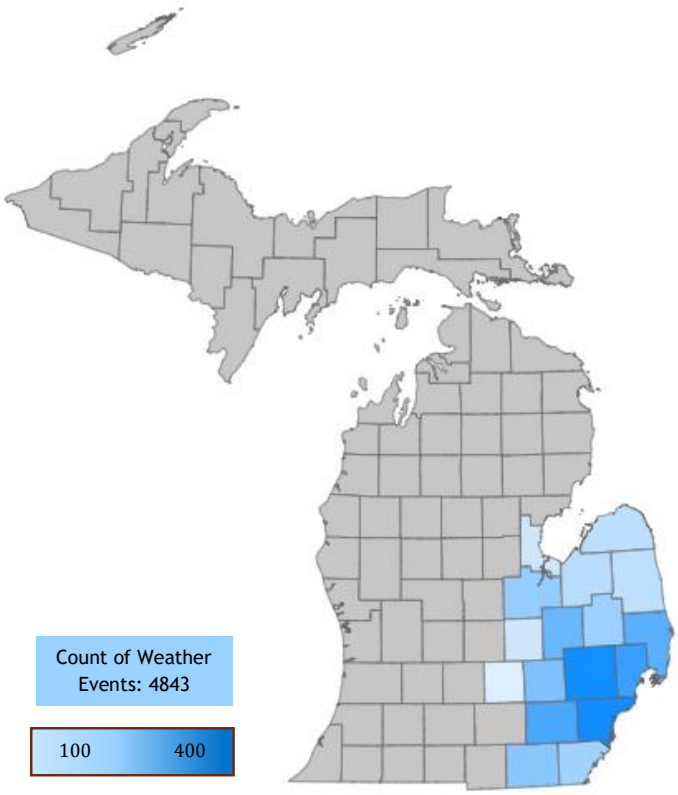


This figure shows a wide range of events occurring over the years. Storm events account for the highest percentage of events to impact the DTE service area at 62.6%.

1898 & Co. utilized NOAA data to organize historical events by county across DTE's service area. Figure 3-3 provides an overview of the counties that intersect DTE's service area with the color gradient showing counties with more events in dark blue and counties with less events in light blue. It is at this level that 1898 & Co. captured each resiliency event.

[7] *Id.* with analysis by 1898 & Co.

Figure 3-3: DTE Service Area Counties with NOAA Recorded Storms



3.2 NOAA Events and Outage Records

The previous section provided foundational information to understand the range of resiliency-event types that impact the DTE service area, where those resiliency events tend to occur within the DTE service area, and the number of resiliency events. This information provides insights into resiliency-event frequency. This section includes an assessment of the impact of these events. 1898 & Co. conducted a correlation analysis between the NOAA event data and DTE's historical outage records to perform that assessment.

As noted above, this evaluation excludes wildfire and drought events. From 2007 through September 30, 2025, 1898 & Co. correlated events in NOAA to DTE's outage records based on time stamps from both data sets. 1898 & Co. selected 2007 as the earliest year to utilize from DTE's historical outage records, and September 30, 2025,

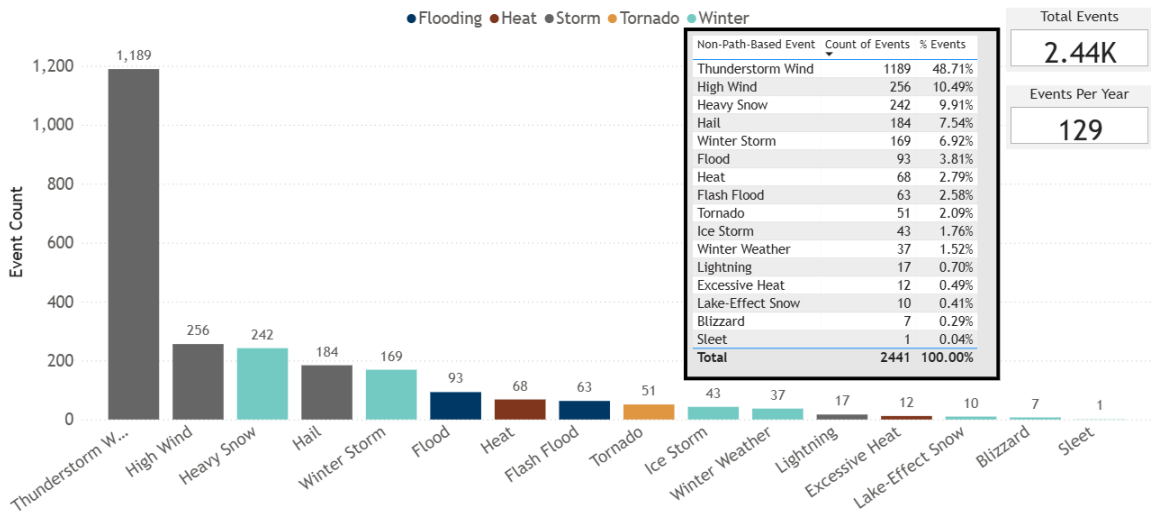
as the latest year for which complete NOAA event data is available at the time of the study. This correlation allows customer outages to be directly linked to specific resiliency events to assess how the system performed during an individual event. To capture weather events not included in the NOAA database, 1898 & Co. analyzed DTE's outage records. 1898 & Co. identified days with more than thirty outages caused by "Weather" or "Lightning." By classifying these days as distinct weather events, 1898 & Co. added 364 events to the analysis, to more accurately supplement the existing NOAA data based on DTE's observed outage data.

3.2.1 Weather Events from 2007 to September 30, 2025

1898 & Co. identified over 2,441 weather events, as defined by NOAA, where an outage was recorded in DTE's OMS. Figure 3-4 shows the type of events that 1898 & Co. mapped to DTE's OMS records over this period from 2007 to September 30, 2025. Figure 3-5 shows the same information summarized by major weather category and by year.

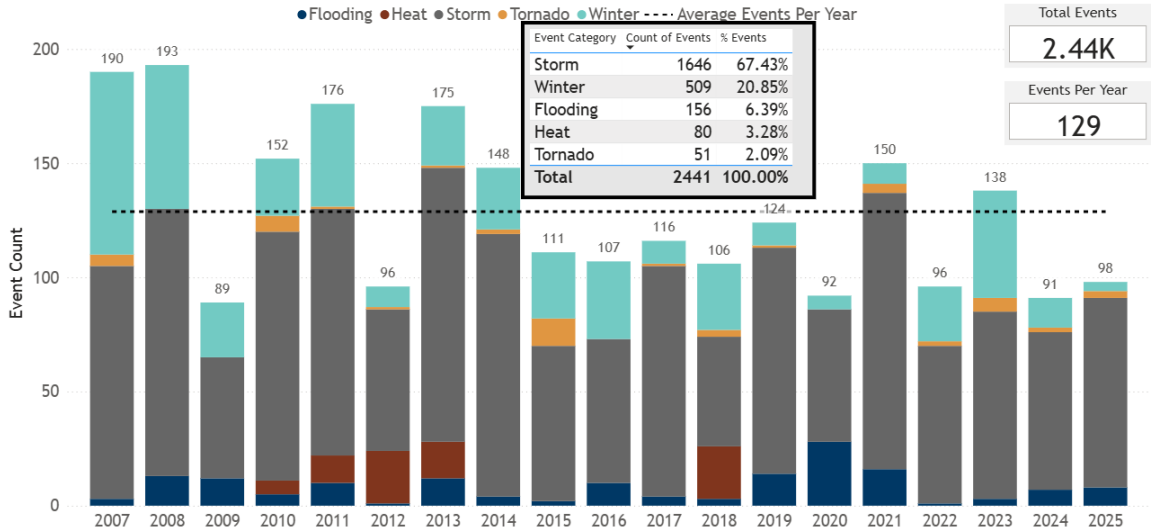
Major Events Impacting DTE's System

Figure 3-4: Weather Events Identified in DTE's Outage Records (2007-September 30, 2025)[8]



Non-Path-Based Event	Count of Events	% Events
Thunderstorm Wind	1189	48.71%
High Wind	256	10.49%
Heavy Snow	242	9.91%
Hail	184	7.54%
Winter Storm	169	6.92%
Flood	93	3.81%
Heat	68	2.79%
Flash Flood	63	2.58%
Tornado	51	2.09%
Ice Storm	43	1.76%
Winter Weather	37	1.52%
Lightning	17	0.70%
Excessive Heat	12	0.49%
Lake-Effect Snow	10	0.41%
Blizzard	7	0.29%
Sleet	1	0.04%
Total	**2441**	**100.00%**

Figure 3-5: Weather Summary Events by Year Identified in DTE's Outage Records (2007-September 30, 2025)[9]



Event Category	Count of Events	% Events
Storm	1646	67.43%
Winter	509	20.85%
Flooding	156	6.39%
Heat	80	3.28%
Tornado	51	2.09%
Total	2441	100.00%

[8] *Id.* with analysis by 1898 & Co.
[9] *Id.* with analysis by 1898 & Co.

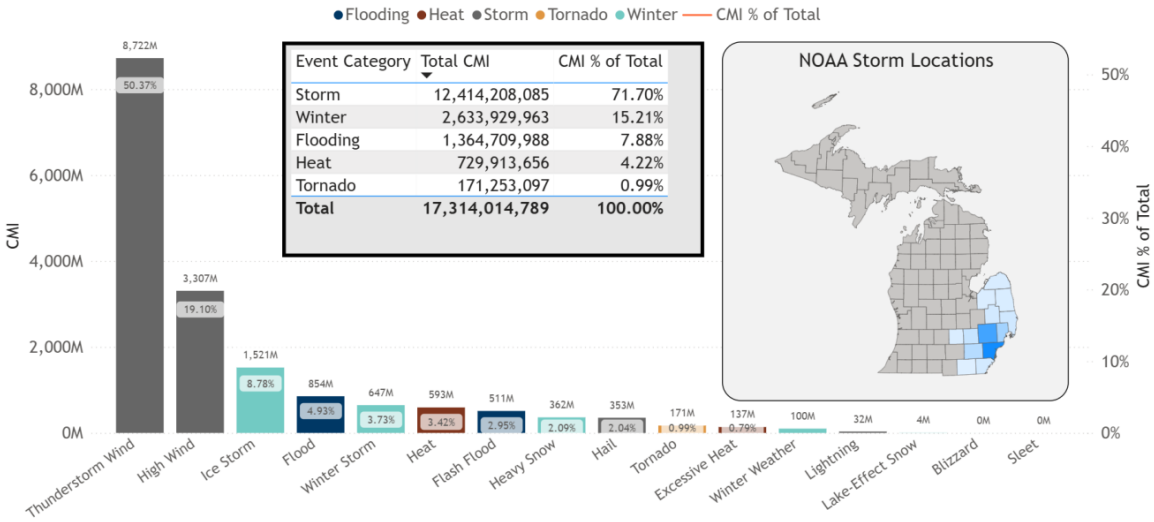
3.2.2 Weather Events and Customer Minutes Interrupted

Between 2007 and September 30, 2025, DTE recorded approximately 21.8 billion Customer Minutes Interrupted (CMI) from outages. An analysis by 1898 & Co. found that a large majority of these interruptions happened during inclement weather.

The analysis linked 16.3 billion CMI, about 74% of the total, to 2,077 severe weather events documented in the NOAA Storm Database. An additional 918 million CMI, or 5.3%, were also attributed to weather as identified by 1898 & Co. when analyzing the DTE outage records. These were identified by finding days with more than thirty outages coded as "Weather" or "Lightning" in DTE's OMS system, which added 364 weather events not recorded by NOAA. This brings the total of weather events identified to 2,441 as shown in Figure 3-4.

Combining these findings, a total of 17.3 billion CMI, or 79.3% of all outages, occurred during inclement weather events. The remaining 4.5 billion CMI (20.7%) happened during "blue-sky" days. Figure 3-6 shows the mapped CMI for each event type.

Figure 3-6: Mapped CMI to OMS and Weather Events (2007 to September 30, 2025)



Event Category	Total CMI	CMI % of Total
Storm	12,414,208,085	71.70%
Winter	2,633,929,963	15.21%
Flooding	1,364,709,988	7.88%
Heat	729,913,656	4.22%
Tornado	171,253,097	0.99%
Total	**17,314,014,789**	**100.00%**

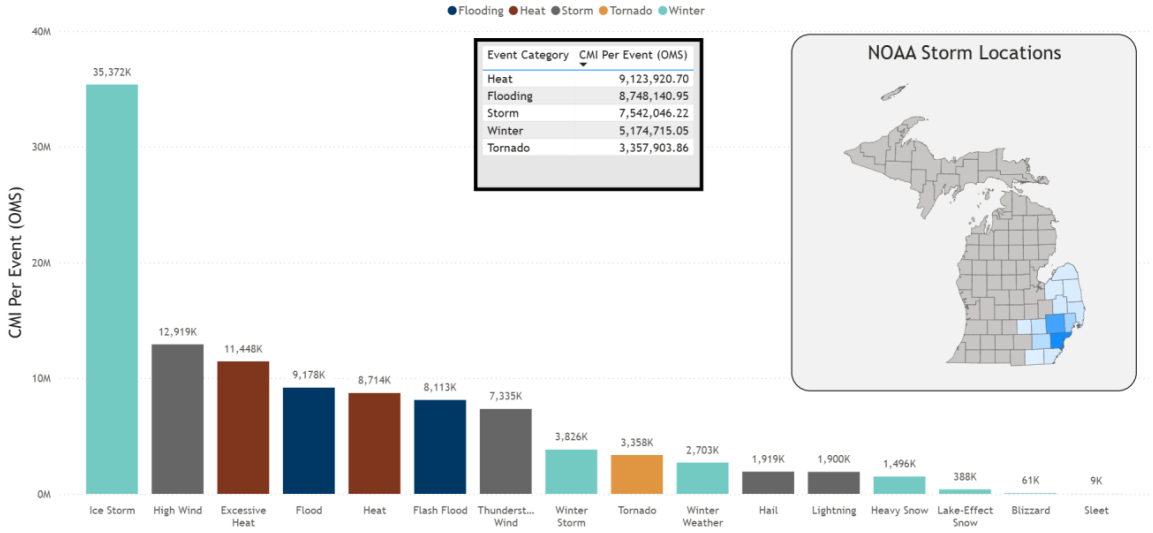
This data illustrates the significant contributions of major weather events to customer outages and the need for resilience investment to mitigate these impacts. The figures above show the following:

1) Two event types below account for nearly 70% of the mapped CMI:
   - Thunderstorm Wind events are the most impactful, with 50.37% of the mapped CMI.
   - High Wind events account for another 19.10%.
2) Seven of the remaining fourteen event types collectively account for an additional 27.94% of the mapped CMI. These seven event types are Ice Storm (8.78%), Flood (4.93%), Winter Storm (3.73%), Heat (3.42%), Flash Flood (2.95%), Heavy Snow (2.09%) and Hail (2.04%).
3) The remaining seven event types account for less than 1% each of all mapped CMI. These are Tornado, Excessive Heat, Winter Weather, Lightning, Lake-Effect Snow, Blizzard and Sleet. Collectively, these account for less than 3% of all CMI.

3.2.3 Customer Minutes Interrupted Per Event

Figure 3-7 shows the historical average CMI per event for each event type. These results are derived by taking the CMI from Figure 3-6 and dividing by the number of events from Figure 3-4. These values serve as the basis to understand the consequence of individual events on the system.

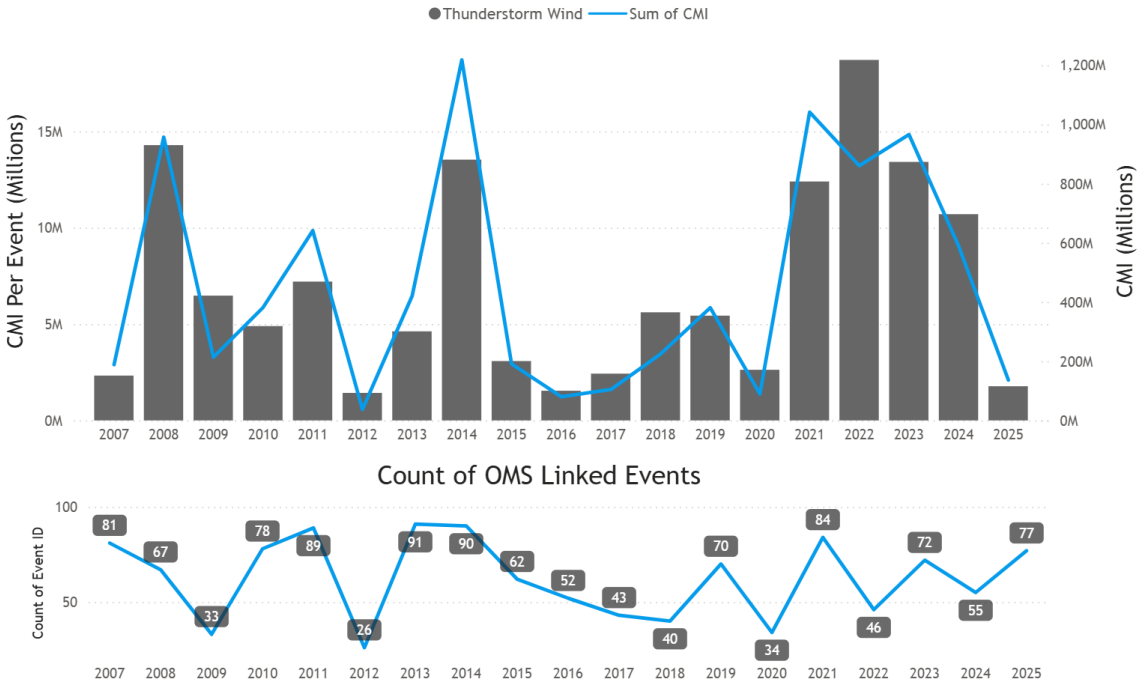
Figure 3-7: CMI Per Event



Event Category	CMI Per Event (OMS)
Heat	9,123,920.70
Flooding	8,748,140.95
Storm	7,542,046.22
Winter	5,174,715.05
Tornado	3,357,903.86

While Figure 3-7 shows the average CMI per Event over the 2007 through 2025 (through September) time period, Figure 3-8, Figure 3-9, and Figure 3-10 provide a more detailed summary of the CMI per event by year for Thunderstorm Wind, High Wind, and Ice Storm categories, the three highest ranking event types by CMI. These figures demonstrate the significant uncertainty in event impacts. For the top portion of the graph showing the bar chart and line, the blue line represents the total CMI attributed to the storm category for a specific year aligning to the right side of the Y-axis. The bars show the total average CMI per event by year aligned with the left side of the Y-axis. The bottom portion of the graph shows the total count of events linked to the DTE OMS for each year. The figures below show that event impacts, from a CMI perspective, have a wide distribution from year to year.

Figure 3-8: Sum of CMI, Annual CMI Per Event, and Count of OMS Events - Thunderstorm Wind



Major Events Impacting DTE's System

Figure 3-9: Sum of CMI, Annual CMI Per Event, and Count of OMS Events - High Wind

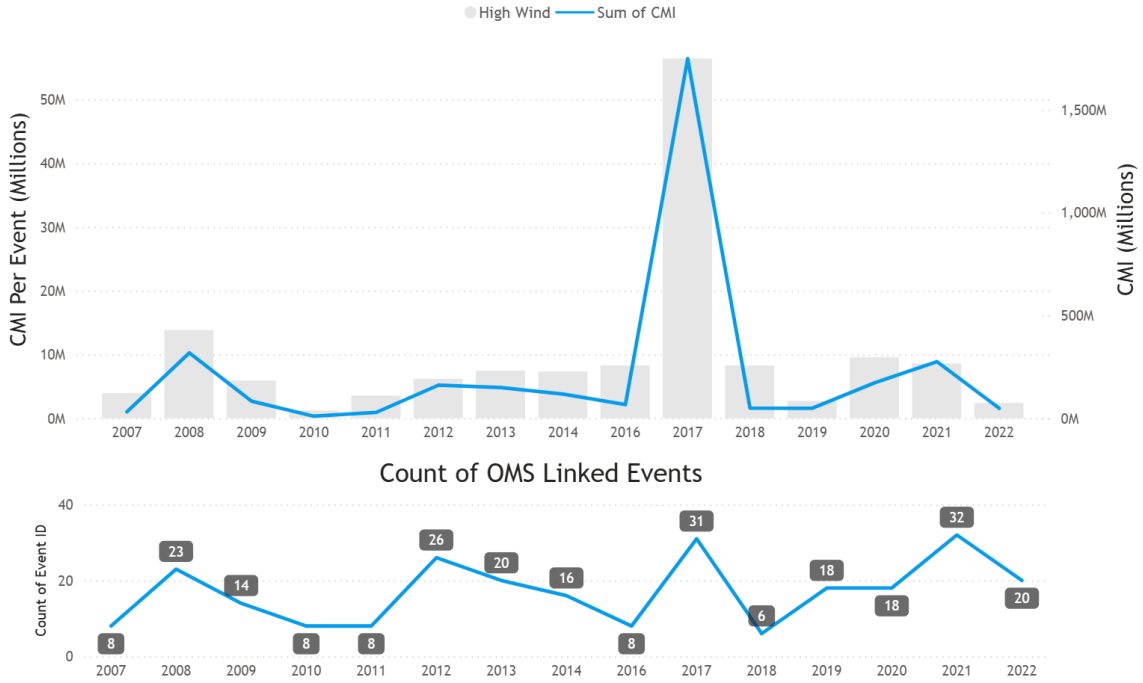
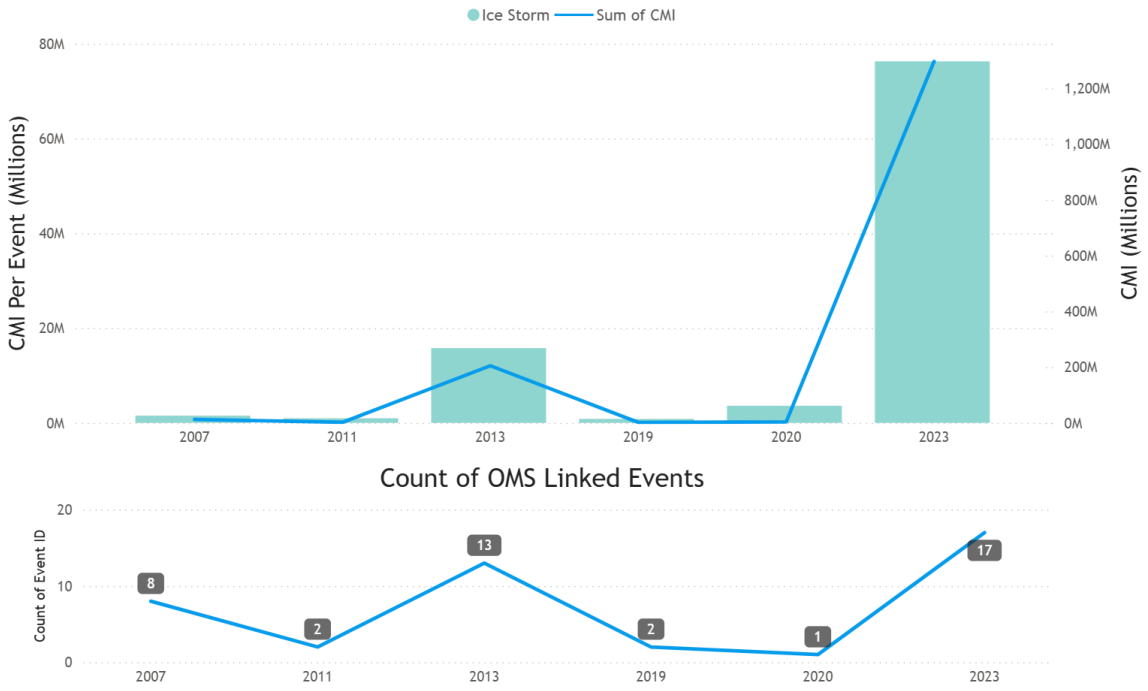


Figure 3-10: Sum of CMI, Annual CMI Per Event, and Count of OMS Events - Ice Storm



3.3 Event Impact Summary

Table 3-2 provides a summary of the resiliency events evaluated by 1898 & Co. that impacted DTE customers. The table includes the events discussed in Section 3.2. Table 3-2 ranks the quantified event types based on their Average Events Per Year (Event Frequency) and the CMI Per Event (Event Impact). The Average Annual CMI is calculated by taking the average number of events per year and multiplying it by the CMI per event. The average number of events per year is from 2007 to September 30, 2025, based on the weather data.

The table shows that Thunderstorm Wind is the main resiliency event impacting customers. Its estimated annual average CMI of approximately 460 million is substantially higher than that of the second-ranked event, High Wind, which has an

annual average CMI of approximately 174 million. Thunderstorm Wind ranks first in event frequency and in CMI per event (event impact).

Ice Storm events occur infrequently, with an average of 2.3 per year, but their severe consequences result in the event impact ranking of 1. Conversely, Thunderstorm Wind events happen far more often, with an average of 63 per year. This high frequency is what drives their top position for the Event Impact rank despite having a lower CMI for each individual event.

Overall, the results show that while Ice Storm has the most significant single-event impact and Thunderstorm Wind occurs most frequently, it is Thunderstorm Wind that has the most significant overall effect on customers. Its combination of the largest

annual average CMI and the highest number of yearly events clearly demonstrates its outsized influence on system resiliency.

The information in Table 3-2 is the core event data utilized within the Integrated Resilience, Reliability, & Risk Investment Model to estimate the quantified benefits of resilience investments across the system. This is discussed in the next section.

Table 3-2: Prioritization of Resiliency Events

Event Category	Event Type	Average Events Per Year (OMS)	CMI Per Event (OMS)	Annual Average CMI (OMS)	Event Frequency	Event Impact Rank
Storm	Thunderstorm Wind	62.58	7,335,309	459,035,897	1	7
Storm	High Wind	13.47	12,918,684	174,062,271	2	2
Winter	Heavy Snow	12.74	1,495,666	19,050,062	3	13
Storm	Hail	9.68	1,918,667	18,580,774	4	11
Winter	Winter Storm	8.89	3,826,181	34,032,869	5	8
Flooding	Flood	4.89	9,178,460	44,926,145	6	4
Heat	Heat	3.58	8,713,799	31,186,227	7	5
Flooding	Flash Flood	3.32	8,112,908	26,900,696	8	6
Tornado	Tornado	2.68	3,357,904	9,013,321	9	9
Winter	Ice Storm	2.26	35,372,384	80,053,290	10	1
Winter	Winter Weather	1.95	2,703,375	5,264,468	11	10
Storm	Lightning	0.89	1,900,481	1,700,431	12	12
Heat	Excessive Heat	0.63	11,447,945	7,230,281	13	3
Winter	Lake-Effect Snow	0.53	388,333	204,386	14	14
Winter	Blizzard	0.37	60,601	22,327	15	15
Winter	Sleet	0.05	9,348	492	16	16

4.0 Benefits Modeling Approach

1898 & Co. utilized a resilience, reliability, and risk-based planning approach to identify, prioritize, and perform a Benefit-Cost Analysis to support the investment justification for the investment programs outlined above. The planning approach utilizes a suite of planning models and the Integrated Resilience, Reliability, & Risk Investment Model developed by 1898 & Co. For the purposes of this evaluation, resilience, reliability, and risk benefits for investment activities are estimated from a customer-centric perspective. The customer benefits are shown in terms of the:

1. Decrease in utility restoration costs; and
2. Decrease in the number of customers impacted and the duration of the overall outage, calculated as CMI and monetizing the CMI.

From these benefit streams, the model calculates the resilience, reliability, and risk BCR for each investment activity, circuit, substation (where appropriate) and program.

$$Resilience, Reliability, \& \ Risk \ BCR = \frac{Lifecycle \ PV \ Avoided \ Costs + Lifecyle \ PV \ Avoided \ \$CMI}{Lifecyle \ Investment}$$

The Resilience, Reliability, & Risk BCR, as used in this analysis, is a single value that represents complex modeling of resiliency and reliability failure modes (including Major Event Day type outages), infrastructure vulnerability, infrastructure rebuild costs, and other financial factors to provide a robust and reliable measure to evaluate individual investments from a quantified customer benefit perspective.

This single value, Resilience, Reliability, & Risk BCR, for each circuit, substation, and program level constitutes a sophisticated multi-factored analysis. The results of this evaluation are measured at the circuit and/or substation level to align with DTE's execution approach. The Resilience, Reliability, & Risk BCR incorporates the following factors for each investment activity for each program:

Resiliency & Reliability Failure Modes & Events

- Range of resiliency events.

- Frequency of those resiliency events.
- Location of events by county.
- The expected asset-level probability of failure (POF) is based on expected equipment lives and types of failures.
- Expected Impact to customers, customer minutes interrupted (CMI), is based on historical customer impacts.
- The decrease in customer outage impacts for DA is directly estimated from historical outage records.

Infrastructure Vulnerability

- Number of assets within each investment activity.
- Age of the assets within each investment activity and their expected lives.
- Known equipment original design vulnerabilities (*e.g.*, Cellon-treated poles)
- Vegetation density around each span of conductor.
- Number of downstream customers impacted for each investment activity.
- Types of customers (residential, commercial & industrial (C&I) based on usage into 20 different groups) for each investment activity.
- The accessibility of the infrastructure in terms of street access.

Infrastructure Rebuild Costs

- The investment needed to mitigate the resilience, reliability, and risk events, including:
  - Type of assets.
  - Number of assets.
  - Location of the assets (rear lot/front lot).

Financial Factors

- Discounted cash flow methodology over the life-cycle of the infrastructure, shown in Table 4-1: Economic Assumptions
- The Interruption Cost Estimator (ICE) calculator (see Section 4.2) to evaluate the cost of an outage for the range of customer types and outage durations.

1898 & Co. has carefully integrated all these factors within each model to estimate benefits objectively, consistently, and precisely for each investment activity. **This approach makes the Benefit-Cost ratio (BCR) value a robust and reliable measure to help understand the justification for investment activities.** This multi-factored and quantified metric provides confidence that investments will provide benefits in excess of costs for customers. Therefore, the BCR value is an appropriate metric to guide investment selection and prioritization on the DTE system.

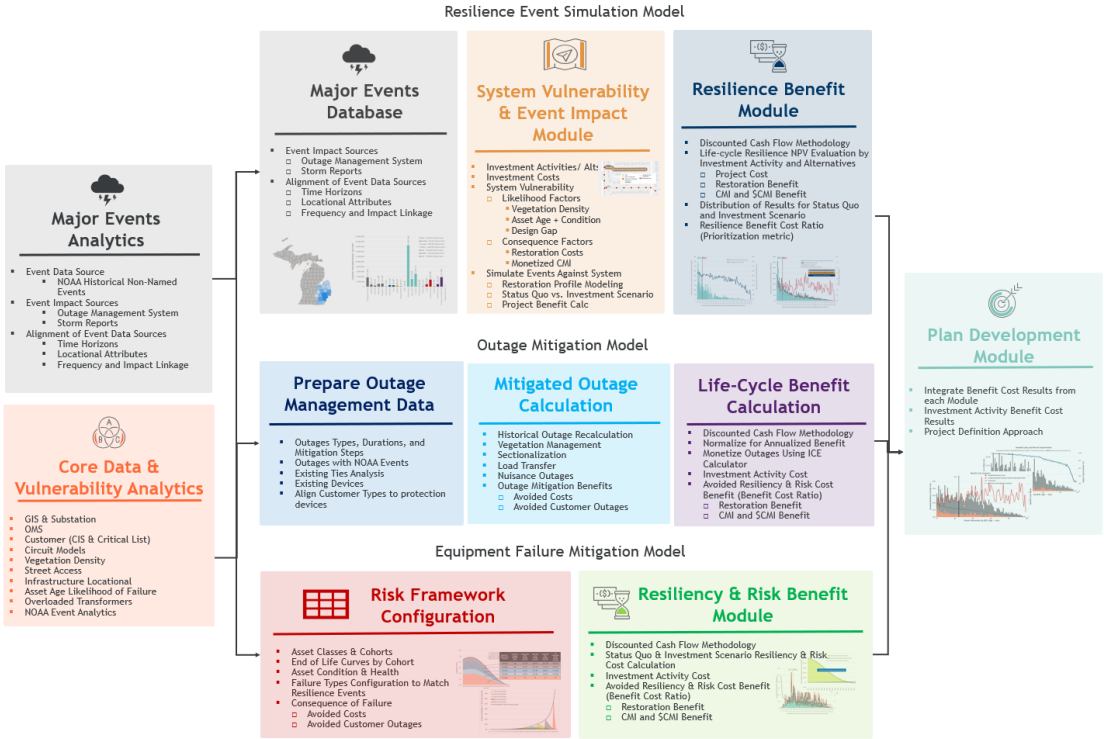
While the Resilience, Reliability, & Risk BCR incorporates many factors, it does not capture all benefit streams. The list above shows that the BCR incorporates most of the objective factors within the quantified benefits assessment. 1898 & Co. recognizes that more difficult-to-quantify risk factors have not been incorporated into the evaluation. Key factors are safety, areas of lower performance (e.g. Customers Experiencing Multiple Interruptions or CEMI), and cyber-security risks, including the risk that new regulations require additional cyber-security investment.

The Resilience, Reliability, & Risk BCR should be utilized as an important tool in prioritizing and selecting investments in concert with other criteria that incorporate benefits streams not included within the quantified evaluation as described above. Incorporating quantitative and qualitative assessments together is a powerful decision-making tool for utility investments.

The Integrated Resilience, Reliability, & Risk Investment Model employs a data-driven decision-making methodology using sophisticated algorithms to calculate the resilience, reliability, and risk benefits for each potential investment activity that makes up each program. Figure 4-1 provides an overview of the Integrated Resilience, Reliability, & Risk Investment Model utilized within the DTE Benefit-Cost Analysis.

Benefits Modeling Approach

Figure 4-1: Integrated Resilience, Reliability, & Risk Investment Model



The model first includes foundational data. These inputs include core data and vulnerability analytics, such as DTE's asset registers, equipment characteristics, GIS and substation data, outage history, distribution circuit models, and other asset-level information used to assess the specific vulnerabilities of DTE's system. Additional detail on these inputs is provided in Section 2.0.

The model also incorporates major storm event data, including historical storm and event information used to characterize major event risks and simulate future weather events. Additional information on the major events data is provided in Section 3.0.

The model includes three analytics models (Resilience Event Simulation Model, Outage Mitigation Model, and Equipment Failure Mitigation Model). Each of these analytics models estimates the expected avoided costs and avoided customer outages. Each analytics model was designed to estimate the resilience, reliability, and risk benefits of different investments based on the available data, asset types, benefit streams, and

failure types. The sub-sections below provide additional detail on each of the analytics models that estimate benefits.

4.1 General Assumptions

As noted above, the Resilience, Reliability, and Risk Investment Model uses a discounted cash flow methodology for the Benefit-Cost Analysis. Table 4-1 provides an overview of the assumptions used within the Benefit-Cost Analysis.

Table 4-1: Economic Assumptions

Assumption Description	Units	Value
Analysis Period: PTMM	Years	50
Analysis Period: Small Wire Replacement Program	Years	50
Analysis Period: URD Replacement Program	Years	50
Analysis Period: Cable Replacement Program	Years	50
Analysis Period: Breaker Replacement Program	Years	50
Analysis Period: Subtransmission SCADA	Years	40
Analysis Period: Distribution Automation	Years	20
Analysis Period: Communication Network	Years	40
Analysis Period: Subtransmission Redesign and Rebuild	Years	50
Analysis Period: 4.8 kV & 8.3 kV Conversion	Years	50
Escalation Rate	%	2.5%
Discount Rate	%	6.5%
Carrier Fees Escalation Rate	%	2.5%

4.2 ICE Calculator

One of the key assumptions for the Benefit-Cost Analysis (BCA) is the value for the cost of an outage. To monetize the cost of an outage, 1898 & Co. utilizes the Interruption Cost Estimator (ICE) Calculator 2.0, Phase 1 results. While phase 2 was released before the filing of this application, the release timing of late February 2026 was too late to incorporate into the Benefit-Cost Analysis. As such, this analysis is based on the phase 1 release, ICE 2.0. This report does include a review of the key differences between ICE 1.0, 2.0, and 2.2 for the DTE system further below.

The ICE Calculator is an electric reliability planning tool that was originally developed by Freeman, Sullivan & Co. and Lawrence Berkeley National Laboratory (Berkeley Labs). This tool is designed for electric reliability planners at utilities, government organizations, and other entities that are interested in estimating interruption costs and/or the benefits associated with reliability improvements in the United States.

The original version of the ICE calculator, referred to as ICE 1.0, was developed from 15 customer-interruption surveys conducted by 10 electric utilities from 1989 to 2012. The value of interruption costs in the calculator was based on customer surveys, yielding 34 data sets totaling over 105,000 observations from 1989 to 2012. The dataset included over 44,000 medium- to large-C&I customers, 27,000 small C&I customers, and 34,000 residential customers. The surveys collected were evaluated by two approaches:

4) **Willingness-to-pay (WTP) surveys for residential customers:** Residential respondents were asked how much they would be willing to pay to avoid a hypothetical power interruption. This approach captures both direct financial losses and intangible impacts such as inconvenience or discomfort.
5) **Direct cost measurement for commercial and industrial customers:** Businesses were asked to estimate the monetary losses they would experience during an outage. These costs could include lost production, lost sales, equipment restart costs, spoiled materials, and additional labor required to recover from the interruption.

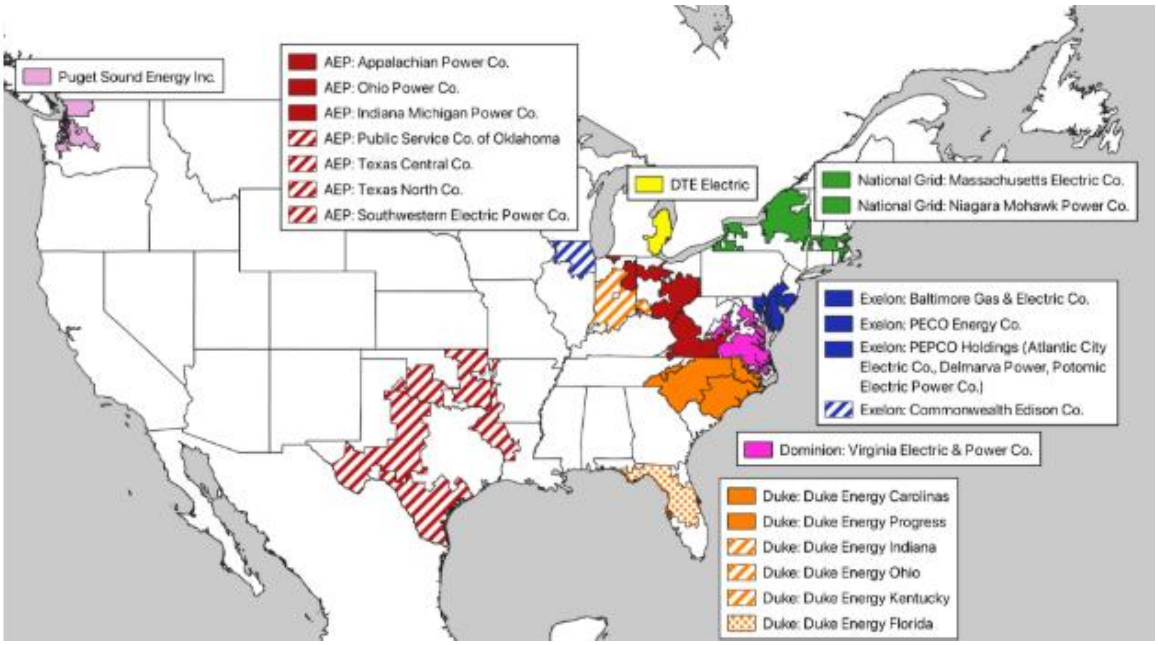
From the surveys, a statistical model for Customer Damage Functions (CDF) to estimate the cost of an outage was created for three different customer classes:

6) Residential customers
7) Small non-residential customers
8) Medium and large non-residential customers

Over time, the developers of the ICE calculator noted significant advancements in the societal use of electronic devices, in-home life-saving medical devices, and other technologies, including a higher number of people working from home. With most

surveys completed before these advancements, Lawrence Berkeley National Labs and Resource Innovations launched the "ICE 2.0 Initiative". The initiative was planned as a national survey comprised of multiple utilities to refresh the underlying survey data in ICE 1.0. To achieve the goal of updating surveys, Berkeley Labs contracted with electric utility sponsors to conduct updated interruption cost surveys that are statistically representative of each utility's customers. These updates are being performed in phases and Figure 4-2, created by Berkeley Labs, shows the electric utilities involved in the phase 1 update of ICE 2.0.

Figure 4-2: ICE 2.0 Phase 1 Utilities[10]



In addition to the support of the sponsoring utilities, Berkeley Labs also received input from the following organizations:

1. U.S. Department of Energy (U.S. DOE)
2. National Association of Regulatory Utility Commissioners (NARUC)
3. National Association of State Utility Consumer Advocates (NASUCA)
4. Energy Offices (NASEO)
5. Edison Electric Institute (EEI)

[10] (Lawrence Berkeley National Laboratory and Resource Innovations, 2025)

6. American Public Power Association (APPA)
7. National Rural Electric Cooperative Association (NRECA)
8. Electric Power Research Institute (EPRI)

4.2.1 ICE 1.0 Compared to 2.0

ICE 2.0 was developed to modernize the interruption cost estimation framework, improve data quality and consistency, and produce more reliable outage cost estimates for utility planning and regulatory analysis. Table 4-2 below highlights the difference between ICE 1.0 and 2.0:

Table 4-2: Summary of Differences between ICE 2.0 and 1.0[11]

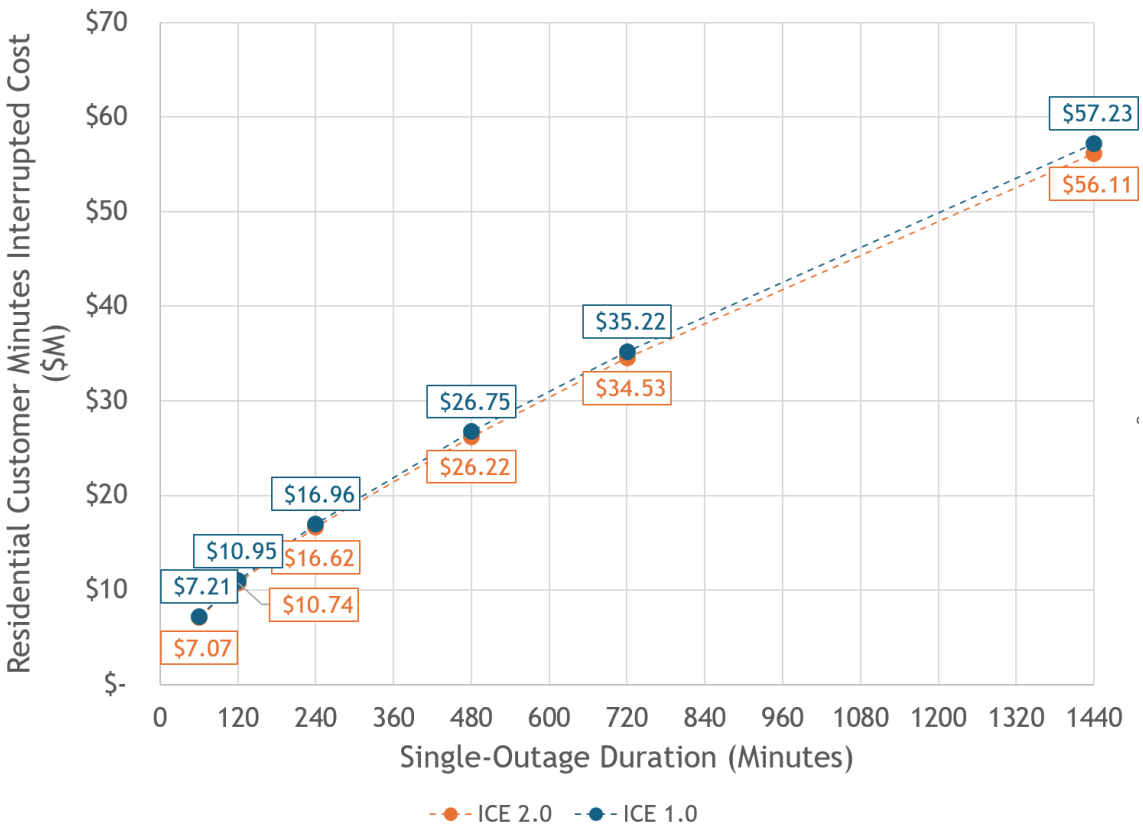
Category	ICE Calculator 1.0	ICE Calculator 2.0
Initial Release	Developed in 2009	Updated and released in 2025
Developers	Lawrence Berkeley National Laboratory and Freeman, Sullivan & Co.	Lawrence Berkeley National Laboratory and Resource Innovations
Purpose	Estimate economic costs of power interruptions for different customer classes	Updated national tool to provide more accurate and representative estimates of outage costs
Survey Years Used	Surveys conducted 1989–2012	Surveys conducted 2022–2024
Number of Survey Efforts	15 independent surveys	11 coordinated surveys (Phase 1)
Utility Coverage	10 utility service territories	24 utility service territories in Phase 1
Geographic Coverage	Primarily Western and Southeastern U.S.	Eastern and Midwestern U.S. and Pacific Northwest, with additional phases expanding coverage
Survey Administration	Surveys conducted independently by utilities with different methodologies	Surveys conducted in a coordinated national effort with identical survey instruments
Survey Questions	Varied questions across surveys	Standardized and consistent questions across all surveys
Interruption Durations Considered	Varied by survey, generally limited to 12 hours or less	Standardized durations: momentary, 2 hours, 8 hours, and 24 hours
Residential Valuation Method	Willingness-to-pay approach	Updated one-and-one-half-bound dichotomous choice (OHDC) willingness-to-pay method
Non-Residential Valuation Method	Direct cost estimation by businesses	Updated direct cost estimation with improved modeling
Customer Damage Functions (CDFs)	**Three models:** residential, small non-residential, medium/large non-residential	**Two models:** residential and non-residential
Model Structure	Two-part econometric models for each customer class	Improved econometric models including generalized linear model (GLM) and probit approaches
Additional Variables Considered	Limited variables such as duration, usage, income, and industry	Expanded variables including backup generation, work-from-home prevalence, industry type, and advance warning
Data Consistency	Data collected with different survey designs and sampling methods	Consistent sampling and survey methodology across utilities
Objective of Update	Provide first national estimate of outage costs	Provide more modern, statistically robust, and nationally representative estimates of outage costs

To understand the impacts of switching from ICE 1.0 in the 2025 BCA to ICE 2.0 in the 2026 BCA, 1898 & Co. compared CDF values for different outage durations. Figure 4-3 shows the difference between ICE 1.0 and 2.0 for the outage value for DTE residential customers for different duration outages. The blue line shows ICE 1.0 values, and the orange line shows ICE 2.0 values. For residential customers, power outages are valued

[11] (Lawrence Berkeley National Laboratory and Resource Innovations, 2025)

slightly lower with ICE 2.0 than with ICE 1.0, making the difference between the curves largely negligible.

Figure 4-3: Comparison of ICE 1.0 and 2.0 for the Value of an Outage for DTE Residential Customers



To understand the potential impact on the value of lost load and the associated benefits of different-duration interruptions for non-residential (C&I) customers between ICE 1.0 and 2.0, 1898 & Co. used DTE's C&I metered customer base and historical annual kWh usage to compare the cost of an outage over a 24-hour period. Figure 4-4 and Table 4-3 compare the difference in the cost of interruption between ICE 1.0 and 2.0, assuming all non-residential customers experience an outage of the designated duration. This approach was utilized since the cost of an interruption is based on kWh usage.

Figure 4-4: Comparison of ICE 1.0 and 2.0 for the Value of an Outage for DTE Non-Residential Customers

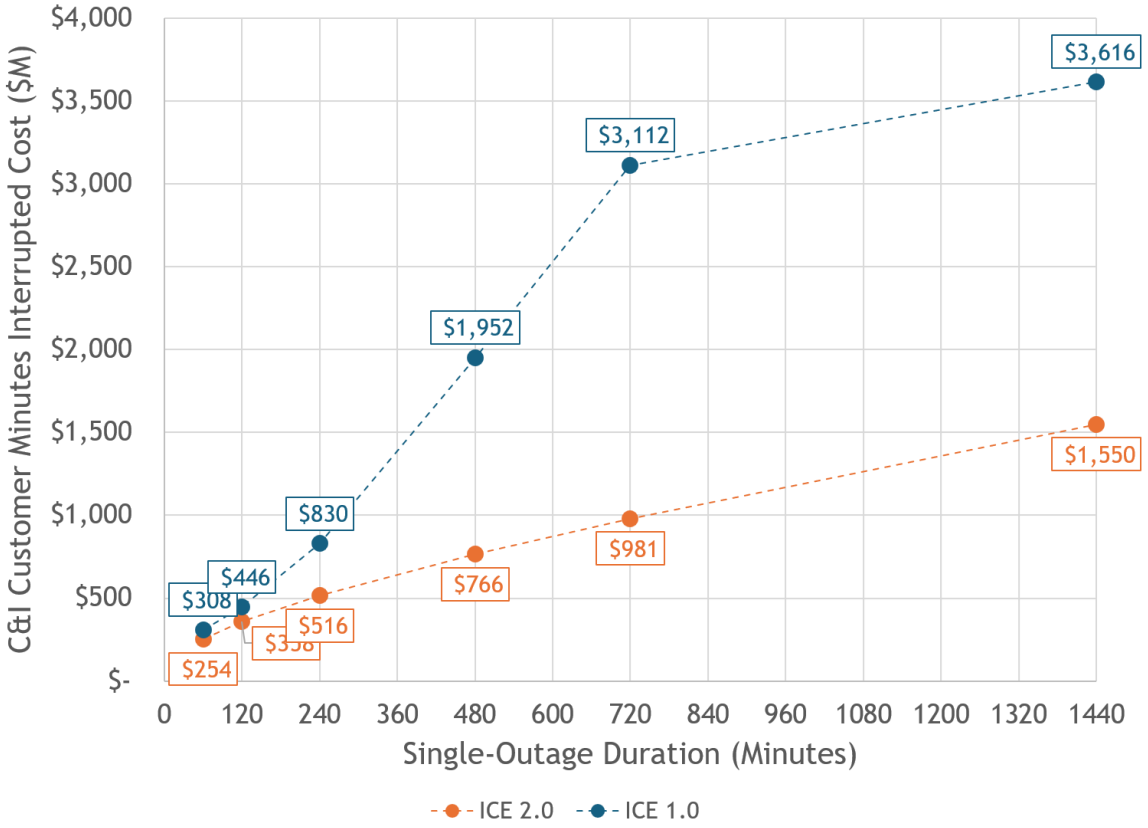


Table 4-3: Difference in cost of interruption between ICE 1.0 and 2.0 for DTE non-residential customers

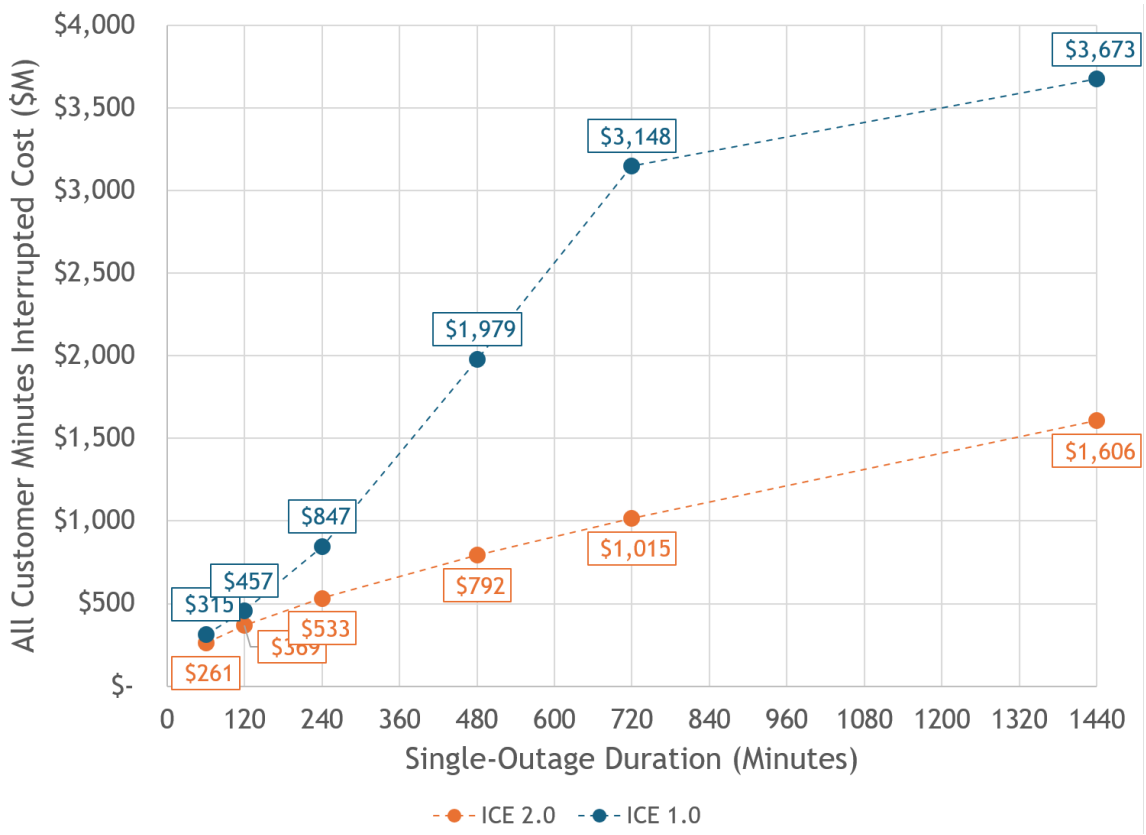
Outage Duration (Minutes)	Estimated Customer Cost ($M)		
	ICE 2.0	ICE 1.0	Delta Between 2.0 and 1.0
60	$253.99	$308.01	-18%
120	$358.25	$446.18	-20%
240	$516.14	$829.71	-38%
480	$765.77	$1,952.37	-61%
720	$980.91	$3,112.33	-68%
1440	$1,549.79	$3,616.09	-57%

In general, 1898 & Co. identified less monetized CMI benefits related to the cost of interruption by shifting from ICE 1.0 to 2.0. Berkeley Labs notes that interruption costs for non-residential customers are comparable for shorter-duration outages, but that ICE 2.0 estimates are 50-75% lower than ICE 1.0 for interruptions lasting more than 10 hours.[12] As can be seen in Table 4-3, the decrease in value for non-residential customers between ICE 1.0 and 2.0 is in line with the expected reduction in value as described by Berkeley Labs.

Figure 4-5 provides the comparison in the difference between ICE 1.0, shown in the blue line, and ICE 2.0, shown in the orange line, for all DTE customers over different outage durations. The chart demonstrated that the primary difference in the cost of an outage is driven by the non-residential customers. Section 4.2.3 includes a similar comparison analysis with ICE 2.2.

[12] (Lawrence Berkeley National Laboratory and Resource Innovations, 2025)

Figure 4-5: Difference in Cost of Interruption between ICE 1.0 and 2.0 for Residential and Non-residential DTE customers



4.2.2 C&I Customer Clustering Approach

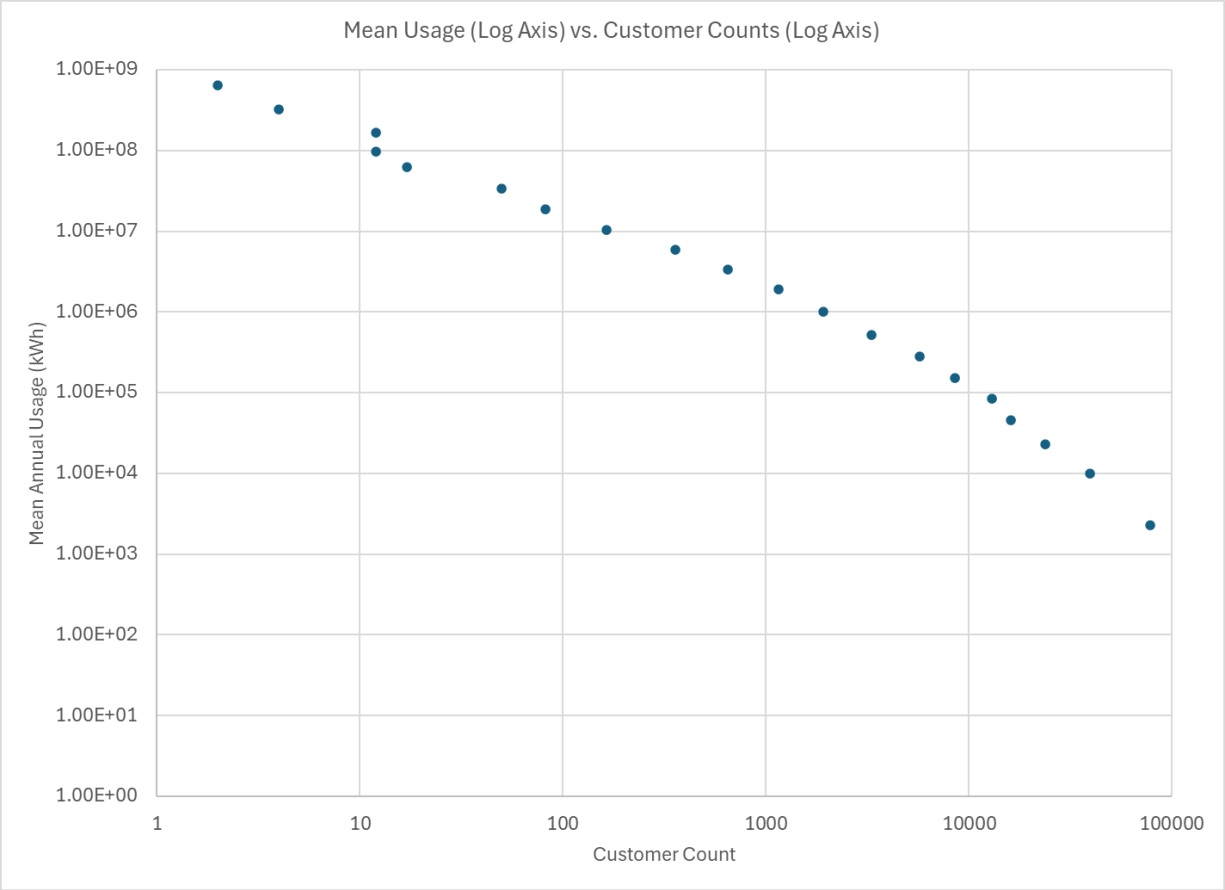
As described above, the ICE Calculator 2.0 defines the cost of an outage for a C&I customer based on the customer's annual kWh usage. DTE provided 1898 & Co. with each C&I customer's annual kWh usage for 2024, and 1898 & Co. utilized this data to map customers to an appropriate annual usage value.

Conceptually, the updated ICE Calculator could enable the consideration of each individual C&I customer's annual usage in evaluating outages. Taking this approach would require significant computational effort and increased modeling complexity to extract values for each customer for each outage duration. For these reasons, 1898 & Co. used a clustering approach to group DTE's C&I customers into representative, relatively homogeneous clusters.

After statistically evaluating options for the number of C&I clusters, 1898 & Co. determined that 20 clusters provided sufficient granularity for evaluating the cost of non-residential outages. This number of clusters represents a reasonable balance between accurately capturing variation in customer usage and maintaining a manageable number of groups for analysis.

1898 & Co. developed the groups by applying k-means clustering to the C&I customer annual kWh usage values for 2024. This clustering approach produced the groups shown in Figure 4-6. In this scatterplot, each dot represents a C&I customer group. The x-axis provides the number of customers within the customer cluster, while the y-axis provides the group's appropriate annual usage value. Given the large ranges for customer count and annual usage, the graph's axes are shown on a logarithmic scale.

Figure 4-6: Results of Clustering C&I Customer Annual kWh Usage



For each of these 20 customer groups, 1898 & Co. extracted non-residential cost of interruption values based on the customer group annual usage and various outage durations from the ICE 2.0 estimator.

4.2.3 Phase 2 of ICE Calculator 2.0 (ICE Calculator 2.2)

On February 26, 2026, Berkeley Labs released Phase 2 of the ICE calculator, referred to as ICE 2.2. This phase expanded the survey results to include more utilities and a larger number of responses. With each new phase of the ICE calculator, the cost of interruption values are updated to reflect additional survey data.

With the addition of the new survey information collected for ICE 2.2, Berkeley Labs updated the customer damage functions to produce new results for the cost of interruption in ICE 2.2. Table 4-4 provides a comparison that Berkeley Labs compiled outlining the estimated differences in the cost of interruption between residential and non-residential customers between ICE 2.0 and ICE 2.2.

Table 4-4: Difference in cost per event between ICE 2.0 and ICE 2.2[13]

Duration of Interruption Event	Residential Cost per Event: % Change Relative to ICE 2.0	Non-residential Cost per Event: % Change Relative to ICE 2.0
2 hours	-2%	+19%
8 hours	-2%	+18%
24 hours	-2%	+4%

As shown in Table 4-4, the difference between the cost of interruption per event is small for residential customers and is estimated to be on average 2% less in value for ICE 2.2. However, for non-residential customers the cost of interruption for longer

[13] (Updates to the Interruption Cost Estimate (ICE) Calculator: Key Differences Between Version 2.0 and 2.2, February 2026)

duration outages has been increased by 19% and 18% for a 2 and 8 hour outage respectively in ICE 2.2.

To understand how the updates to phase 2 of the ICE calculator (ICE 2.2) will impact the cost of service interruption for DTE customers, 1898 & Co. calculated the monetized CMI for different duration outages using the DTE customer base. The results of this analysis are shown in Figure 4-7:. As shown in Figure 4-7:, the ICE 2.2 values are higher than both ICE 2.0 and 1.0 for 2 hour outages and less. At 4 hours, the cost of an outage for ICE 1.0 and 2.2 are close in value. For outages longer than 4 hours, ICE 2.2 is lower than ICE 1.0 but higher in value when compared to ICE 2.0

Figure 4-7: Comparison of ICE 1.0, 2.0, and 2.2 for DTE Customers

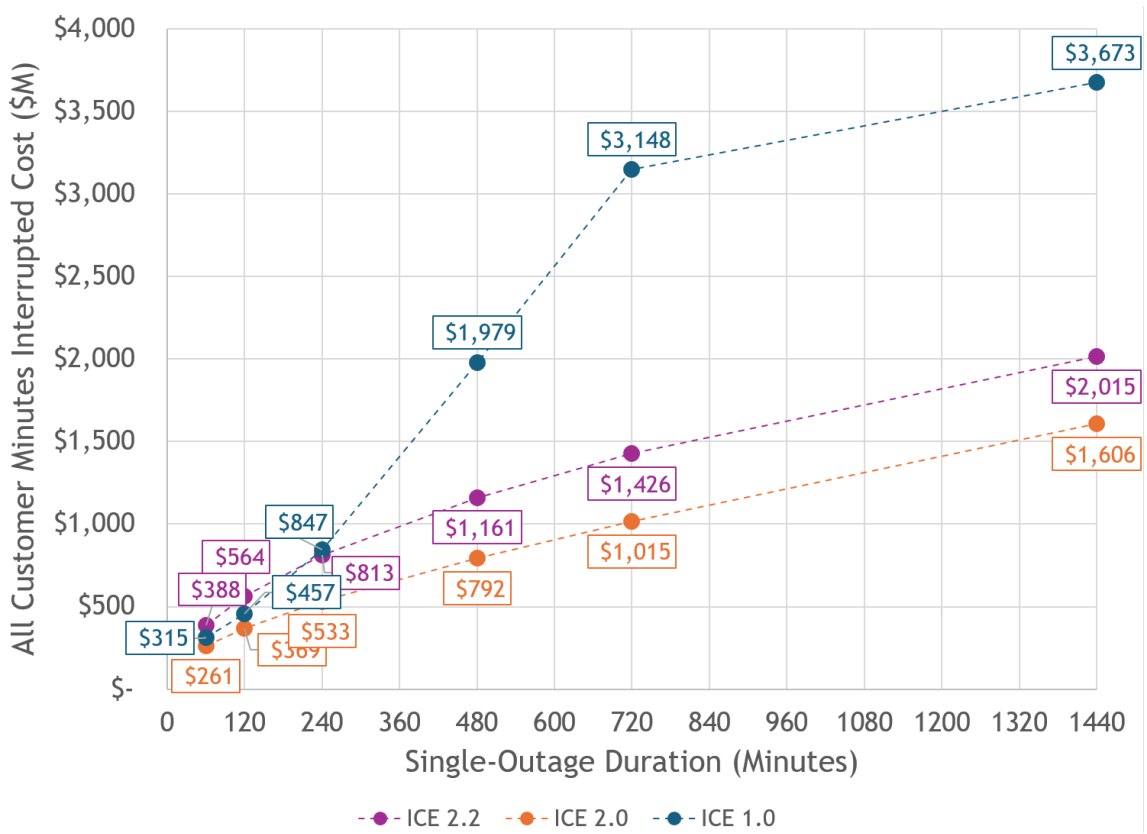


Table 4-5 below compares the difference in the cost of an outage for different durations between ICE 2.2 and 2.0. This shows that ICE 2.2 for the DTE customer profile is anywhere from 25% to 53% higher across the different durations. Of

important note is that outages less than 2 hours are roughly 50% higher in value when using ICE 2.2.

Table 4-5: Difference in cost of interruption between ICE 2.0 and 2.2 for DTE customers

Outage Duration (Minutes)	Estimated Customer Cost ($M)		
	ICE 2.2	ICE 2.0	Delta Between 2.0 and 2.2
60	$387.83	$261.06	49%
120	$564.02	$368.99	53%
240	$812.82	$532.76	53%
480	$1161.49	$791.99	47%
720	$1426.08	$1015.44	40%
1440	$2014.63	$1605.90	25%

Due to the large increase in the value of longer duration of outages for DTE customers, 1898 & Co. estimates that there is potential to increase available benefits when using ICE 2.2 across the DTE programs. In other words, the increased value of an outage for DTE customers could improve the available benefits and the BCRs for all the investment programs discussed in this report. This will be especially true for the DA program as all benefits for this program are related to avoiding customer restoration minutes. For the 2026 analysis, the DA program is receiving reduced benefits due to the change from ICE 1.0 to 2.0 and the Integrated Sequence of Programs explained in section 4.7.1. For the DA program, the use of ICE 2.2 is expected to increase the benefits available to this program which will increase the amount of beneficial investment for DA.

4.3 Resilience and Risk-Based Planning Approach

In the last decade, the frequency and impact of major weather events have grown significantly across the United States. Hurricanes have struck Florida and the Gulf Coast, nor'easters have battered the East Coast, polar vortexes and ice storms have

swept through the Midwest and mountain regions. At the same time, the customer expectations for the availability of the grid have increased dramatically over the last several decades. Decades ago, grid outages were seen as an inconvenience for customers. Today, these outages can cause real economic harm and stress, and even put society's most vulnerable at risk, due to the widespread use of life-saving electronic equipment in people's homes. Additionally, today's society is far more integrated than in the past. The recent supply-chain disruptions following the global pandemic have revealed how interconnected our society and global economy have become. Compounding this challenge is the expected trend towards more dependence on the grid with the acceleration of electrification in applications, such as home heating, oil and gas activity, commercial fleet electrification, and electric vehicle adoption, to name a few. More than ever, today's customers demand that the electric grid be consistently available.

One of the most essential actions electric utilities can take to prepare for major weather events is to make the electric grid more resilient. When the grid can better withstand the impacts of events, everyone benefits. A resilient grid will allow businesses and families to save money because they can get back on their feet more quickly. Proactive investment in grid resilience will also enable utilities to design integrated programs to address all phases of resilience, reducing event-related restoration costs and outage times.

This section of the report outlines a conceptual framework for understanding grid resilience. 1898 & Co. applied the resilience modeling benefit assessment framework to the following DTE programs:

1) PTMM,
2) Small Wire Replacement Program,
3) Subtransmission SCADA,
4) Subtransmission Redesign and Rebuild, and
5) 4.8 kV and 8.3 kV Conversion.

4.3.1 Resilience Definition

The Merriam-Webster dictionary defines resilience as:

1. The capability of a strained body to recover its size and shape after deformation caused especially by compressive stress.
2. An ability to recover from or adjust easily to misfortune or change.[14]

Merriam-Webster elaborates on the definition:

> In physics, resilience is the ability of an elastic material (such as rubber or animal tissue) to absorb energy (such as from a blow) and release that energy as it springs back to its original shape. The recovery that occurs in this phenomenon can be viewed as analogous to a person's ability to bounce back from a jarring setback.[15]

These definitions provide a conceptual understanding of resilience, but additional exploration is needed to understand the term in the context of electric power systems specifically. While the industry has general agreement around the major elements of resilience, the definitions are not identical. Other definitions of resilience from grid stakeholders are:

- **IEEE PES PES-TR83 Report**—Resilience Framework, Methods, and Metrics for the Electricity Sector: The ability to protect against and recover from any event that would significantly impact the grid.
- **CIGRE WG C4.47:** Power system resilience is the ability to limit the extent, severity, and duration of system degradation following an extreme event.
- **FERC**: The ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from such events.
- **DOE:** The ability of a power system and its components to withstand and adapt to disruptions and rapidly recover from them.

In a 2013 paper, the National Association of Regulatory Utility Commissioners offered its own definition of resilience in a manner that is simple and easy to understand:

[14] Resilience. (n.d.). Merriam-Webster Dictionary. https://www.merriam-webster.com/dictionary/resilience.
[15] *Id.*

> Robustness and recovery characteristics of utility infrastructure operations, which avoid or minimize interruptions of service during an extraordinary and hazardous event. In other words, it is the gear, the people and the way the people operate the gear immediately before, during and after a bad day that keeps everything going and minimizes the scale and duration of any interruptions.[16]

Before that, the National Infrastructure Advisory Council provided a definition that is often quoted. It states that resilience is:

> The ability to reduce the magnitude and/or duration of disruptive events. The effectiveness of a resilient infrastructure or enterprise depends upon its ability to anticipate, absorb, adapt to, and/or rapidly recover from a potentially disruptive event.[17]

The National Infrastructure Advisory Council definition includes a system's ability to absorb and adapt. Argonne National Laboratory also used these important characteristics in its state and social resilience work. They were also incorporated into Pacific Northwest National Laboratory's work on the resilience impacts of transactive energy systems. The Argonne National Laboratory approach can be used to break resilience into four phases that also align with the National Association of Regulatory Utility Commissioners' elegantly simple description—the difference being that Argonne National Laboratory explicitly includes the ability of the system to recognize and mitigate potential failures before they happen. These four phases are described below:

[16] Keogh, M., Cody Christina, & NARUC Grants & Research. (2013). Resilience in Regulated Utilities. In *https://pubs.naruc.org/pub/536F07E4-2354-D714-5153-7A80198A436D#:~:text=Resilience%20%2Fri%CB%88zily%C9%99ns%2F%20noun%2C%20regulatory,an%20extraordinary%20and%20hazardous%20event*. The National Association of Regulatory Utility Commissioners.
[17] Bush Wes, Grayson Margaret, Berkeley III, A., & Thompson John. (2009). CRITICAL INFRASTRUCTURE RESILIENCE FINAL REPORT AND RECOMMENDATIONS. In *https://www.cisa.gov/sites/default/files/publications/niac-critical-infrastructure-resilience-final-report-09-08-09-508.pdf*. NATIONAL INFRASTRUCTURE ADVISORY COUNCIL.

- **Prepare (Before)**
  The grid is running normally, but the system and its operators are preparing for potential disruptions.
- **Mitigate (Before)**
  The grid resists and absorbs the event until, if unsuccessful, the event causes a disruption.
- **Respond (During)**
  The grid responds to the immediate and cascading impacts of the event. The system is in a state of flux, and fixes are being made while new impacts are felt. This stage is largely reactionary (even if using prepared actions).
- **Recover (After)**
  The state of flux is over, and the grid is stabilized at low functionality. Enough is known about the current and desired (normal) states to create and initiate a plan to restore normal operations.[18]

The definitions of resilience quoted above can be used to form a conceptual framework to better understand and evaluate initiatives to improve grid resilience. This framework is discussed in the following subsection.

4.3.2 Resilience Conceptual Framework

The Resilience Conceptual Framework provided the foundation for resilience-benefit definition and evaluation within the modeling approach. The resilience of a utility system is a function of many factors; however, the two main factors are:

1) the frequency and types of weather events that impact the system, and
2) the vulnerability characteristics of the infrastructure in the system.

For the first factor, more-frequent and more-intense weather events will make grid resilience more challenging. For the second factor, the unique vulnerability

[18] Argonne National Laboratory. (n.d.). *Resilience Measurement Index: An Indicator of Critical Infrastructure Resilience*. https://publications.anl.gov/anlpubs/2013/07/76797.pdf.

characteristics of a utility's system will change the overall outcome of failure in the face of specific weather events.

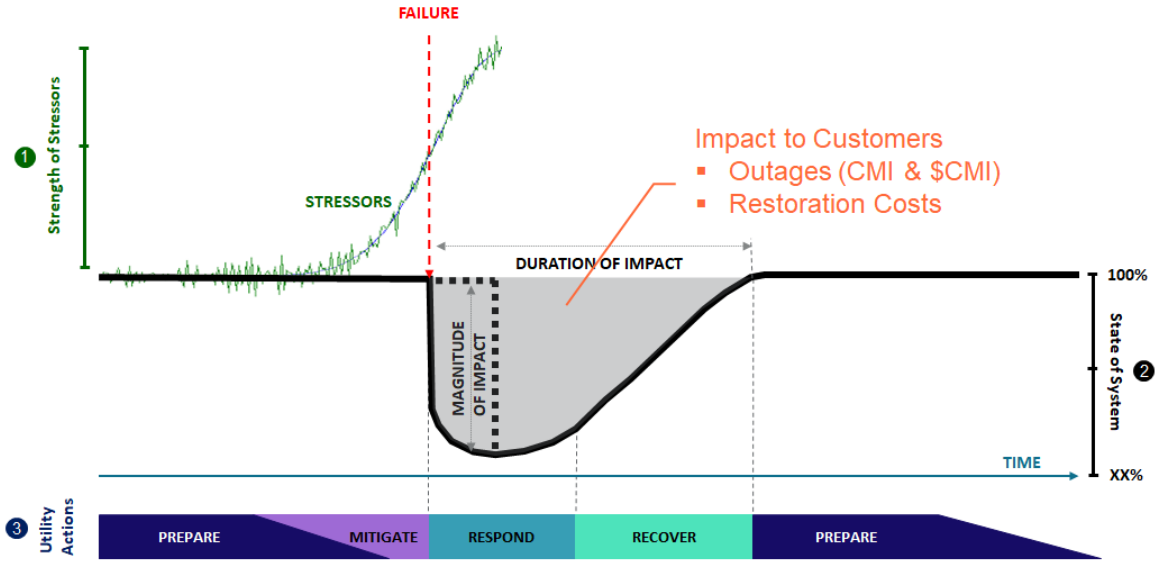
When combined, weather events and system vulnerabilities provide additional challenges for grid resilience. Individual weather events, by their nature, are unpredictable and do not impact an area uniformly. Grid stakeholders could be "lucky" or "unlucky" depending on how the risks posed by a weather event impact the grid. For instance, the electrical system will respond differently to a thunderstorm with pockets of high wind that impact an older, vegetation-dense neighborhood compared to a similar thunderstorm that impacts a newer, suburban neighborhood with underground distribution assets. In the first instance, such a localized thunderstorm may cause significant outages, while having only minimal impact in the second instance, even though the two neighborhoods might be very close in proximity. These two factors, events and vulnerabilities, profoundly impact a grid's measured resilience.

Figure 4-8 presents the Resilience Conceptual Framework that underpinned the modeling approach. As described above, resilience is driven by two primary factors: the frequency and severity of the weather events affecting the system and the vulnerability characteristics of the infrastructure that make up the system. The figure shows how these two factors interact to produce system failures and customer impacts when weather-related stressors exceed the strength of the existing system. The figure also illustrates how utility actions, including preparation, mitigation, response, and recovery, affect the extent of those customer impacts, specifically their magnitude and duration.

Finally, the figure shows that resilience-related investment activities can improve system performance by reducing the severity of these impacts. Depending on the type of investment activity, resilience value may be created by helping the system better withstand major event stressors, reducing the magnitude of the service disruption after failure occurs, or shortening the time required to recover and return to normal operating conditions. As a result, the benefit of resilience-related investment activity

stems from reduced outage consequences and reduced restoration-related costs over the life of the infrastructure.

Figure 4-8: Resilience Conceptual Framework



4.3.3 Resilience Model Overview

The Resilience Event Simulation model estimated the benefits of investment activities, such as asset replacements and inspections, which reduce the impacts of major weather and resilience events on the distribution system. It is based on the resilience conceptual framework described above. The model utilized a resilience-based planning approach to simulate how the DTE system would perform under a wide range of future weather events and to quantify the benefits of investment activities that improve system performance during those events. The modeling framework incorporated historical weather event data, weather-event simulation, system-vulnerability characteristics, and asset-level investment assumptions to evaluate how investments changed outage outcomes and restoration performance under stressed conditions.

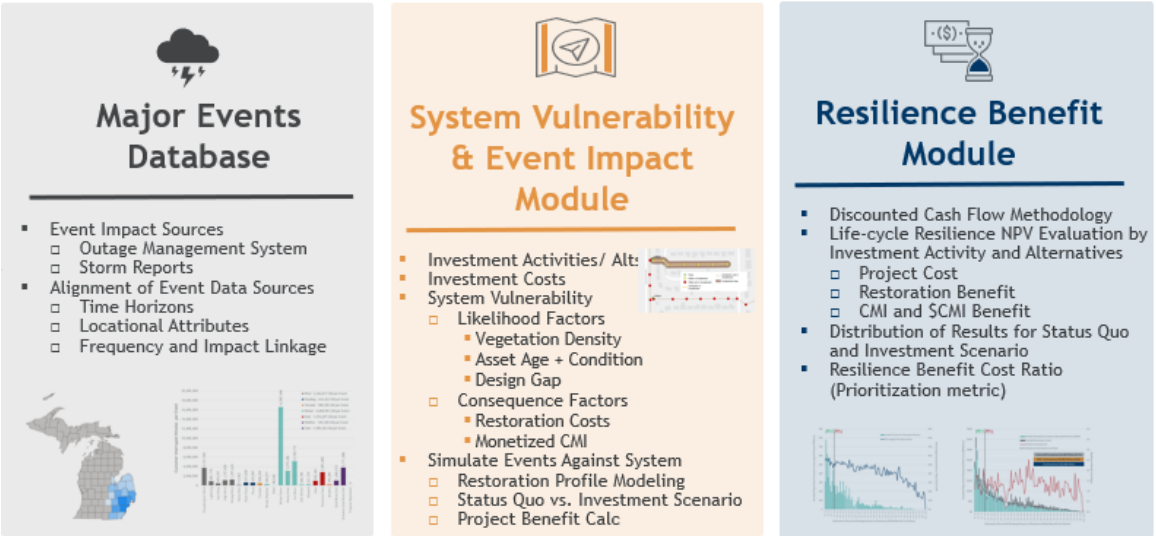
The approach calculated resilience-related benefits for each investment activity (protection-zone or similar element of the system) in each of two scenarios. The first

is a Status Quo scenario in which no proactive investment activity occurred, and the protection zone continued to operate as previously constructed. The second is an Investment scenario in which a proposed, proactive investment activity occurred, such as a rebuild or inspection with equipment replacements and upgrades. For each scenario, the model estimated the distribution of weather-event-induced outcomes, including the resulting customer outages, outage durations, restoration costs, and other resilience-related consequences. The benefits of the investment activity are the differences in outcomes between the Status Quo and Investment scenarios, measured as the avoided resilience consequences attributable to the investment.

Within the modeling framework, the Resilience Event Simulation Model estimated the weather-event-related benefits of investment activities. These benefits are calculated using simulated, future weather events and asset-level representations of system performance or vulnerabilities under stress. When investment activities also provided blue-sky (that is, non-weather-event-related) benefits, such as reduced equipment failure risk under normal operating conditions, the weather-event-related benefits described here were combined with the blue-sky benefits derived from the Equipment Failure Mitigation Model, as described in Section 4.4.

Figure 4-9 provides an overview of the Resilience Event Simulation Model used to calculate the restoration cost reduction and the CMI reduction (the benefits) of resilience-related investment activities. The model has three primary components: the Major Events Database, the System Vulnerability & Event Impact Module, and the Resilience Benefit Module. Collectively, these components integrated weather-event data, system-vulnerability characteristics, and investment activity assumptions to quantify the resilience benefits provided by the evaluated investment activities. The following three sections describe each component in greater detail.

Figure 4-9: Resilience Event Simulation Model



4.3.3.1 Major Events Database

Since an investment activity's associated reduction in restoration costs and CMI depended on the frequency and severity of future weather events that will impact the DTE service area, the Resilience Event Simulation Model begins by developing a "universe" of major weather events that could impact DTE's service area. The Major Event Database provided a high-level, expected impact on the system from each of the NOAA-defined, major weather events. The major events database included the following information:

- Weather Event Type,
- Frequency of the event, for each county section of DTE's service area,
- Average impact, in CMI terms, for each event based on historical outage records.

In developing the database, 1898 & Co. utilized historical weather event information from NOAA's weather event database (1998-2025) and DTE's historical outage records (2007-2025) to ascertain the frequency and impact of events, as outlined in Section 3.0.

4.3.3.2 System Vulnerability & Event Impact Module

The System Vulnerability & Event Impact Module developed a list of potential resilience-related investment activities, their costs, and their effectiveness in mitigating weather-event-related costs. The evaluation comprehensively evaluated multiple investment activities, e.g., overhead rebuilds, pole and pole-top inspections, across nearly the entire system. Investment activities were defined and evaluated at the protection zone (or similar) level. The module also estimated the costs of each resilience-related investment activity.

The module evaluated the impact of major weather events on the system. Specifically, it identified, from an asset-centric perspective, that each protection zone's likelihood of experiencing a failure during each of the weather events included in the Major Events Database. This protection-zone-level likelihood was based largely on asset types, quantities, and ages, along with other condition information, e.g., vegetation density. This reflects the primary driver of protection-zone failures during weather events; wind blows vegetation (and other debris) into assets, placing additional stress on assets, leading to individual structure and then protection-zone failures.

The module estimated the restoration costs associated with the specific failures and calculated the CMI impact. The model calculated weather-event restoration costs using asset-level, planned-replacement costs scaled to reflect the additional costs associated with reactive replacement. The cost scalars were based on historical weather-event data, expected inventory constraints, and the anticipated blend of DTE and non-DTE crews required for the various asset types and weather events. For each weather event, asset-level restoration costs were aggregated up to the protection-zone (or similar) level. Recall that, for the distribution system, investment activities were organized at the protection zone level.

The module calculated the expected duration of an outage using a restoration curve that identified the overall length of an outage based on the total number of protection zones experiencing the outage. The greater the number of protection

zones experiencing the outage, the longer the overall outage duration. After identifying the overall outage duration, individual-protection-zone outage durations were assigned, with higher-priority zones (i.e., those with more customers and those higher in the electrical hierarchy) receiving shorter durations and lower-priority zones receiving longer durations. In the Investment scenario, outages had shorter durations, when compared to outage durations in the Status Quo scenario. In the Investment scenario, investment activities reduced the number of protection zones experiencing an outage due to an individual weather event, leading to shorter overall outage durations and correspondingly shorter protection-zone-outage durations.

A protection zone's outage duration was then multiplied by the zone's numbers and types of affected customers to obtain a CMI value for the outage. Finally, the CMI for each combination of protection zone, scenario and weather event was monetized using the ICE Calculator values corresponding to the outage duration and customer types.

At this point, the module calculated storm restoration and CMI costs for each protection zone (or similar), in both the Status Quo and the Investment scenarios, for each of the NOAA-derived weather events. The difference between an investment activity's weather-event Status Quo and Investment costs was the benefit of the activity in the presence of that weather event. The module's final output was this collection of weather- and investment-activity-specific Status Quo and Investment scenario costs.

In summary, the System Vulnerability & Event Impact Module utilized a robust and sophisticated set of data and algorithms to model the benefits of each resilience investment activity in the presence of each weather event.

4.3.3.3 Resilience Benefit Module

The benefits of resilience investment activities were driven by the frequency, type and location of future weather events. Each weather-event type had a range of potential likelihoods and consequences. For this reason, the Resilience Benefit Module employed Monte Carlo simulation. The Monte Carlo simulation randomly generated

weather events to impact the DTE service area over a number of 50-year weather futures. These random weather events were based on the weather-event frequencies from the Major Event Database. Recall that the database contained the historical record of weather events that have impacted the DTE service area in the past and, therefore, could be expected to impact the service area in the future. The Monte Carlo simulation considered each county individually, generating that county's future weather events based on that county's historical record.

For each randomly generated weather event in each of the weather futures, the Resilience Benefit Module determined the benefits generated by individual investment activities associated with each protection zone (or similar system element) that would have been affected by the weather event. Recall that the benefit of an investment activity was the difference between the associated protection zone's Status Quo scenario costs and its Investment scenario costs.

The Resilience Benefit Module incorporated a discounted cash flow methodology to aggregate the costs and benefits for each investment activity over each weather future's 50-year time horizon. This reflected that future avoided costs are less valuable than the current avoided costs.

Finally, the module consolidated results from the individual weather futures to produce a single, statistical expectation of each investment activity's cost and benefit values. This consolidation captured values from an expected, a high and an extreme weather future, i.e., the 50th, 75th and 95th percentile weather futures. Among the three futures, the majority of the emphasis went to the expected future, while the least emphasis went to the extreme. These key cost and benefit values were utilized within the Plan Development Module to provide a comprehensive, customer-centric, value-driven assessment.

4.4 Equipment Failure Mitigation Modeling Approach

The Equipment Failure Mitigation modeling approach calculates the benefits of replacing existing infrastructure. It utilizes a resilience, reliability, and risk-based planning approach to forecast the probability-weighted consequence of failure for a range of failure types. The failure types are based on how assets fail over their life-

cycle, including inspection-based failures. Consequences are estimated for a range of factors but fall into two main categories:

1) The first category is avoided reactive costs, also called restoration benefits. These are costs avoided by the utility through the replacement of an existing asset, thereby avoiding any remaining material costs of failure associated with the remaining lifespan of that asset.
2) The second category is customer-based outages. This category is the monetization of customer outages in the event of an asset failure based on the ICE calculator described in Section 4.2 above.

The approach calculates each asset's life-cycle reactive costs and customer outage costs for two scenarios. The first is a Status Quo scenario where the asset is not proactively replaced. The second is the Investment scenario in which the asset is upgraded proactively to the new equipment standard. The benefit of replacing infrastructure is the difference between the two scenarios, comparing the avoided resilience, reliability, and risk life-cycle costs of the Investment scenario to the same costs of the Status Quo scenario.

The equipment failure mitigation modeling approach was the sole model used to evaluate the BCA for the following programs:

1) URD Replacement
2) Cable Replacement, and
3) Breaker Replacement

The model was also used to estimate the non-weather event portion of benefits for the following programs:

1. PTMM
2. Small Wire Replacement Program
3. Subtransmission Redesign and Rebuild, and
4. 4.8 kV and 8.3 kV Conversion Programs

For these investments, the weather-related benefits were estimated using the Resilience Modeling Approach (Section 4.3). The non-weather-related benefits, derived from the Equipment Failure Mitigation Model, and the weather event benefits, derived from the Resilience Model, are then combined and normalized as described in Section 4.7. The Communication network BCA leveraged the Probability of Survival approach to analyze replacement of edge devices. The following sub-sections outline the Equipment Failure Mitigation Modeling Approach in further detail. A 40-year-old oil distribution breaker is used as an illustrative example in the approach to demonstrate benefit calculations.

4.4.1 Probability of Surviving

Many of the asset classes on DTE's system are typically replaced before failure-causing outages. This replacement is because the consequence of failure typically exceeds utilities' risk tolerance levels, especially safety risks. For this reason, utilities actively inspect the assets, perform testing, and collect real-time condition information. When assets exceed a condition tolerance, they are proactively replaced based on detailed engineering evaluations, budgeting considerations, and prioritization of needs.

End-of-Life curves can be utilized to approximate the probability of an asset not surviving over time. Each asset class modeled was assigned an Iowa Survivor Curve inside the Equipment Failure Mitigation Model. Figure 4-10 shows an example End-of-Life (Iowa Survivor Curve) for oil distribution circuit breakers. These breakers are expected to have an average service life of 45 years, as modeled. Figure 4-11 shows the approach to calculate the annual probability of not surviving for a 40-year-old oil distribution circuit breaker asset.

Figure 4-10: Example Survivor Curve for Oil Distribution Circuit Breakers

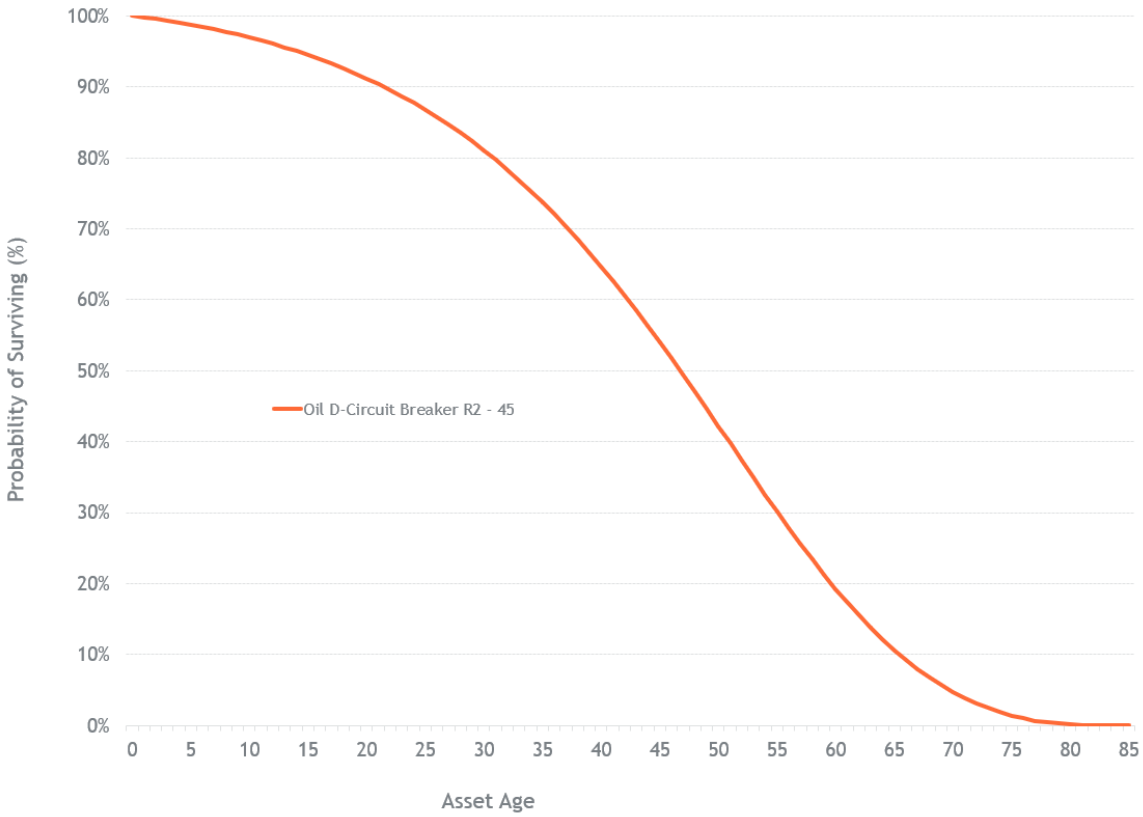
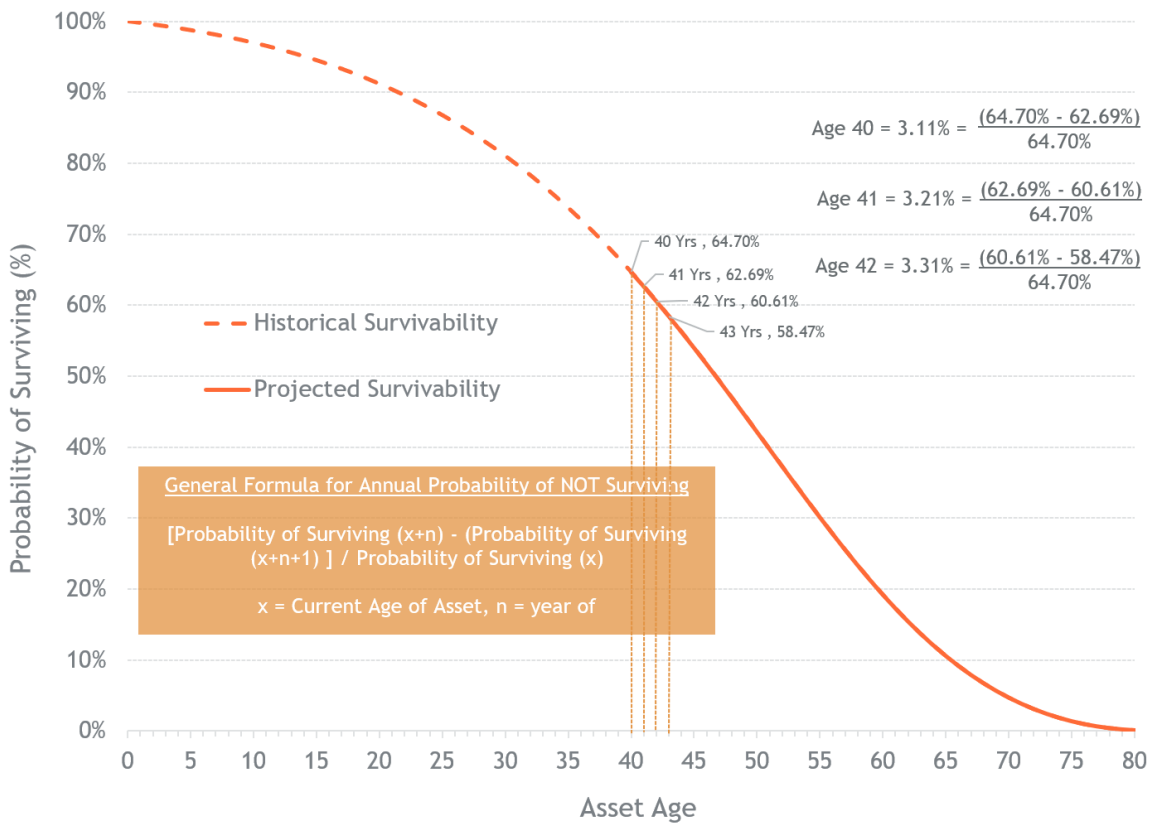


Figure 4-11: Annual Probability of Not Surviving Example - Oil Distribution Circuit Breaker

Benefits Modeling Approach



The survivor curves allow for the calculation of the annual probability of an asset not surviving over time. The curves produce a probability density function where the total probability is 100%. The curves are then used to forecast the probability of an asset not surviving at the asset's age. Figure 4-12 shows the annual probability of not surviving for a range of ages for an oil distribution circuit breaker based on the mathematical approach shown in Figure 4-11. The figure illustrates that, as assets get older, the 100% probability of not surviving each successive year is distributed over fewer years, thereby increasing the annual probability of failure for older assets.

Figure 4-12: Survivor Curves to Annual Probability of Not Surviving Profiles for Oil Distribution Breakers

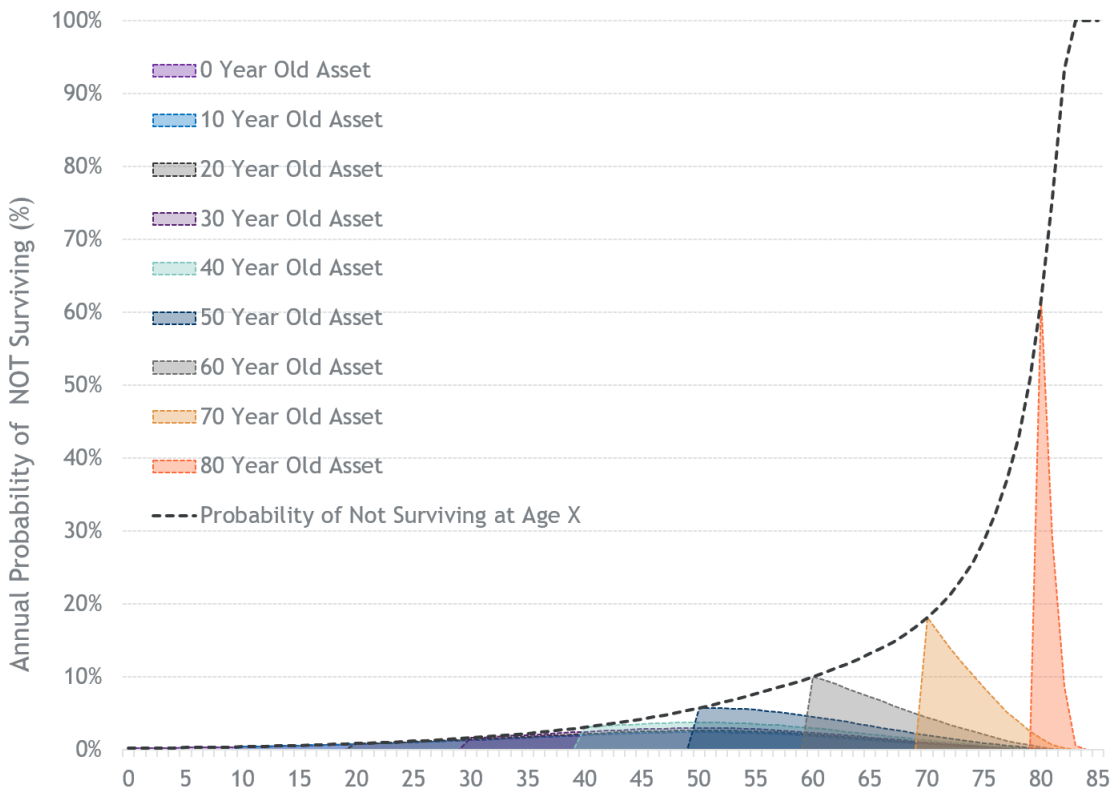
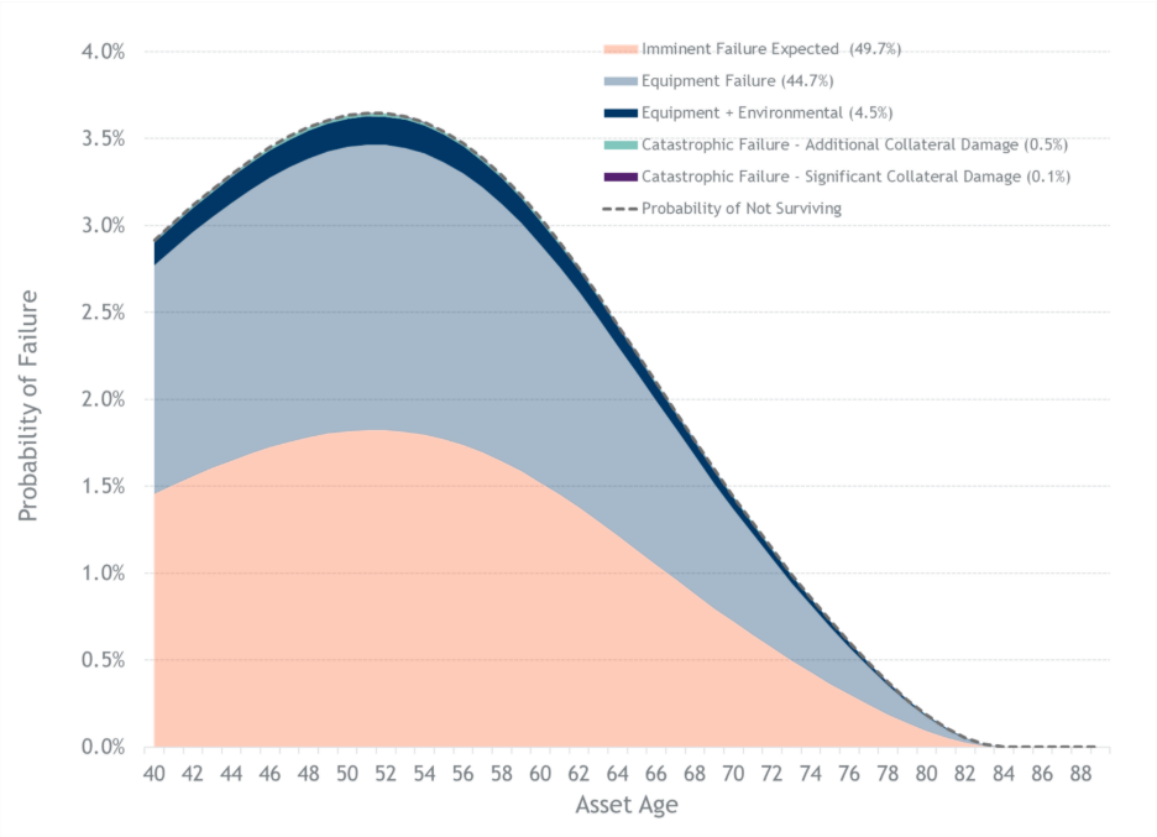


Figure 4-12 also shows the probability of not surviving at each age (Probability of Not Surviving at Age X). Each asset class survivor curve produces different representative failure rate profiles as an asset ages. Using the assigned survivor curve, the Equipment Failure Mitigation model calculates the probability of not surviving for each asset included in the evaluation.

4.4.2 Failure Types and Probability of Failure

The previous section, Section 4.4.1, described the approach to forecast an asset's annual probability of not surviving over time. Assets regularly fail to survive a year for a wide range of reasons. For example, a breaker may be replaced due to a failed inspection or after a catastrophic failure. 1898 & Co. has developed a library of failure type profiles for T&D infrastructure assets. That library is codified within the Equipment Failure Analytics Engine, a proprietary and confidential software developed by 1898 & Co. Figure 4-13 illustrates the probability of failure profile for each failure type of an example 40-year-old oil distribution circuit breaker.

Figure 4-13: Failure Types and Probability of Failure for 40-Year-Old Oil Distribution Breaker



For oil distribution circuit breakers, the most common expected failure type is imminent failure expected, where the breaker's condition (known through inspections and testing) does not meet the utility's risk tolerance. As the figure shows, this failure type makes up approximately 50% of how the oil circuit breaker is expected to fail.

4.4.3 Consequence of Failure

For each failure type, the risk framework library inside of the Equipment Failure Mitigation Model includes a range of consequence types based on expected impact should the asset fail. Table 4-6 shows the range of consequence types evaluated, the asset classes that they apply to, and the avoided cost type. The framework puts a monetary value to each of these consequence factors.

Table 4-6: Consequence Types and Asset Class

Consequence	Avoided Cost Type	Circuit Assets	Substation Assets
Customer Outages	Customer Outage	✓	✓
Equipment Failure Costs	Reactive	✓	✓
Oil Spill Remediation	Reactive	✗	✓
Collateral Damage	Reactive	✗	✓

4.4.3.1 Customer Outage Impact

One of the main consequences of failure across all asset classes is the impact on customers. When assets fail, the protection schemes activate to protect the system against fault currents, limiting customer outages to zones of protection. These protective interventions cause customer outages for the time it takes to restore the system. The relationship between assets and customers was established for all circuit assets as outlined in Section 2.3 above.

For each asset and failure type, the expected duration of the outage was estimated based on typical restoration times. For example, the expected duration to replace a breaker during a typical equipment failure is approximately 1 hour, since crews are likely to be readily available and the replacement work is straightforward. The duration of a catastrophic event is longer, as the potential damage to the breaker itself can require more effort from crews to remove, clean up, and replace. The outage duration for a catastrophic event is estimated at approximately 4 hours for breakers. Based on the expected duration of each failure type for each asset and expected customers impacted (Section 2.3), while also accounting for customer type, the approach calculates the risk-weighted CMI for each asset. This risk-weighted CMI is monetized using the ICE Calculator (see Section 4.2) to estimate each asset's risk-weighted $CMI over time.

4.4.3.2 Equipment Failure Costs

When assets fail before being proactively replaced, it creates an urgency to repair or replace the asset to minimize the impact on the customer. The level of urgency is

generally proportional to the failure types outlined in Figure 4-14 below. This urgency results in a level of effort that is not without cost. These additional costs are captured under the category of equipment failure costs. The magnitude of these costs is different depending on the failure type. Crews are generally available during "normal operations" (non-storm) failure types, but capital efficiencies are lost as the mobilization is generally for one asset. During the various weather events or catastrophic failure types, overtime is generally authorized to restore electric power as soon as possible. During these impactful events, crews from neighboring utilities are often utilized to minimize the impact to the customer. These costs can be significant. For these types of events, it is not uncommon for the cost of replacement to be more than double the cost of proactive replacement. Equipment Failure costs were estimated for all asset categories and all failure types. Combined with the annual probability for each failure type, these values are used to calculate the failure cost profiles for all assets.

4.4.3.3 Oil Spill Remediation Costs

Oil is a vital fluid for the functioning of specific substation assets (e.g. oil-filled breakers). The new equipment standard for circuit breaker insulation is gas or vacuum, depending on voltage class. While rare, oil-filled breaker assets can fail with consequences that include significant oil leaks or oil spattering over a sizeable area. This risk increases as the asset ages. Should an asset fail where oil is not contained, the oil spills must be addressed through remediation. The higher the asset capacity rating, the larger the potential remediation costs (i.e., more oil for insulation purposes).

Oil spill remediation costs were probabilistically factored into the analysis for oil-filled breakers. The approach assumed replacement of oil-filled breakers with a vacuum circuit breaker, eliminating oil remediation risk altogether. The resilience, reliability, and risk benefits are twofold: first, decreasing the condition-based age for the asset; and second, eliminating oil spill risk.

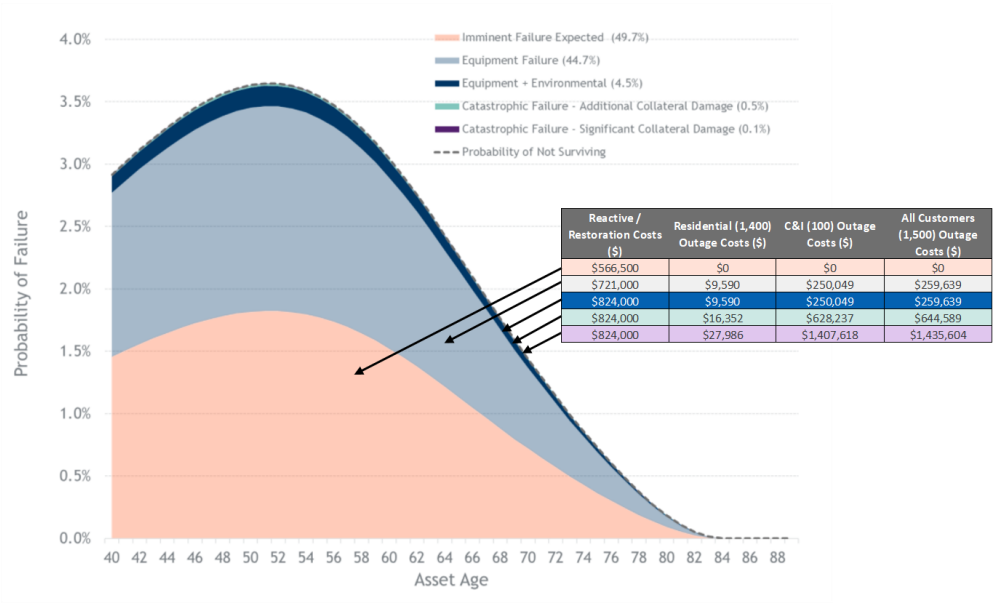
4.4.3.4 Collateral Damage

Substations are an area of high energy transfer. High energy in combination with an asset failure can result in a catastrophic failure that may result in fire or explosion, especially with arcing. The fire or explosion is generally not contained to the asset that failed. The result is collateral damage to other assets within the substation and, in rare circumstances, property outside the substation's boundary. These collateral damage costs can vary significantly from thousands to millions of dollars. As assets age, the probability of this type of failure increases. While statistically rare, these high to extreme costs are factored into the analysis for substation assets.

4.4.4 Status Quo Resilience, Reliability, & Risk Profile

As discussed above, the evaluation calculates the resilience, reliability, & risk cost profile over time for two scenarios, the Status Quo Scenario, and the Investment Scenario. The Status Quo scenario assumes the asset is not proactively replaced and could incur risk costs over time. To calculate the Status Quo Resilience, Reliability, & Risk costs over time, the probability of failure for each failure type is multiplied by the cost consequence for each failure type. Figure 4-14 depicts this approach for a 40-year-old oil distribution breaker example with approximately 1,500 customers downstream. The figure shows the number of residential and C&I customers for this example. Figure 4-15 and Figure 4-16 show the Status Quo Resilience, Reliability, & Risk costs for reactive and restoration costs and customer outage costs, respectively. The profiles are based on multiplying the probabilities of failure in Figure 4-14 by the economic consequence values and applying the escalation and discount rate from above. Figure 4-15 and Figure 4-16 each depict the percentage of total costs for each failure type. Figure 4-17 is the sum of Figure 4-15 and Figure 4-16 for each year, and shows the total resilience, reliability, & risk costs for the 40-year-old oil distribution breaker.

Figure 4-14: Status Quo Resilience, Reliability, & Risk Calculation 40-Year-Old Oil Distribution Breaker



Reactive / Restoration Costs ($)	Residential (1,400) Outage Costs ($)	C&I (100) Outage Costs ($)	All Customers (1,500) Outage Costs ($)
$566,500	$0	$0	$0
$721,000	$9,590	$250,049	$259,639
$824,000	$9,590	$250,049	$259,639
$824,000	$16,352	$628,237	$644,589
$824,000	$27,986	$1,407,618	$1,435,604

Figure 4-15: Status Quo Reactive Costs Profile - 40-Year-Old Oil Distribution Breaker [Present Value $]

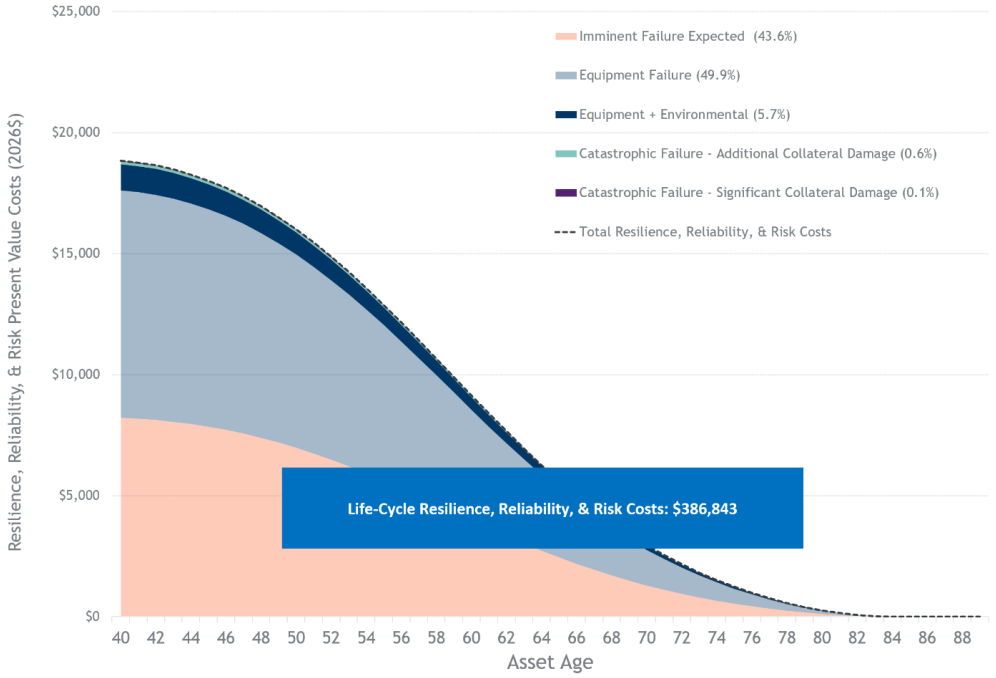


Figure 4-16: Status Quo Customer Costs Profile - 40-Year-Old Oil Distribution Breaker [Present Value $]

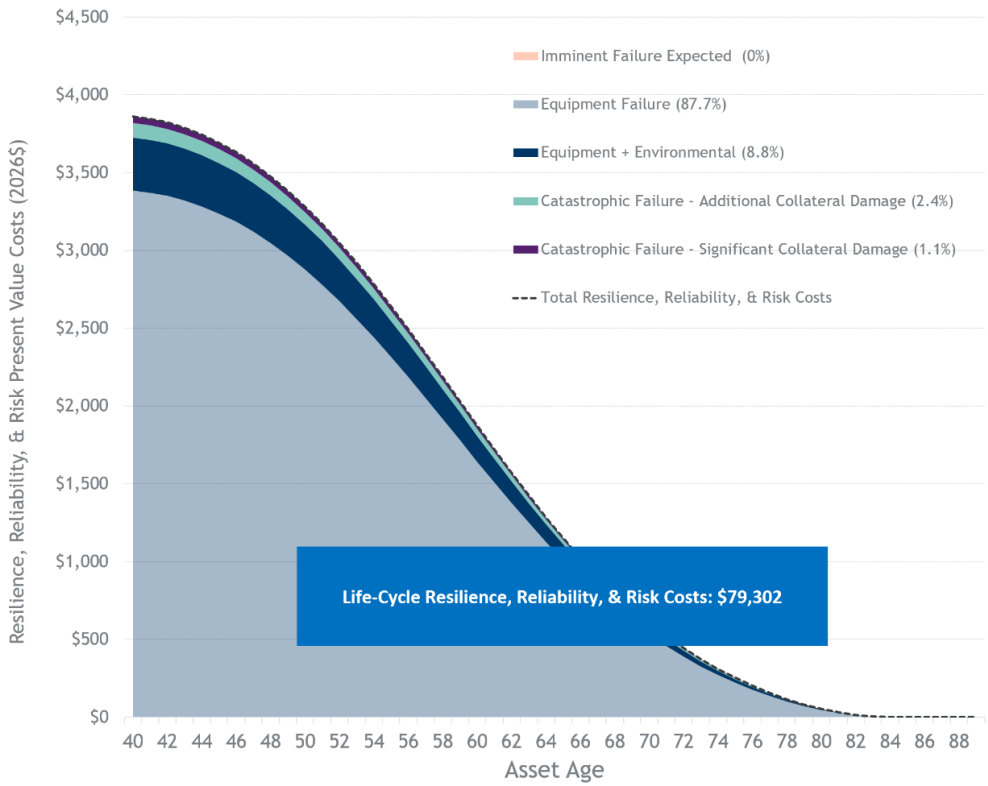
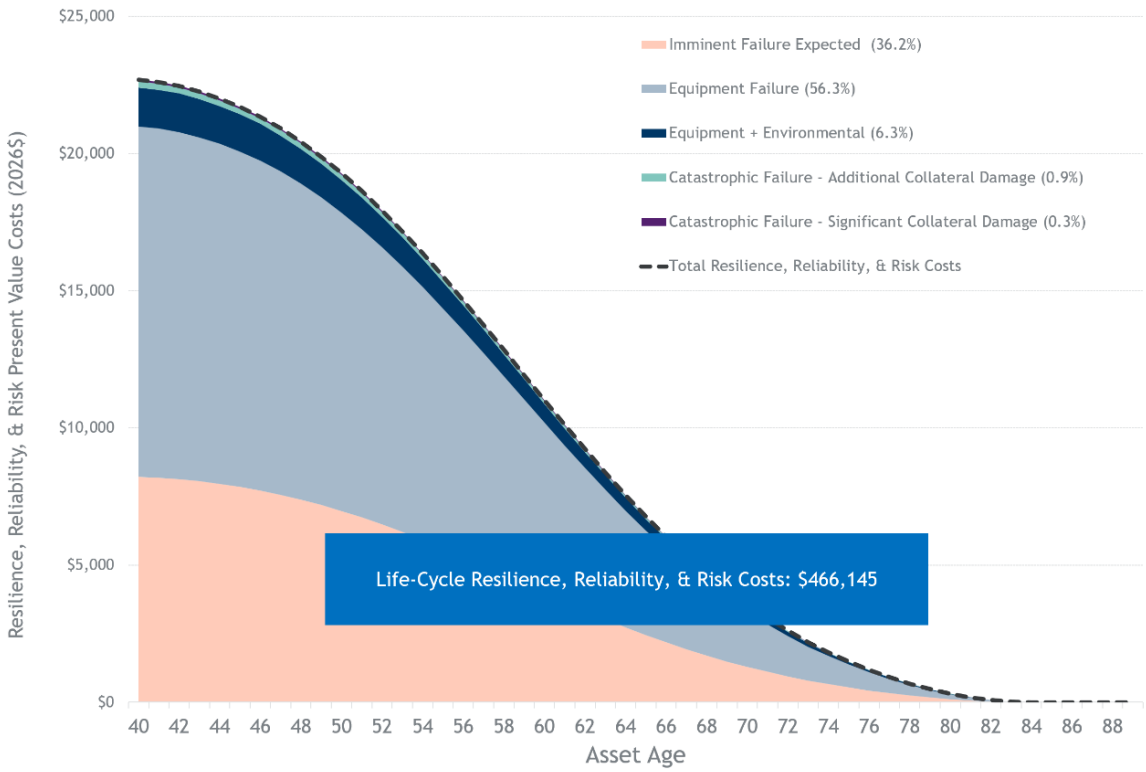


Figure 4-17: Status Quo Total Costs Profile - 40-Year-Old Oil Distribution Breaker [Present Value $]



4.4.5 Avoided Resilience, Reliability, & Risk Cost-Benefit Calculation

The second scenario evaluated for each asset is the Investment Scenario. This scenario assumes the asset is replaced. By replacing the asset, the near-term failure probabilities decrease since the asset is now 0 years old. In some cases, the failure types change with the replacement, such as wood cross arms that are replaced with fiberglass cross arms. The avoided resilience, reliability, & risk benefit for infrastructure upgrades is the difference between the Status Quo and Investment scenarios.

Figure 4-18 and Figure 4-19 show the failure probabilities of the Status Quo and Investment scenarios for the example 40-year-old oil distribution breaker. Over the next 50 years, for the 40-year-old oil distribution breaker, there is a 100% probability of not surviving. If the oil distribution breaker is replaced, there is approximately a

57.8% probability of not surviving over the same 50-year time horizon. The figures also show the life-cycle probabilities for each failure type.

Figure 4-18: Status Quo Probability of Failure Profiles

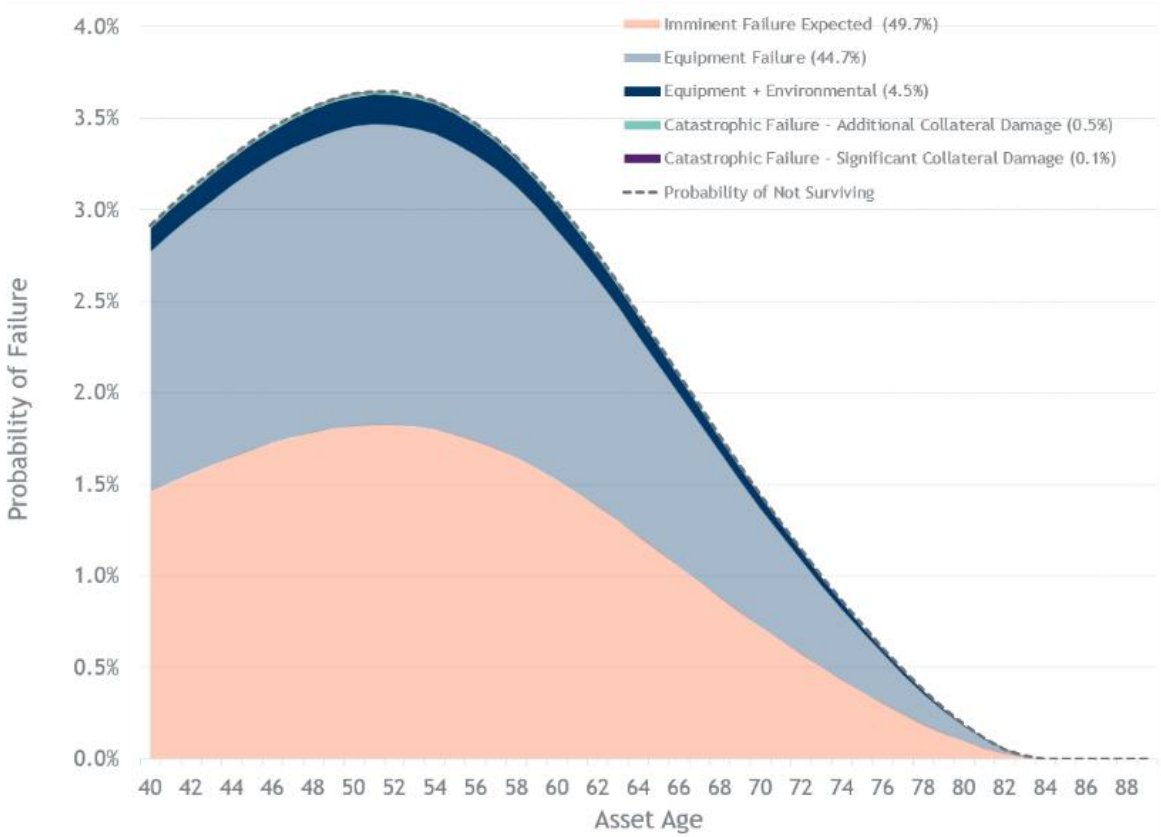


Figure 4-19: Investment Scenario Probability of Failure Profiles

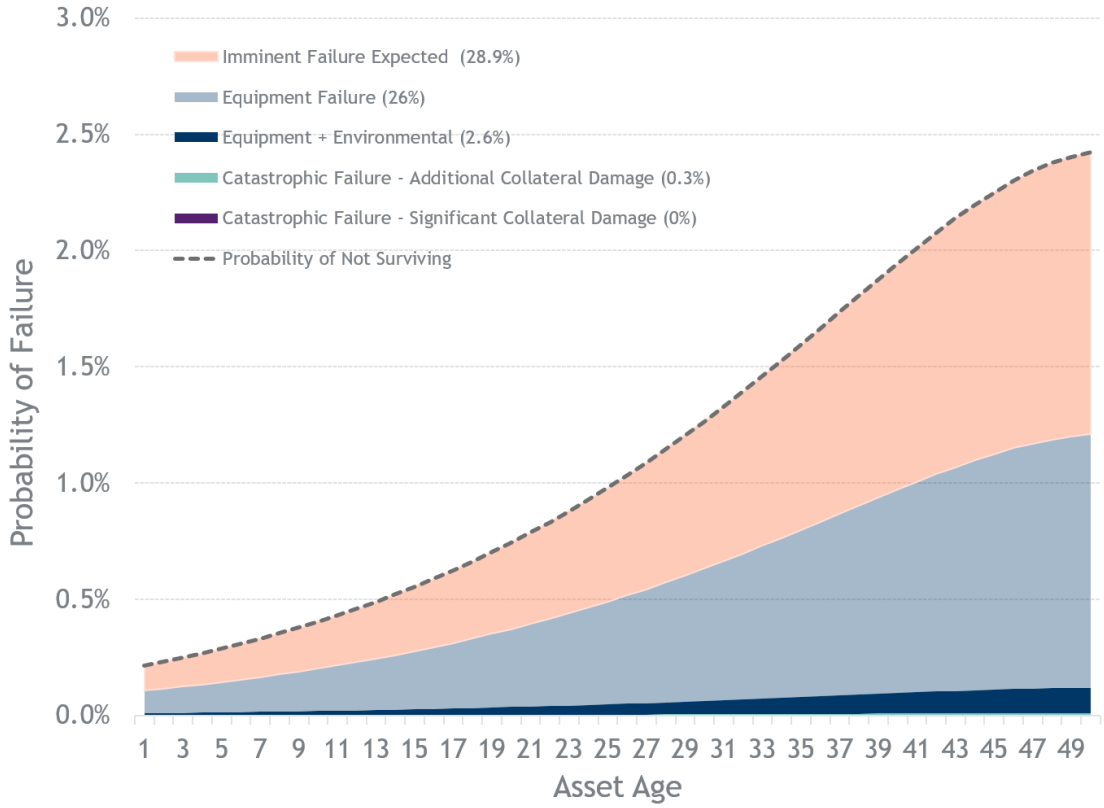


Figure 4-20 and Figure 4-21 show the companion resilience, reliability, and risk cost profiles for the Status Quo and Investment scenarios. Figure 4-22 shows the total values from Figure 4-20 and Figure 4-21 and the annual difference (Status Quo minus Investment). The annual difference is the avoided annual costs for replacing the 40-year-old oil distribution breaker. The life cycle avoided cost benefit is approximately $ 340,166 (present value dollars) for replacing the oil distribution breaker. If the breaker were younger, the annual avoided costs would turn negative sooner and make the project less beneficial.

Figure 4-20: Status Quo Resilience, Reliability, & Risk Cost Profiles [Present Value $]

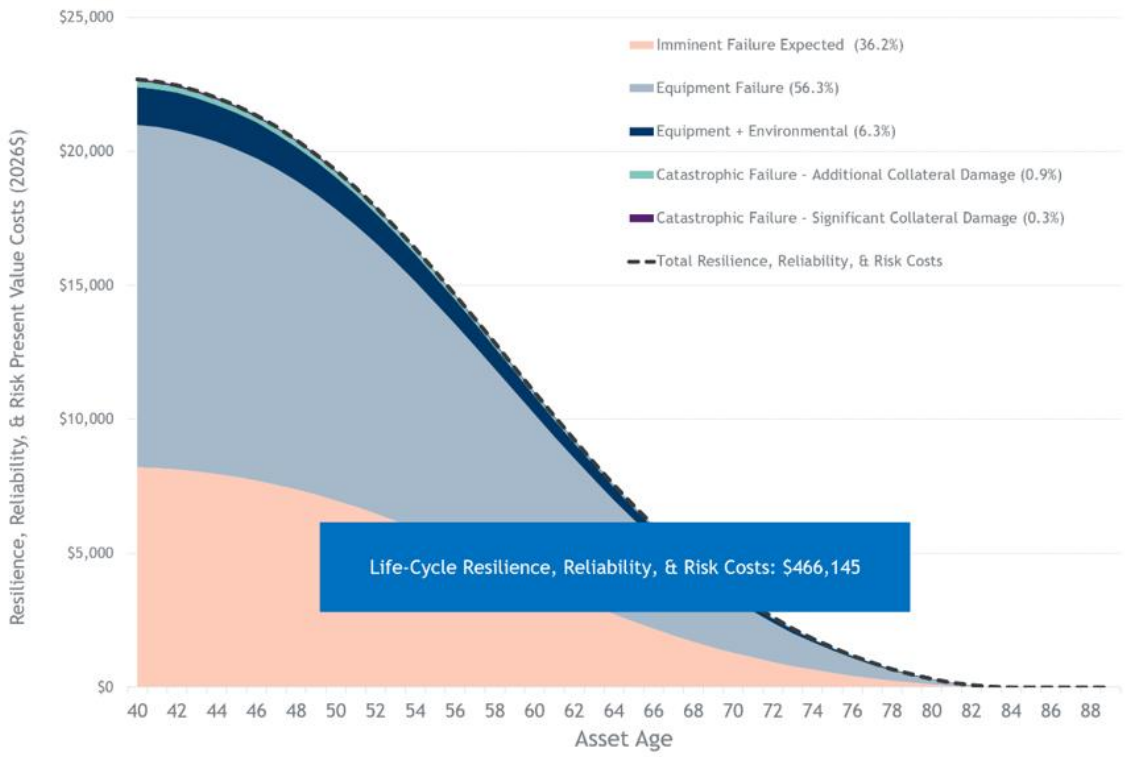


Figure 4-21: Investment Scenario Resilience, Reliability, & Risk Cost Profiles [Present Value $]

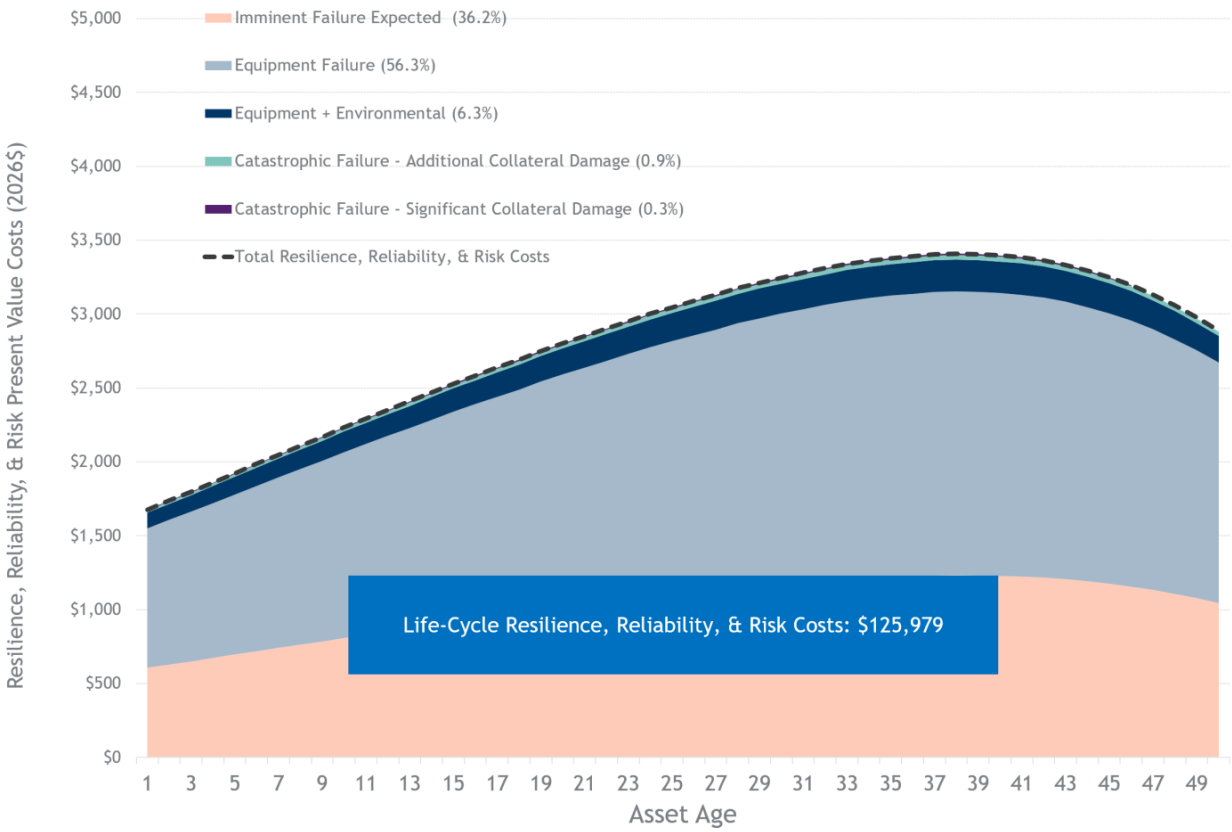
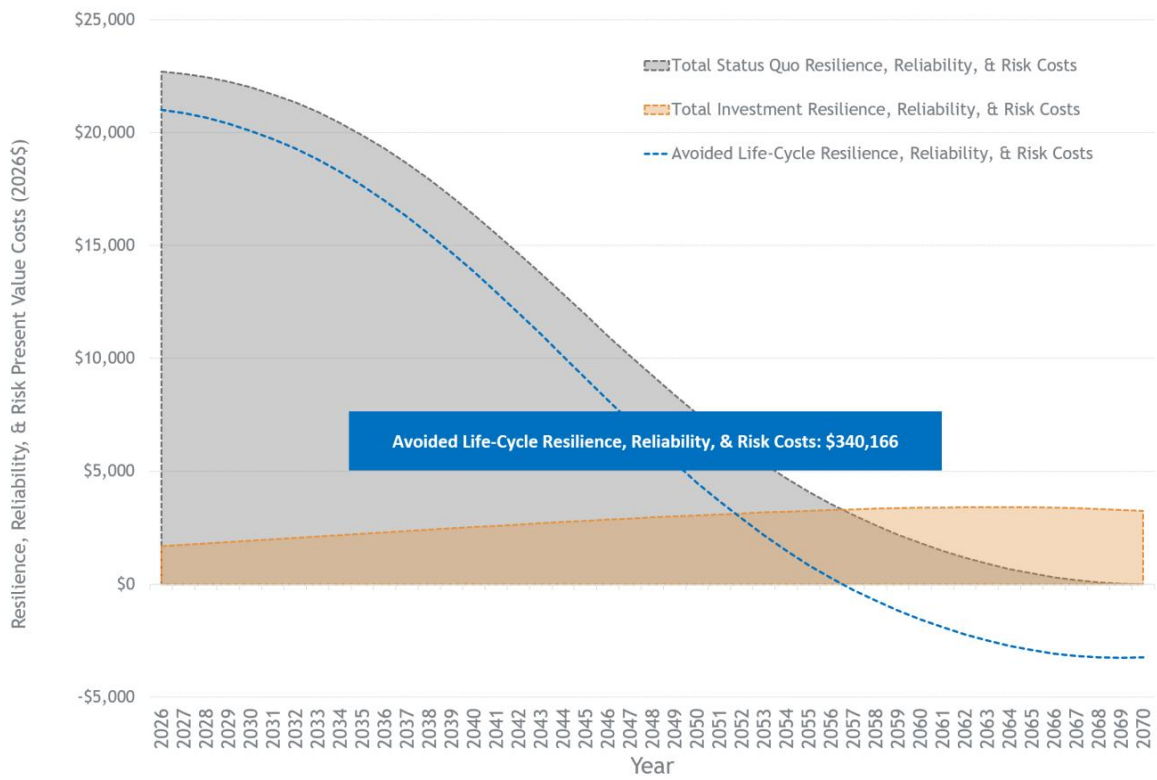


Figure 4-22: Avoided Resilience, Reliability, & Risk Cost-Benefit [Present Value $]



4.5 Outage Mitigation Modeling Approach

The outage mitigation modeling approach calculates the benefits of proposed investments by recalculating historical outage events as if the proposed investments were already in place. The approach is intentionally conservative in that it is grounded in historical outage data and only credits benefits for outages recorded in utility's historical data, instead of considering a full universe of the weather events or climate risk future, as discussed in Section 4.3 Resilience and Risk-Based Planning Approach.

For each outage, the model compares two scenarios. The first is a Status Quo scenario reflecting observed outage performance. The second is the Investment scenario, in which the proposed investments are assumed to be in place. The benefit of the investment is the difference between the two scenarios, measured as avoided

customer minutes interrupted. These avoided outage impacts are monetized using the ICE Calculator based on the customer types affected.

The life-cycle present value of avoided customer outages is calculated by applying escalation and discount rates over the life of the investment. This produces a life-cycle present value of benefits that can be directly compared to investment cost through the Benefit-Cost ratio (BCR).

This approach is used for quantifying benefits of the DA program and evaluates the benefits of the following investment activities:

1. Sectionalization
2. Automate Existing Ties
3. Build New Ties

The following sub-sections describe this modeling approach in further detail.

4.5.1 Prepare OMS Data and Customer Types

As discussed above, the outage mitigation modeling benefit approach is data centric. The core data used for this analysis is the historical outage records provided by DTE (described in Section 2.2). To better represent the current system state, the analysis leverages the most recent 5 years (2021-2025) of DTE's 19 years of outage records. The recent OMS data reflects customer experience under the current configuration of the distribution system, including manual and automated switching capabilities, current crew response practices, and recent investments that impact reliability such as vegetation management and PTMM.

This approach conservatively assumes that future outages will be similar to those observed in the past 5 years. The quantified benefits may understate future outage risk because they are grounded in historical outage data. As a result, they do not account for the possibility of more severe future outages driven by increasing climate risk or extreme weather events in the future.

The analysis leveraged the cause descriptions, device type, and system of the outage for identifying the outages that can be mitigated by investments in distribution

automation. Identifying which outages can be mitigated by DA (and which outages cannot) provides confidence that benefits are not overstated.

As described in Section 2.3, DTE provided customer-type information with database ties to DTE's GIS and OMS. Using this information, 1898 & Co. linked the type of customers impacted on each of the outages in the OMS. This data allows for the monetization of outages using the ICE calculator to evaluate the economic impact of customer outages for different customer types.

4.5.2 Mitigated Outage Calculations

This section outlines the general approach to re-calculating the outage records to quantify customer benefit. The DA program has impact on customer outages in two major ways:

1. Sectionalization
2. Automate Existing Ties & Build New Ties

4.5.2.1 Sectionalization

1898 & Co. calculated the benefits associated with investing in reclosers to increase the sectionalization of distribution circuits across DTE's system. By increasing the sectionalization of a circuit, the customer impact from outages can be mitigated by isolating outage-causing faults using a recloser instead of a breaker or further upstream device. The model recalculates the outage assuming that sectionalizing reclosers had been in place and uses the ICE calculator to monetize the new customer outage impact.

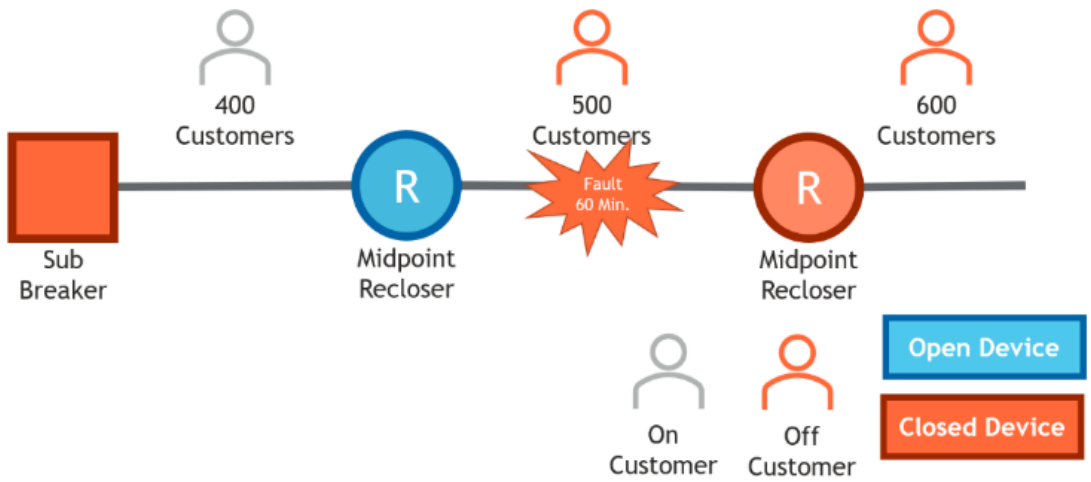
The model identifies outages on the mainline of the circuit (not on fused laterals or the secondary system) that are candidates for sectionalization improvement from adding reclosers. The model assumes that secondary and lateral outages do not benefit from adding a sectionalizing recloser. However, DTE uses a "fuse-saving" protection philosophy, and some lateral outages may in practice avoid a sustained interruption. The benefits of avoiding a sustained outage on laterals and the associated avoided truck roll are not quantified in the model.

Figure 4-23 and Figure 4-24 represent a simplified diagram of a circuit before and after investing in sectionalization. Without sectionalizing reclosers, a fault on the mainline of the circuit requires the breaker to operate, and all 1,500 customers downstream from the breaker experience an outage. In this example, crews take 60 minutes to identify the outage location, clear the outage, and restore power. 1,500 CI for 60 minutes results in 90,000 CMI for the event.

Figure 4-23: Simplified Outage Example without Sectionalizing Reclosers

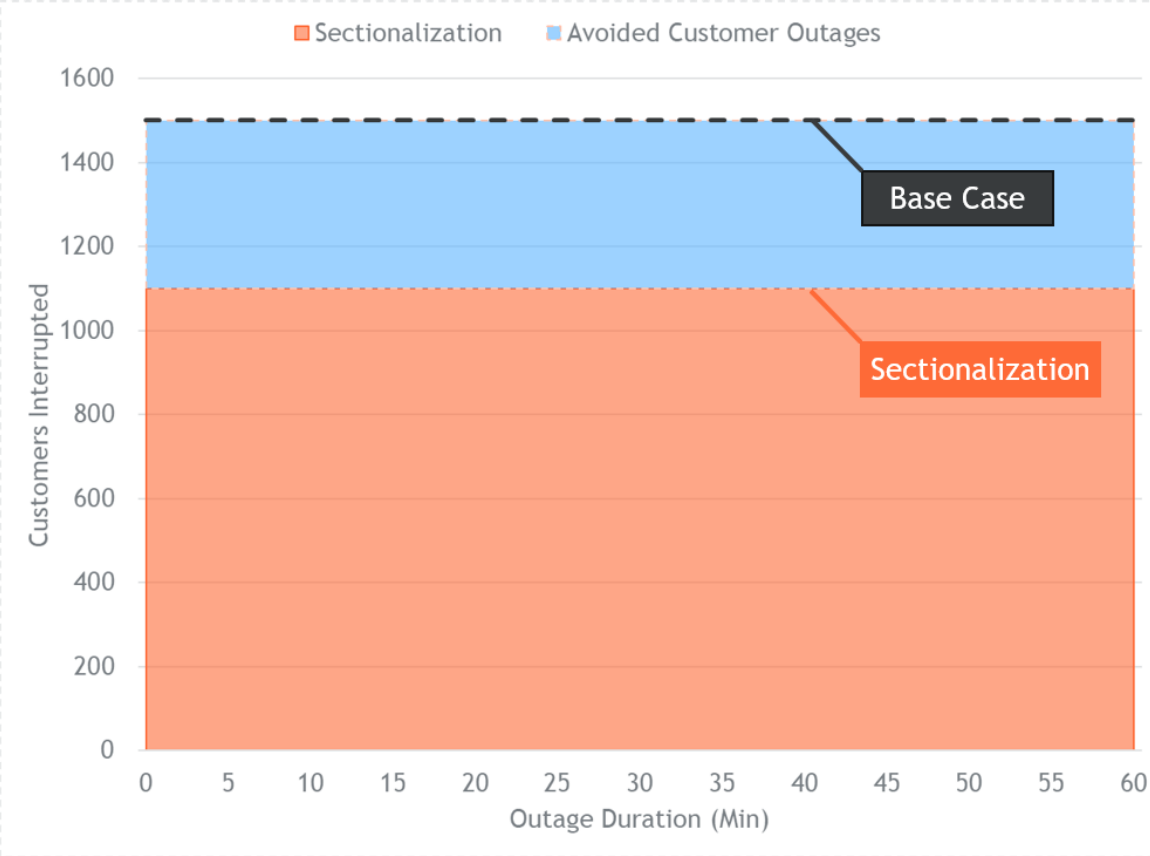
In the investment scenario for sectionalizing reclosers, shown below, a recloser isolates the fault. Due to the sectionalization afforded by the midpoint recloser, the 400 customers upstream of the recloser do not experience an outage. Only 1,100 customers are impacted in this scenario, with a resulting CMI of 66,000 (1,100 CI x 60 minutes). While there is likely improved response speed due to the known locations of the reclosing devices, the model conservatively assumes the job duration will remain the same as in the Status Quo scenario. Additionally, the model takes a weighted average of the CI to account for the fact that some faults will continue to occur upstream of any new reclosers and result in a breaker operation.

Figure 4-24: Simplified Outage Example with Investment in Sectionalizing Reclosers



The figure below shows the avoided CMI between the two scenarios. The blue section represents the avoided customer outages, which represents the customer benefit due to sectionalization. This avoided CMI is monetized using the ICE Calculator, which drives the customer benefits from investing in sectionalization.

Figure 4-25: Example of Sectionalization Benefit



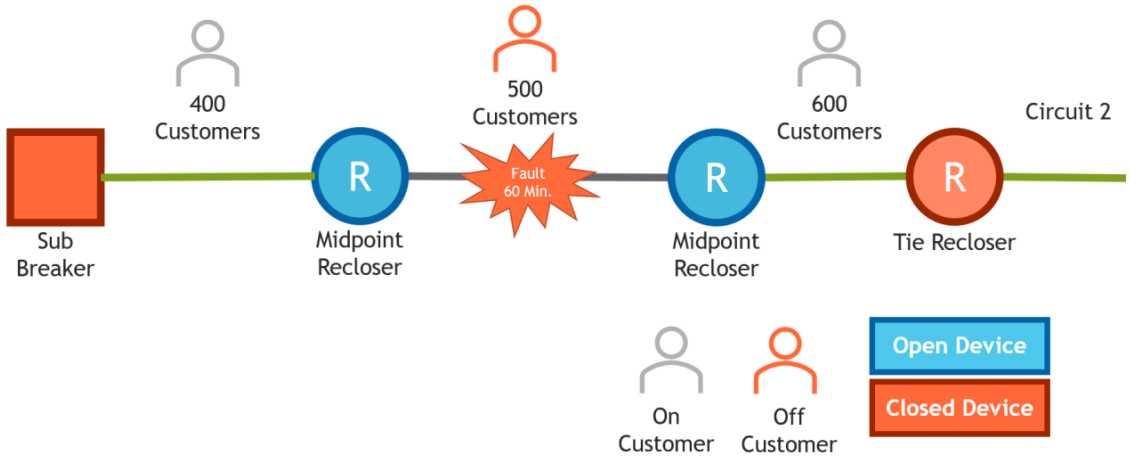
4.5.2.2 *Automate Existing and Build New Ties*

1898 & Co.'s Outage Mitigation Model assesses the benefits of investing in automated ties, necessary communication systems, and new tie construction to improve system flexibility and outage recovery. Based on the mapping of new devices to the OMS, 1898 & Co. recalculated the impact of mainline outages assuming the new customer count in each sectionalization pod and transferring customers not within the faulted pod to the adjacent circuit.

Figure 4-26 shows a simplified example of a circuit with reclosers added to support an Automate Ties scheme. This example represents the same 60-minute outage that occurs on a feeder with 1,500 customers downstream of the substation breaker. In this example, the fault is detected by the most upstream recloser, which operates and disconnects the 1,100 customers downstream of it. As a result of investment in

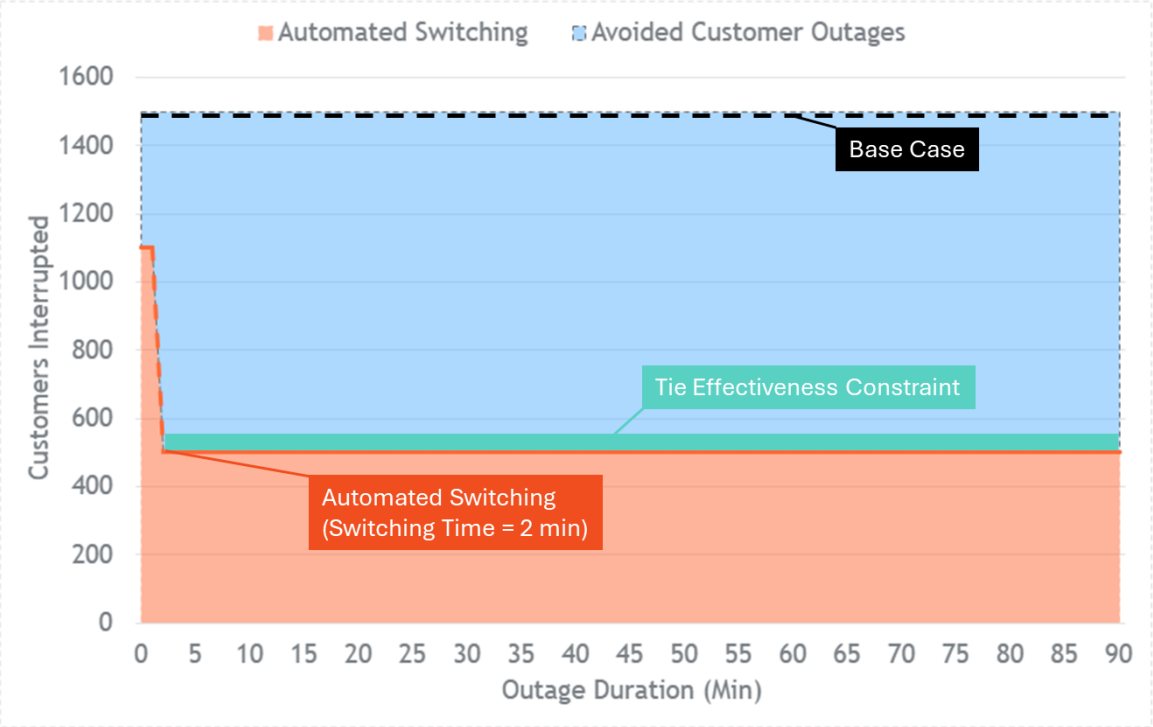
automated ties, the sectionalizing recloser downstream of the fault opens, and the tie recloser to an adjacent circuit closes. This allows the pod of customers downstream of the faulted pod to only experience a momentary outage and be restored within the automated switching time.

Figure 4-26: Simplified Diagram of Circuit with Automate Ties Scheme



It should be noted that the original number of customers impacted, and the duration of the entire outage is the same. The difference is in the ability to restore customers through automating ties rather than manual back feeding. Figure 4-27 below shows the avoided CMI resulting from investment in sectionalization and an automated tie recloser. The ability to automate ties substantially decreases the overall CMI in this example. The black dotted line represents the CMI without any Distribution Automation Program investment. The orange dotted line represents the CMI assuming distribution automation was fully effective.

Figure 4-27: Mainline Outage Profile with Sectionalization and Automated Tie



During major events, these investments may not operate if the supporting infrastructure (*e.g.*, tie lines and neighboring circuits or substations) is impacted. Additionally, during non-major event days, loading or thermal constraints may prevent the automated tie transfer from operating. The analysis applies MED and non-MED effectiveness to conservatively estimate the impact of these factors. The effectiveness of automating ties is shown below in Table 4-7. The impact of the tie effectiveness to the avoided CMI calculations is shown in the teal color shown in Figure 4-27.

Table 4-7: Constraints on Tie Effectiveness

Non-MED Automated Feeder Switching Effectiveness	MED Automated Feeder Switching Effectiveness
95%	80%

By integrating both automated ties and new tie construction into the analysis, the model provides a comprehensive assessment of how enhanced circuit connectivity can

improve system resilience and reliability. These investments create more opportunities for rerouting power, reducing outage duration, and ultimately lowering CMI across the system.

4.5.3 Normalization, Monetization, and Lifecycle Benefits Calculation

The mitigated outage improvement was normalized to a single year, averaging any significant year-to-year variations on outage types, outage causes, and circuits. The annualized value was then monetized using the ICE Calculator (detailed in Section 4.2) and customer profile for each outage. Applying escalation, a discount rate, and a 20-year expected useful life for the investments, the life-cycle benefit was calculated for each outage event and rolled up to the circuit level.

4.6 Qualitative Approach

The previous sections have outlined the methods used to quantify the benefits of specific investments within the Benefit-Cost Analysis framework. However, it is difficult to fully capture and monetize every factor that may influence an investment decision. As a result, qualitative considerations remain an important part of the overall evaluation. In general, these qualitative considerations fall into the following categories:

- Economic stability and attractiveness,
- Customer anxiety,
- Bolstering performance for lower performing areas (i.e. Customers Experiencing Multiple Interruptions) and disadvantaged communities.
- Safety and security,
- Capacity expansion to meet customer needs and improve operability and constructability including contingency (N-1)

Reliability and resilience investments support economic activity by helping businesses operate more consistently and making communities more attractive to residents and employers. These investments can also reduce customer anxiety and hardship associated with frequent or prolonged outages, particularly for customers who may

already face greater vulnerability during service interruptions. In addition, investments that improve service in lower-performing areas may provide equity-related benefits by helping address localized reliability concerns and improving outcomes for communities that have historically experienced a greater burden of outages. While these benefits are generally recognized as valid considerations in investment planning, they are inherently difficult to quantify directly and were therefore not monetized within 1898 & Co.'s modeling approach.

Safety and security considerations represent another important category of qualitative benefits. Many of the evaluated investments reduce safety risks to both the general public and DTE employees by lowering the likelihood of equipment failure, minimizing hazardous operating conditions, reducing exposure during restoration activities, or improving the ability to respond during major events. Certain investments may also provide broader security or system hardening benefits by improving the system's ability to withstand disruptive conditions. Although these safety- and security-related benefits are important, they are difficult to monetize in a manner that is sufficiently robust and consistent for direct inclusion in the BCR framework. Accordingly, 1898 & Co.'s quantitative evaluation does not directly include separate safety mitigation benefit streams.

Capacity expansion is an important factor in planning for future load and DER growth and enhancing system operability. Performing investments that expand capacity, such as voltage conversion projects and subtransmission redesign and rebuilds, enable the DTE system to reliably and efficiently serve customers now and into the future. These projects are an important part of meeting DTE planning criteria to deliver safe and reliable power. Additionally, investments that improve system capacity benefit the electric grid by reducing system complexity, which improves efficiency during construction work, and mitigating loading impact that can reduce asset life during peak load in the summer.

For this reason, the BCR should be interpreted as a decision-support metric rather than as the sole determinant of whether an investment is warranted. The BCR incorporates a substantial range of quantified benefit streams, but it does not capture

all relevant planning considerations. Therefore, when reviewing results, 1898 & Co. balances the quantified Benefit-Cost outcomes with important unquantified considerations, including safety risk mitigation, customer impacts, and broader strategic or equity-related objectives. As a result, an investment with a BCR ≥ 0.9 is appropriate where significant unquantified benefits are present and where those considerations materially support the investment rationale.

4.7 Model Integration and Calibration

1898 & Co.'s Integrated Resilience, Reliability, & Risk Investment Model incorporates the suite of benefit modeling approaches described above. These modeling approaches work together to create a data-driven and comprehensive BCA framework for evaluating a range of investment programs.

When evaluating multiple investments within the same area of the electric system, it is important to consider interactions among programs. The modeling framework evaluates investment programs in a defined sequence to reflect how multiple investments interact to avoid overstating benefits.

While each modeling approach is validated independently, the integrated suite of models is also calibrated to historical outage data to demonstrate that the framework produces results consistent with recent system reliability. This calibration shows that the Integrated Resilience, Reliability, & Risk Investment Model is grounded in reality and reliable for decision making.

4.7.1 Integrated Sequence of Programs

1898 & Co. conducted BCAs for multiple DTE investment programs. Because these programs affect the same infrastructure and outage mechanisms, the integrated modeling approach evaluates them to avoid attributing the same reliability benefits to multiple programs (i.e., to avoid double-counting benefits).

Electric systems experience a range of reliability challenges, and multiple investment programs can influence the same outage events. For example, a branch contacting an overhead line may cause a fault that results in a customer outage. Several investment programs can affect the likelihood or impact of this event. Vegetation Management

may reduce the likelihood of contact, PTMM may improve the condition and resilience of the infrastructure, and Distribution Automation may reduce the number of customers affected by automatically transferring load.

To account for these interactions, the modeling framework applies a defined sequence for incorporating investment programs. Under this approach, each program is evaluated relative to a baseline that reflects previously modeled investments. This approach allows the benefits attributed to each program to reflect only the incremental reliability improvements associated with that investment.

The modeling framework evaluates the benefits of programs by considering that there is a reduction in outages to account for vegetation management being performed before the BCR of PTMM or DA projects are calculated. The analysis identified outages likely to be avoided by vegetation management (wind- and tree-related) and applied reductions using the estimated tree-trimming effectiveness provided by DTE, for example, a 44% reduction in year 1 after tree trim and declining as years go on. This analysis considered circuits that have had recent investment in vegetation management and did not adjust those outages, as the CMI baseline reflects vegetation management investment.

The PTMM BCA is modeled using the Equipment Failure Mitigation and Resilience models and calibrated so that the Status Quo CMI reflects expected system performance under ongoing vegetation management activities. By utilizing this process, the PTMM evaluation does not attribute benefits already associated with Vegetation Management.

Similarly, the Distribution Automation BCA uses a Status Quo CMI baseline that incorporates expected reduction in benefits from DTE's vegetation management and the improvements analyzed in the PTMM program. As a result, the benefits estimated for Distribution Automation represent incremental improvements beyond those already captured by the preceding programs.

4.7.2 Integrated Model Calibration

The 1898 & Co. Resilience, Reliability, & Risk planning approach considers the broad range of stressors and failure types affecting DTE's overhead and underground systems. To capture this complexity, the analysis integrates the Equipment Failure Mitigation Modeling Approach described in Section 4.4 with the Resilience Modeling Approach described in Section 4.3. Together, these approaches provide a comprehensive view of system risk and expected reliability performance.

This integrated approach is particularly important because electric system reliability is driven by both day-to-day equipment-related outages and larger weather-related outage events. For PTMM, the Equipment Failure Mitigation Modeling Approach represents non-storm-related failures, including blue-sky equipment failures and other asset-driven outage mechanisms. Similarly for PTMM, the Resilience Modeling Approach captures weather-related outages, including major events that can cause significant customer interruption. By combining these approaches, the integrated model captures both routine reliability performance and the effects of storm-related events.

To calibrate the integrated model, 1898 & Co. compared modeled annual Customer Interruptions (CI) and Customer Minutes Interrupted (CMI) to historical outage performance derived from five years of DTE OMS data. The large quantity of historical outage data for distribution system overhead and underground assets allowed for a direct-comparison approach to distribution-system calibration. The limited availability of historical outage data for the subtransmission and substation systems required alternative calibration approaches. For instance, subtransmission-asset failure rates were calibrated to the failure rates for comparable distribution assets, while subtransmission outage durations were calibrated using duration frameworks derived from subtransmission architectures and the available outage data.

For calibration purposes, 1898 & Co. used the five-year average historical CI and CMI as the baseline for expected system performance. Modeled annual CI and CMI results were then compared to these historical values to evaluate how well the integrated framework reproduces observed reliability performance. This approach provides a

practical basis for assessing whether the model produces results consistent with recent system experience and supports the use of the framework in evaluating the incremental benefits of proposed investments.

To distinguish between weather-related and non-weather-related outages, 1898 & Co. separated outage events using an intersection of outage dates from OMS and historical NOAA weather event dates. This allowed the calibration to align non-storm equipment-related outage performance with the Equipment Failure Mitigation Modeling Approach and storm-period outage performance with the Resilience Modeling Approach. In addition, cause code information was used, where appropriate, to align specific model components with observed outage mechanisms.

The calibration process focused primarily on two categories of model inputs: (1) the likelihood that a given failure mechanism results in a customer outage, and (2) the duration of the resulting outage. These calibration levers materially influence modeled CI and CMI and were adjusted within reasonable bounds to better reflect observed system performance over the historical period.

This calibration provides confidence that the integrated modeling framework produces reasonable estimates of customer interruption frequency and duration and does not systematically overstate reliability benefits. As a result, the model provides an appropriate basis for evaluating the relative reliability, resilience, and risk reduction benefits of the investment programs analyzed in this report

5.0 Program Benefit-Cost Analysis Results

This section includes the Benefit-Cost Analysis (BCA) results for each of the programs evaluated by 1898 & Co. The programs analyzed are listed below:

1. Pole and Pole Top Maintenance & Modernization (PTMM)
2. Small Wire Replacement Program
3. URD Replacement Program
4. Cable Replacement Program
5. Breaker Replacement Program
6. Subtransmission SCADA
7. Distribution Automation (DA)
8. Communication Network
9. Subtransmission Redesign and Rebuild
10. 4.8 kV and 8.3 kV Conversion

Assets associated with the Subtransmission Redesign and Rebuild Program and the 4.8 kV and 8.3 kV Conversion Program were excluded from the analyses of the other evaluated programs. Each program section includes important background information, the approach to estimating investment activities and costs, quantified Benefit-Cost results, and qualitative considerations. Lastly, each section outlines how the data outlined in Section 2.0 and 3.0 and benefits modeling approach from Section 4.0 were utilized to estimate costs and benefits.

5.1 PTMM Program

This section includes the Benefit-Cost methodology and results for the PTMM program. The section contains background information on the program and the approach 1898 & Co. utilized to estimate the number and costs of poles and pole tops for replacement. The section also includes the Benefit-Cost results of the program and outlines additional factors for consideration. 1898 & Co. performed a comprehensive Benefit-Cost Analysis across the entire DTE system using the Resilience Event Simulation Model outlined in Section 4.3 and Equipment Failure Mitigation Model methodology outlined in Section 4.4 above. The PTMM program includes two sub-inspection

programs: Groundline Poles and Pole Tops. The Benefit-Cost Analysis was performed for each program separately. A detailed explanation of the inspection program and pole and pole-top reject rate analysis can be found in Section 2.6.

5.1.1 Background & Program Description

Pole inspections play a crucial role in maintaining the reliability and resilience of the power grid. Inspections help understand if utility poles can withstand environmental factors, including extreme weather conditions. This proactive approach enhances the overall resilience and reliability of the power grid, reducing the likelihood of service interruptions and improving the continuous delivery of reliable electricity to communities.

Inspections also contribute to the efficient management of utility assets by enabling early detection of issues, allowing utilities to plan and prioritize maintenance and replacement activities effectively. Utilities can reduce long-term costs and extend the lifespan of utility poles by allocating resources most efficiently. This proactive maintenance strategy supports the sustainable management of utility infrastructure. Regular inspections of utility poles are vital for identifying and addressing structural weaknesses, such as rot, insect damage, and mechanical failures. These weaknesses can compromise the stability of utility poles, posing significant risks of pole collapses. Such incidents can lead to power outages, property damage, and potential injuries. By conducting thorough inspections, utilities can mitigate these risks, ensuring the safety of both the infrastructure and the public.

DTE has enhanced its groundline and pole top inspections to proactively replace aging and defective assets on its system over the past several years. DTE has started planning for 10-year and 5-year cycles for groundline and pole top inspections, respectively. This PTMM Benefit-Cost Analysis has been enhanced to evaluate benefits at the protection zone level for distribution primary, with results then aggregated to the substation level, and at the circuit level for subtransmission, consistent with DTE's execution approach for the program. This refined approach improves the linkage between individual assets, their failure mechanisms, and the customers impacted, while still supporting substation-level planning and decision-making.

While the BCA considered two separate PTMM programs, one groundline and one pole top, Section 5.1.2 begins by describing an overarching groundline-and-pole-top PTMM approach before detailing the individual inspection programs. These individual programs have separate evaluations to reduce the risk of double-counting benefits with the different cycle lengths.

5.1.2 Estimating Investment Activities and Cost

This section outlines the systematic approach employed by 1898 & Co. to identify investment activities for the programs and estimate their expected costs. It begins with an overarching approach to evaluating a consolidated groundline-and-pole-top PTMM program before diverging to discuss the individual programs.

The core element of an overarching PTMM program is the inspection of the pole groundline and top. To model that inspection, the approach treated the overarching inspection as a sequence of decisions and tasks, beginning with the groundline inspection and concluding, as needed, with the pole top inspection.

1. Groundline Inspection
    a. If the pole was less than 10 years old, then no groundline inspection (or pole top inspection) was needed, and no cost was incurred.
    b. If the pole was at least 10 years old, then it received a visual inspection, with an associated cost.
    c. If the pole was at least 20 years old, then it received a second, physical inspection with an additional associated cost.
    d. If the pole failed a visual or a physical groundline inspection, then the inspection results designated the pole for either replacement or for reinforcement, i.e., trussing. Each of the two alternatives had an additional cost.
2. Pole Top Inspection
    a. If the pole failed inspection and was designated for replacement, then the pole top was replaced with the pole. There was no need for pole top inspection, but there was a cost associated with replacing the pole top.

b. If the pole was at least 10 years old and was not designated for replacement, then the pole top received a visual inspection, the cost for which was included in the pole inspection cost.
c. If the pole top failed inspection, then the pole top was replaced with an associated replacement cost.

The following sub-sections provide the approach utilized to identify investment activities and estimate their cost. The groundline-only and pole top-only inspection programs had overlapping elements, so the sum of the groundline-only and pole top-only inspection programs will exceed the cost for an overarching inspection program.

5.1.2.1 Program 1: Groundline Pole Inspection Program

- **Investment Activity Identification:** 1898 & Co. utilized the GIS data to identify the number of poles on each circuit. These circuits included subtransmission and primary distribution. The expected number of poles to be replaced was based on the age of the pole and the expected reject rate (see Section 2.6). 1898 & Co. utilized the age data from the GIS to estimate pole age (see Section 2.5). Using the historical rejection rates, both non-restorable and restorable, from previous groundline inspections (see Section 2.6), poles were given a probability of failure due to inspection. Based on these rejection rates and specific poles and their ages on each circuit, 1898 & Co. estimated the number of poles expected to fail inspection on each circuit.
- **Investment Activity Cost Estimation:** The cost to inspect a circuit was based on the number of poles on the circuit and on the average inspection cost per circuit. DTE provided the unit cost for inspection. 1898 & Co. assigned a visual or physical inspection cost for each pole, depending on DTE's inspection standards. These costs were then aggregated to the substation level to determine the distribution PTMM cost and to the circuit level to determine the subtransmission PTMM cost. DTE also provided unit costs to replace poles and to restore poles. 1898 & Co estimated the pole inspection costs by circuit by multiplying each pole's probability of failure (POF) for each rejection type, reject requiring replacement or restoration reject, by these unit costs. The

sum of all the probability-weighted rejection rates and costs for all the poles on the circuit provided the total circuit costs.

5.1.2.2 Program 2: Pole Top Maintenance Program

- **Investment Activity Identification:** Investment activities for this program follow the same process as the Groundline Pole Inspection Program above. The differences are that this program only looks at pole tops and uses a different set of rejection rates derived from pole top-specific historical inspection data.
- **Investment Activity Cost Estimation:** Like the activity identification above, the cost estimation for the Pole Top Maintenance Program follows the same process as the Groundline Pole Inspection Program. The only difference is that pole tops will only have a visual inspection cost and no physical inspection cost.

5.1.3 Quantitative Benefit-Cost Results

The following four subsections include the Benefit-Cost results for the Groundline and Pole Top Inspection Programs. 1898 & Co. evaluated this program and sub-programs comprehensively across the entire DTE distribution and subtransmission overhead systems, mapping poles to the upstream protection device to provide a granular linkage of the customers impacted if the pole were to fail. The evaluation organized the benefits and costs of this program at the substation level for distribution and circuit level for subtransmission circuits in alignment with DTE's execution approach for the program and sub-programs. This section includes the quantified benefit results from the analytics models described in Section 4.3 and 4.4. These results assume that:

1) Vegetation management has occurred on all circuits.
2) No Distribution Automation investment activities are occurring on the DTE system.

For ease of representing this level of information, the quantified benefit results are shown on a percentile ranking basis. The ranking is based on the Resilience, Reliability, & Risk BCR.

5.1.3.1 Distribution Groundline Pole Inspection Program

Figure 5-1 includes the expected avoided customer outage benefits for the Distribution PTMM Groundline Program. The figure illustrates the absolute benefit in CMI and the percentage improvement. The figure also includes which substation percentiles have a quantified BCR ≥ 0.9. As the figure shows, approximately 83% of the substation percentile bins shown have quantified benefits with a BCR ≥ 0.9. For these investment activities, the evaluation shows an average expected improvement in CMI of approximately 48%, ranging from 44% to 61%, in the percentile ranking view.

Figure 5-1: Distribution PTMM Groundline Inspection Avoided Customer Outage Benefit

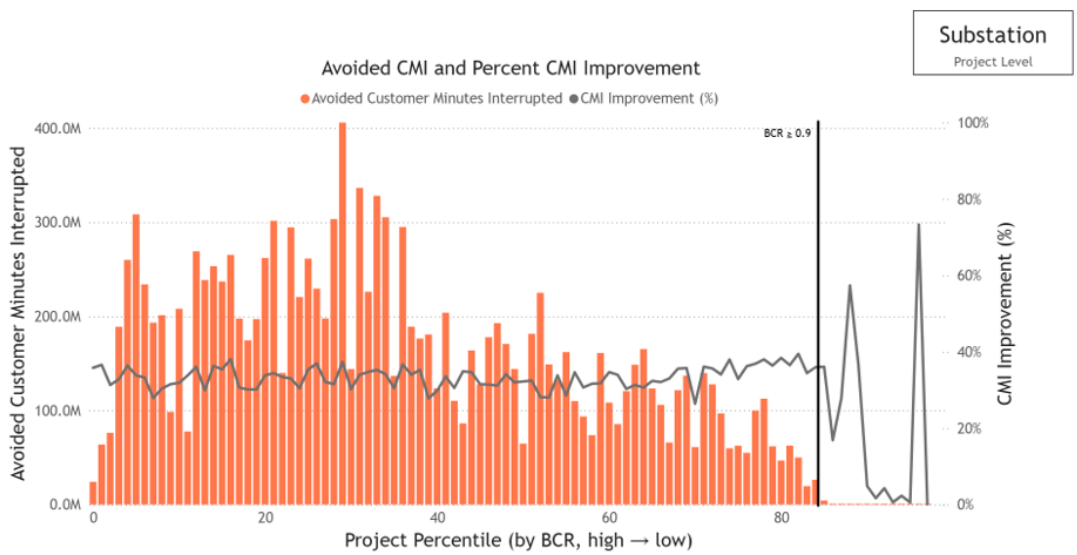


Figure 5-2 uses the CMI benefits shown in Figure 5-1 and applies the ICE Calculator (see Section 4.2) to show monetized CMI, along with the avoided restoration costs for projects at the substation level. It is important to note that the application of the ICE Calculator incorporates the various customer types into the evaluation. This figure shows the total monetized resilience and risk benefits of this program. As the figure shows, most of the quantified benefits are from avoided customer outages. The figure also includes the expected improvement in monetized customer outages and

restoration costs. The substation percentiles with a BCR ≥ 0.9 show an improvement in monetized customer outages of 30% on average, ranging from 23% to 35%, and 46% on average for restoration costs, ranging from 40% to 54%, in the percentile ranking view.

Figure 5-2: Distribution PTMM Groundline Inspection Program Benefits Summary

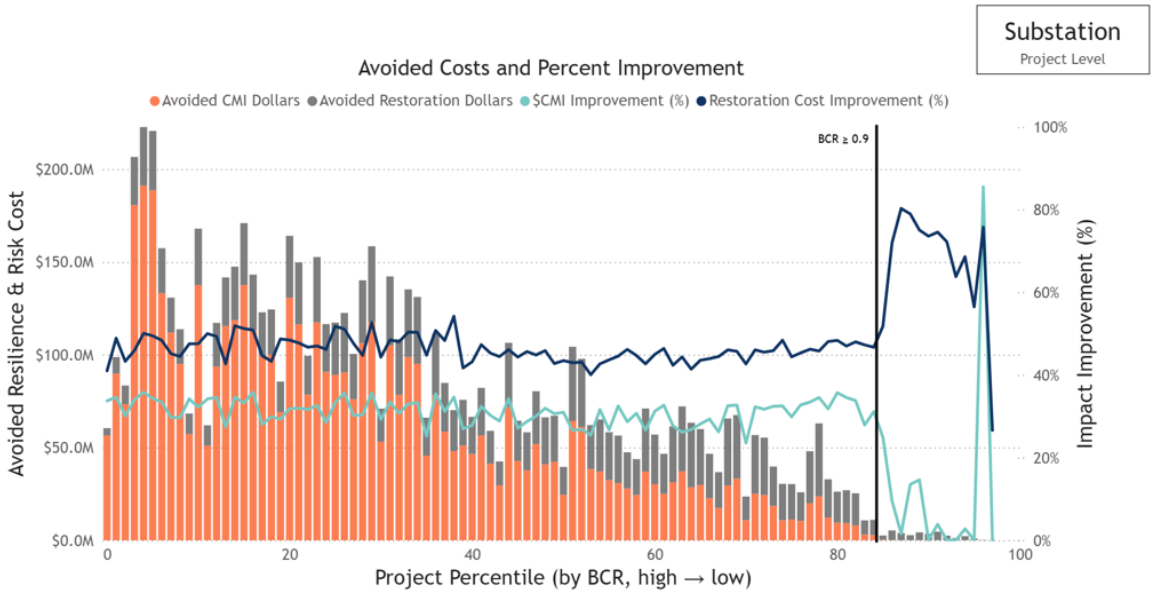
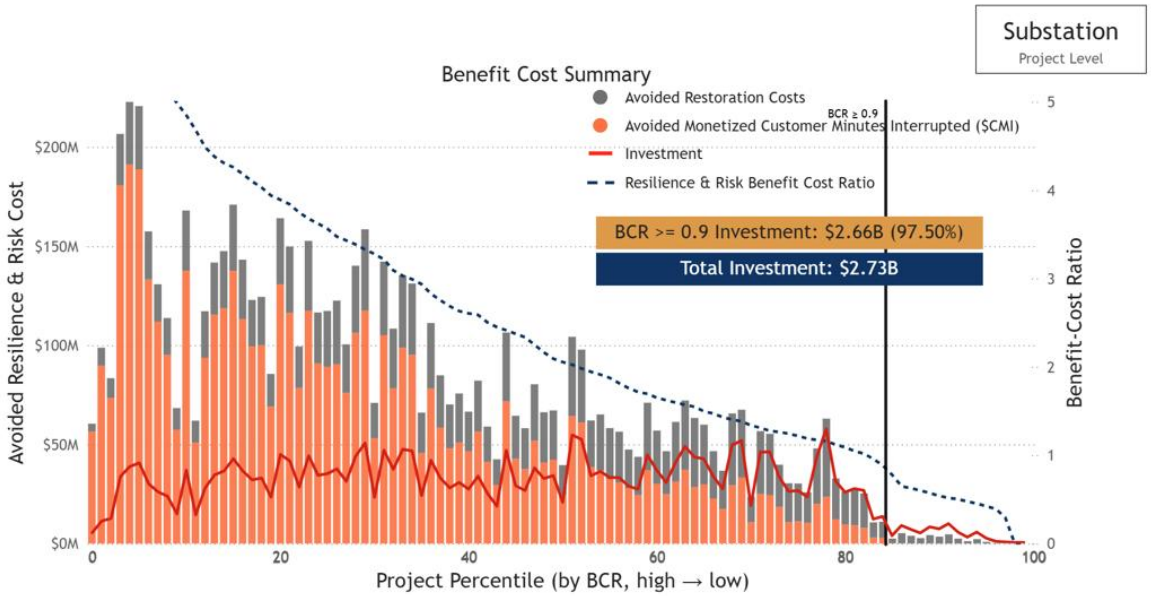


Figure 5-3 takes the benefit results from Figure 5-2 and layers in the expected resiliency investment for each substation to show the Resilience, Reliability, & Risk BCR. Figure 5-3 shows that if this program were applied to the entire DTE distribution system, the overall investment level would be approximately $2.73 billion. The weighted BCR for deploying this program across the entire system is 2.72. The figure shows that approximately $2.66 billion, or 97.5% of the total investment, has a BCR ≥ 0.9. The weighted BCR for deploying this program only on circuits where the BCR ≥ 0.9 is 2.77.

Figure 5-3: Distribution PTMM Groundline Inspection Program BCR Summary



5.1.3.2 Distribution Pole Top Maintenance Program

Figure 5-4 includes the expected avoided customer outage benefits for the distribution PTMM pole-top inspection program. The figure consists of the absolute benefit in CMI and the percentage improvement. The figure also includes which substation percentiles have quantified benefits. As the figure shows, approximately 85% of the substation percentiles have quantified benefits with a BCR ≥ 0.9. For these investment activities, the evaluation shows an expected improvement in CMI of approximately 21%, ranging from 15% to 30%, in the percentile ranking view.

Figure 5-4: Distribution PTMM Pole Top Inspection Avoided Customer Outage Benefit

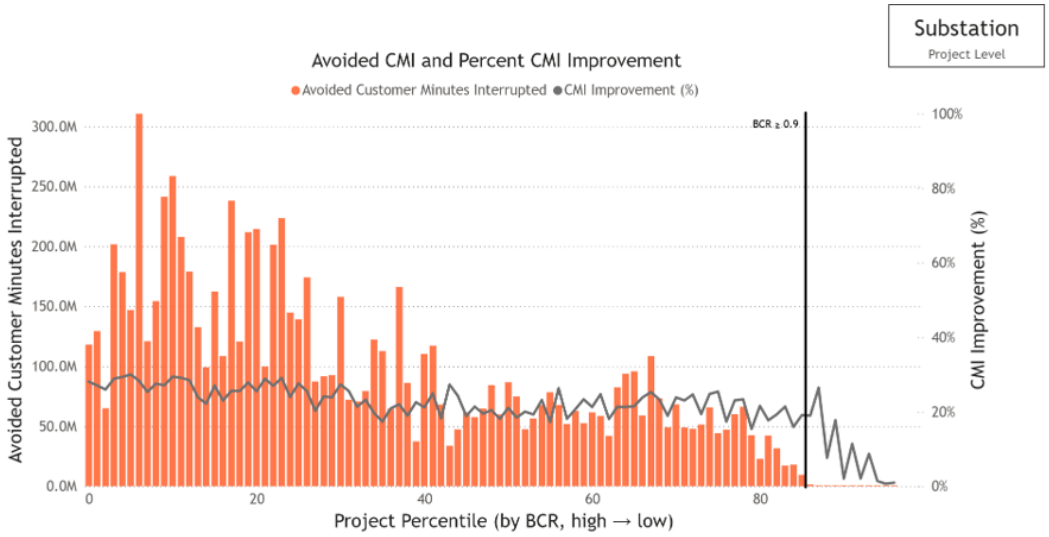


Figure 5-5 takes the CMI benefits from Figure 5-4 and applies the ICE Calculator (see Section 4.2) to monetize the outages and add the avoided restoration costs for each substation. It is important to note that the application of the ICE Calculator incorporates the various customer types into the evaluation. This figure shows the total monetized resilience and risk benefits of this program. Figure 5-5 illustrates that most of the quantified benefits are from avoided customer outages. The figure also includes the expected improvement in monetized customer outages and restoration costs. The substations with a BCR ≥ 0.9 show an improvement in monetized customer outages of 21% on average, ranging from 13% to 30%, and 24% for restoration costs, ranging from 18% to 27%, in the percentile ranking view.

Figure 5-5: Distribution PTMM Pole Top Program Benefits Summary

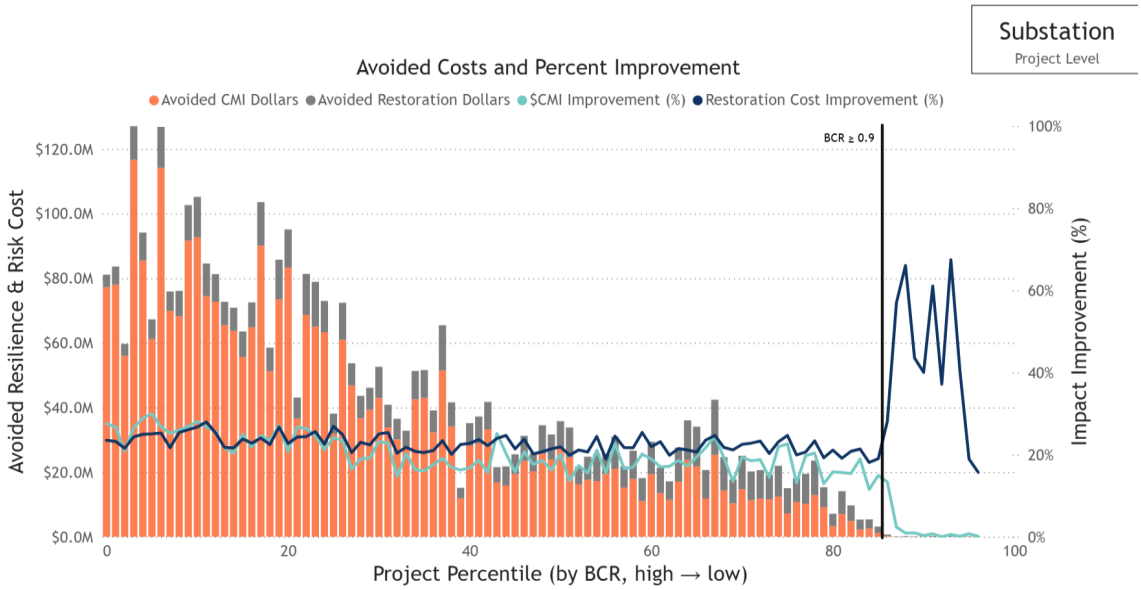
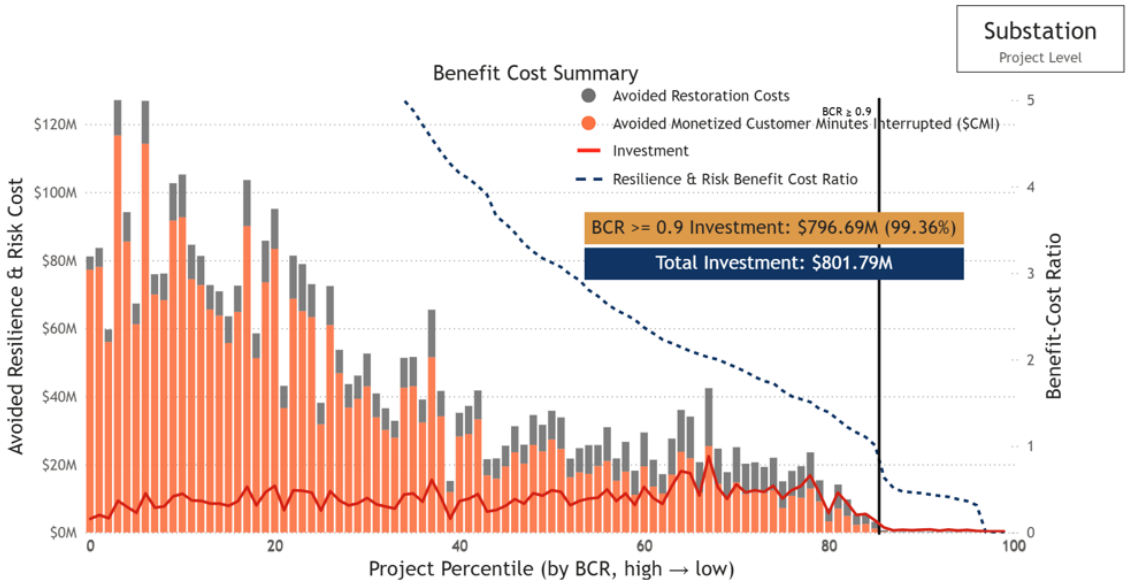


Figure 5-6 takes the benefit results from Figure 5-5 and layers in the expected investment for each substation to show the Resilience, Reliability, & Risk BCR. As the figure shows, if this program were applied to the entire DTE distribution system, the overall investment level would be approximately $801.79 million. The weighted BCR for deploying this program is 4.78. The figure shows that approximately $796.69 million, or 99.36% of the total investment, has a BCR ≥ 0.9. The weighted BCR for deploying this program only on circuits where the BCR ≥ 0.9 is 4.81.

Figure 5-6: Distribution PTMM Pole Top Inspection Program BCR Summary



5.1.3.3 Subtransmission Groundline Pole Inspection Program

Figure 5-7 includes the expected avoided customer outage benefits for the subtransmission PTMM groundline program. The figure illustrates the absolute benefit in CMI and the percentage improvement. The figure also includes which circuit percentiles have quantified benefits with a BCR ≥ 0.9. As the figure shows, approximately 76% of the circuit percentiles shown have a BCR ≥ 0.9. For these circuit percentiles, the evaluation shows an average expected improvement in CMI of approximately 63%, ranging from 21% to 81%, in the percentile ranking view.

Figure 5-7: Subtransmission PTMM Groundline Inspection Avoided Customer Outage Benefit

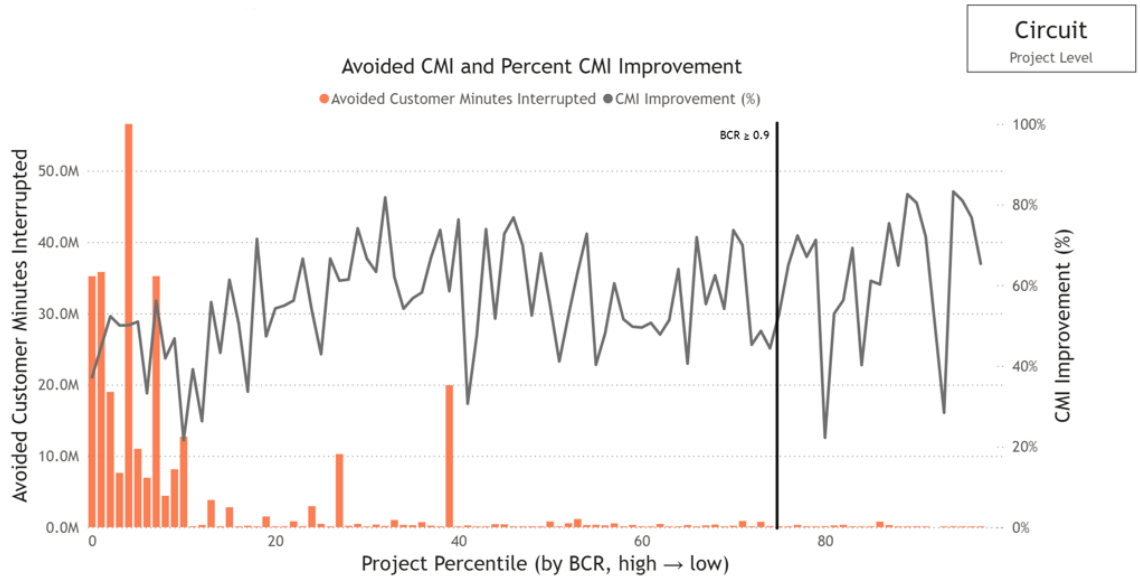


Figure 5-8 takes the CMI benefits from Figure 5-7 and applies the ICE Calculator (see Section 4.2) to monetize the outages and adds the avoided restoration costs for each circuit. It is important to note that the application of the ICE Calculator incorporates the various customer types into the evaluation. This figure shows the total monetized resilience and risk benefits of this program. The figure also includes the expected improvement in monetized customer outages and restoration costs. The circuits with a BCR ≥ 0.9 show an improvement in monetized customer outages of 25% on average, ranging from 7% to 87%, and 51% on average for restoration costs, ranging from 33% to 63%, in the percentile ranking view.

Figure 5-8: Subtransmission PTMM Groundline Inspection Program Benefits Summary

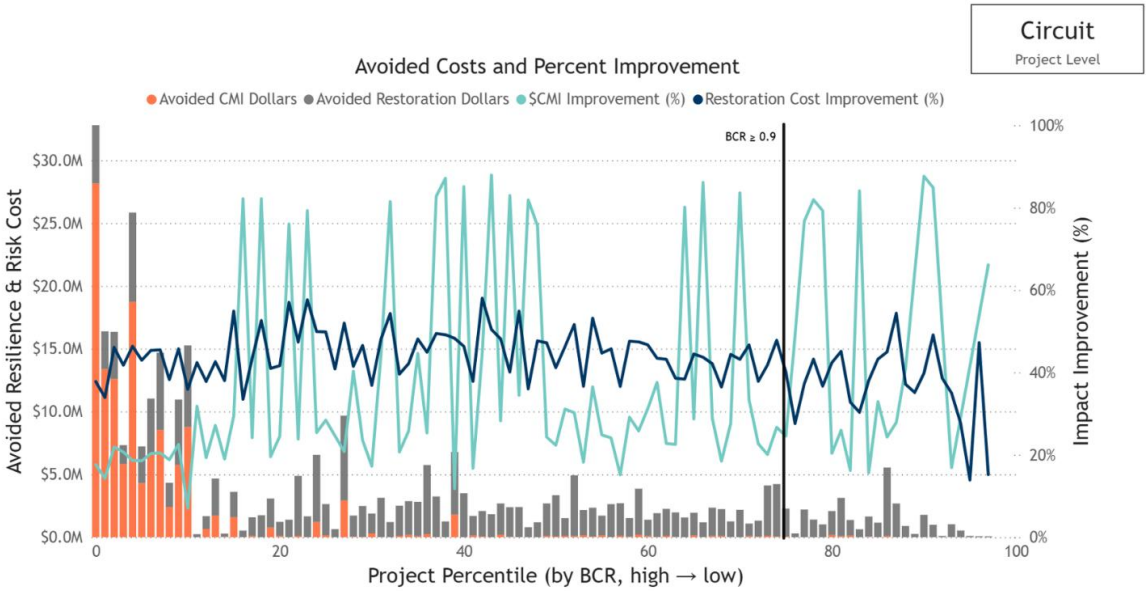
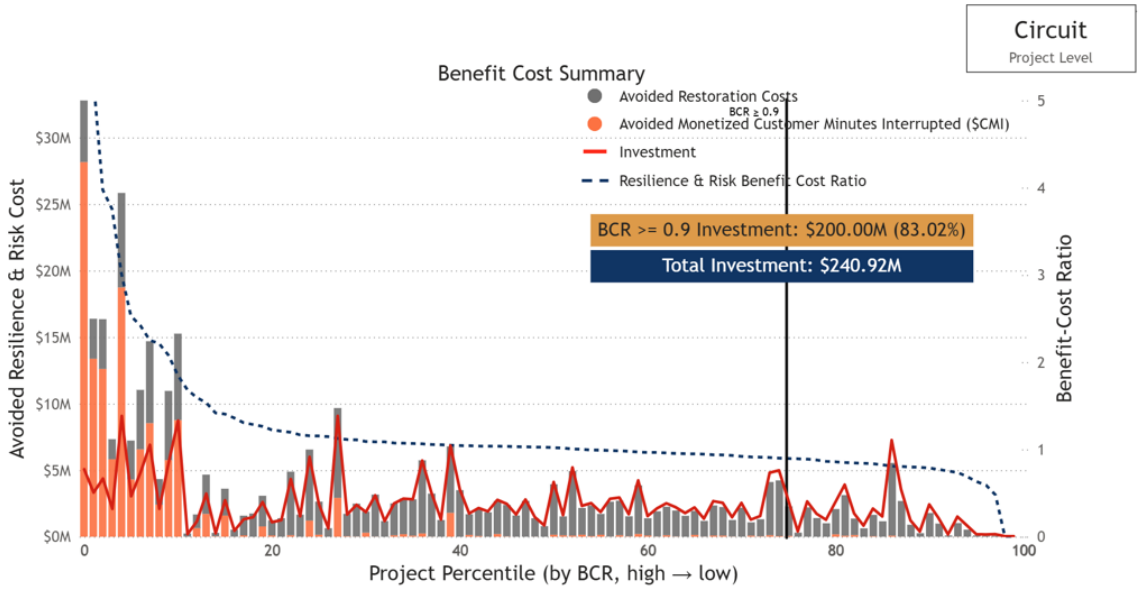


Figure 5-9 takes the benefit results from Figure 5-8 and layers in the expected resiliency investment for each circuit to show the Resilience, Reliability, & Risk BCR. Figure 5-9 depicts that if this program were applied to the entire DTE system, the overall investment level would be approximately $240.92 million. The weighted BCR for deploying this program across the entire system is 1.47. The figure shows that approximately $200 million, or 83% of the total investment level, has a BCR ≥ 0.9. The weighted BCR for deploying this program is only on circuits where the BCR ≥ 0.9 is 1.6.

Figure 5-9: Subtransmission PTMM Groundline Inspection Program BCR Summary



5.1.3.4 Subtransmission Pole Top Maintenance Program

Figure 5-10 includes the expected avoided customer outage benefits for the subtransmission PTMM pole-top inspection program. The figure consists of the absolute benefit in CMI and the percentage improvement. As the figure shows, approximately 49% of the circuit percentiles have quantified BCR ≥ 0.9. For these investment activities, the evaluation shows an expected improvement in CMI of approximately 34%, ranging from 4% to 86%, in the percentile ranking view.

Figure 5-10: Subtransmission PTMM Pole Top Inspection Avoided Customer Outage Benefit

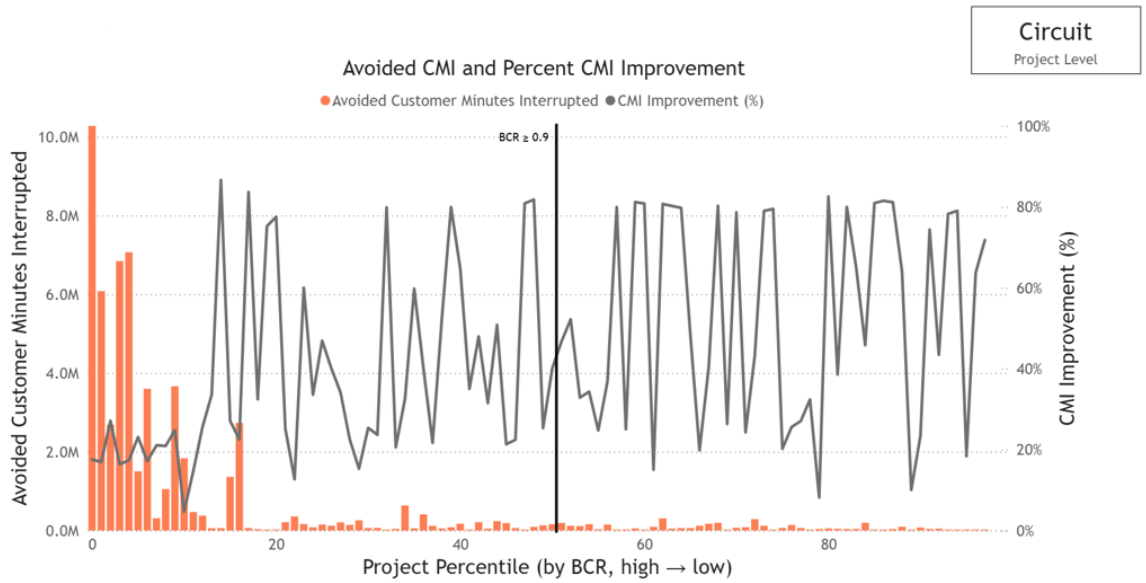


Figure 5-11 takes the CMI benefits from Figure 5-10 and applies the ICE Calculator (see Section 4.2) to monetize the outages and add the avoided restoration costs for each circuit. It is important to note that the application of the ICE Calculator incorporates the various customer types into the evaluation. This figure shows the total monetized resilience and risk benefits of this program. Figure 5-11 illustrates that most of the quantified benefits are from avoided customer outages. The figure also includes the expected improvement in monetized customer outages and restoration costs. The circuits with a BCR ≥ 0.9 show an improvement in monetized customer outages of 28% on average, ranging from 4% to 91%, and 13% for restoration costs, ranging from 7% to 20%, in the percentile ranking view.

Figure 5-11: Subtransmission PTMM Pole Top Program Benefits Summary

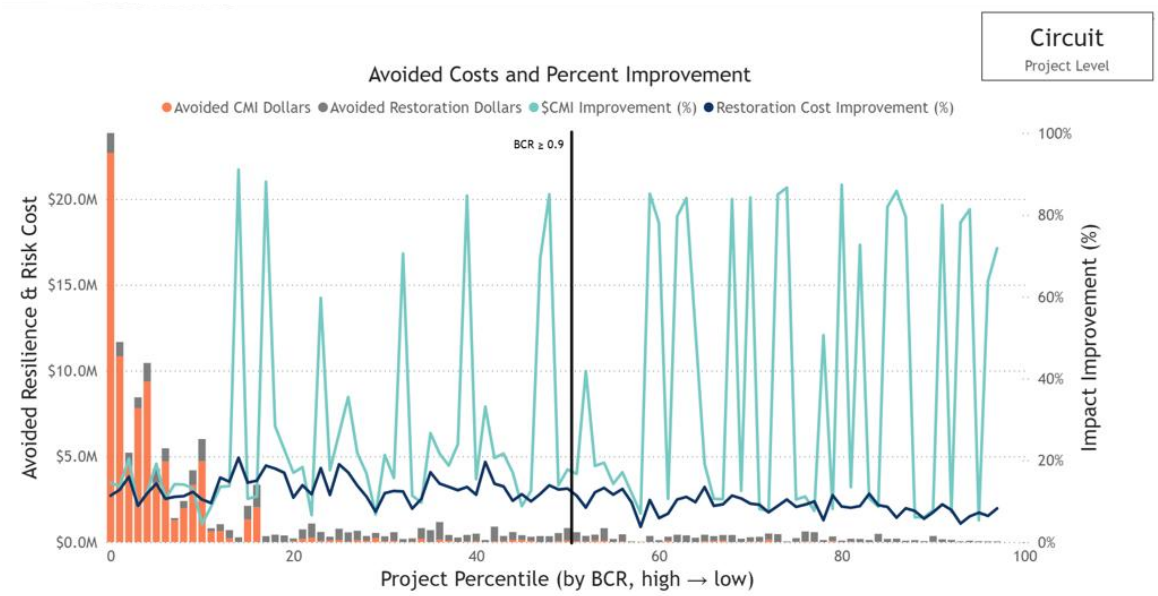
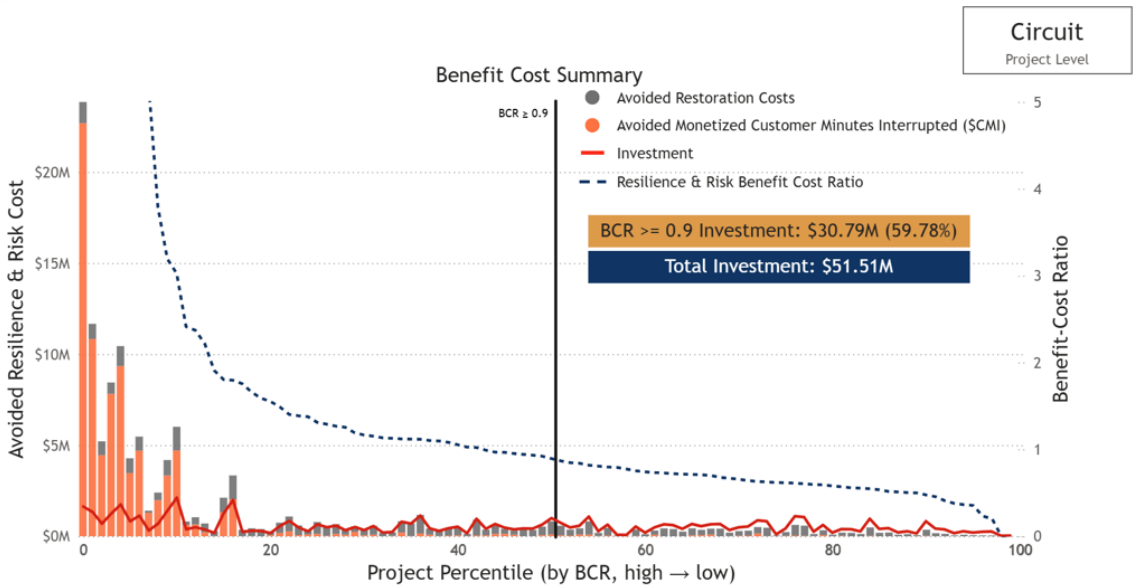


Figure 5-12 takes the benefit results from Figure 5-11 and layers in the expected investment for each circuit to show the Resilience, Reliability, & Risk BCR. As the figure shows, if this program were applied to the entire DTE distribution system, the overall investment level would be approximately $51.51 million. The weighted BCR for deploying this program is 2.37. The figure shows that approximately $30.79 million, or 59.78% of the total investment, has a BCR ≥ 0.9. The weighted BCR for deploying this program only on circuits where the BCR ≥ 0.9 is 3.52.

Figure 5-12: Subtransmission PTMM Pole Top Inspection Program BCR Summary



5.1.4 Qualitative Additional Benefits of the Program

The previous sections have outlined the results from quantifying the benefits of specific investments. As discussed, it is difficult to fully capture and quantify all the factors that go into every investment decision. For the PTMM program, a key benefit stream not included in the quantified Benefit-Cost Analysis is mitigating safety risks. Pole and pole-top failures expose the public to safety hazards. Additionally, there are benefits to DTE crews in not having to replace failed equipment reactively. One of the failure types included in the quantitative evaluation was equipment failures during weather events. In this scenario, crews replace failed pole infrastructure following major events. This can be in extreme cold or wet conditions, with infrastructure replacements occurring at all hours of the day, including in the dark. This program would mitigate the failures during these events and minimize the safety risk exposure to DTE crews. Given the safety risk exposure, inspection-based programs like PTMM are appropriate for the sole purpose of mitigating safety risks. As such, while the PTMM investment has quantified benefits for customers, the qualitative safety risk mitigation benefits further justify this investment.

5.2 Small Wire Replacement Program

This section includes the Benefit-Cost methodology and results for the Small Wire Replacement Program. The section provides background information on the program, describes the approach 1898 & Co. utilized to identify investment activities and estimate project costs, and summarizes the resulting Benefit-Cost findings. The section also outlines additional factors for consideration when interpreting the results.

1898 & Co. performed the Benefit-Cost Analysis using the Resilience Event Simulation Model outlined in Section 4.3 and the Equipment Failure Mitigation Model methodology outlined in Section 4.4. Consistent with the broader modeling framework, benefits were evaluated at the protection zone level and then aggregated to the circuit level for planning and decision-making purposes.

5.2.1 Background & Program Description

The Small Wire Replacement Program is intended to improve the resilience and reliability of DTE's distribution primary overhead system through targeted rebuilds within a project's protection zone. The program focuses on replacing distribution primary overhead conductor and associated assets in areas where existing conductor characteristics indicate a higher likelihood of failure, reduced performance under stress, or the need for modernization. By proactively rebuilding these sections, DTE can reduce future outage risk, improve system performance under both blue-sky and weather event conditions, and support more effective long-term asset management.

Small wire is generally more vulnerable to failure under loading and vegetation interaction than larger conductor. As a result, targeted replacement of small wire can improve the ability of the system to withstand stressors and reduce the likelihood of customer outages. The program also provides an opportunity to replace other associated assets within the protection zone, such as pole tops, older poles, and applicable line transformers, where those assets are included as part of the rebuild scope. This allows the program to address asset conditions in a more integrated manner and better align investment activities with the expected configuration of the rebuilt line segment.

Under this evaluation, projects were defined at the protection zone level and aggregated to the circuit level. Each project reflects a targeted rebuild of distribution primary overhead assets within the protection zone based on the program inclusion criteria. Any section containing qualifying small wire was identified for inclusion in the program. This approach supports a more granular evaluation of investment needs and improves the relationship between the assets included in the rebuild, the failures avoided, and the customers impacted.

5.2.2 Estimating Investment Activities and Cost

This section outlines the systematic approach used by 1898 & Co. to identify investment activities for the Small Wire Replacement Program and estimate their expected costs. The analysis begins at the protection zone level, where each investment activity is evaluated based on the assets located within the zone and the applicable program inclusion criteria. If any section within a protection zone contains qualifying small wire, the entire protection zone is identified for inclusion in the Small Wire Replacement Program. The associated costs are then estimated at the protection zone level and aggregated at the circuit level for comparison and planning purposes.

The core element of the program is the targeted rebuild of distribution primary overhead assets within the protection zone. To identify candidate projects, the modeling approach first evaluates conductor sections within each protection zone against the program's small wire criteria. The criteria includes the following wire sizes:

1) 1/0 aluminum single-phase conductor
2) 2 or 6 copper single-phase conductor
3) 1/0 aluminum two-phase 4.8 kV/8.3 kV conductor
4) 2 or 6 copper two-phase 4.8 kV/8.3 kV conductor

If any conductor section within the protection zone meets one or more of these criteria, the protection zone is classified as a small wire project and the rebuild scope is developed for the entire protection zone.

After a protection zone is identified for inclusion, the model determines the assets to be included in the rebuild across that full protection zone. All pole top components within the protection zone are included. Poles are included when their age exceeds 40 years. Line transformers with a voltage below 13.2kV are included for replacement with dual transformers, but this does not imply conversion. As these protection zones have already been selected to contain small wire, all conductor within them is included. Together, these assumptions define the investment activities and project scope used to estimate project cost for each protection zone.

Once the included assets are identified, project costs are estimated using the applicable unit cost assumptions for each asset class. These costs are then combined at the protection zone level to form the total project cost for each candidate investment. The resulting project definitions and costs serve as inputs to the modeling framework used to estimate the resilience, reliability, and risk reduction benefits of the program. Evaluating the program at the protection zone level improves the linkage between the assets included in the rebuild, the failures avoided, and the customers impacted, while aggregation to the circuit level maintains consistency with broader planning and portfolio evaluation.

5.2.3 Quantitative Benefit-Cost Results

1898 & Co. evaluated this program comprehensively across DTE's distribution overhead system. The evaluation organized the benefits and costs of this program at the circuit level in alignment with DTE's execution approach for the program. This section includes the quantified benefit results from the analytics models described in Section 4.3 and Section 4.4. These results assume that:

1) Benefits from vegetation management are accounted for, and
2) Distribution Automation investment activities have not occurred on the DTE system.

The quantified benefits results for this program were aggregated to the circuit level in alignment with the execution approach intended by DTE for this program. For ease of representing this level of information, the quantified benefit results are shown on a

percentile ranking basis. The ranking is based on the Resilience, Reliability, & Risk BCR.

Figure 5-13 includes the expected avoided customer outage benefits for the Small Wire Replacement Program. The figure consists of the absolute benefit in CMI and the percentage improvement. As the figure shows, approximately 35% of the circuits shown in the percentiles have quantified benefits with a BCR ≥ 0.9. For these circuits, the evaluation shows an average expected improvement in CMI of approximately 83%, ranging from 81% to 86%, in the percentile ranking view.

Figure 5-13: Small Wire Replacement Program Avoided Customer Outage Benefit

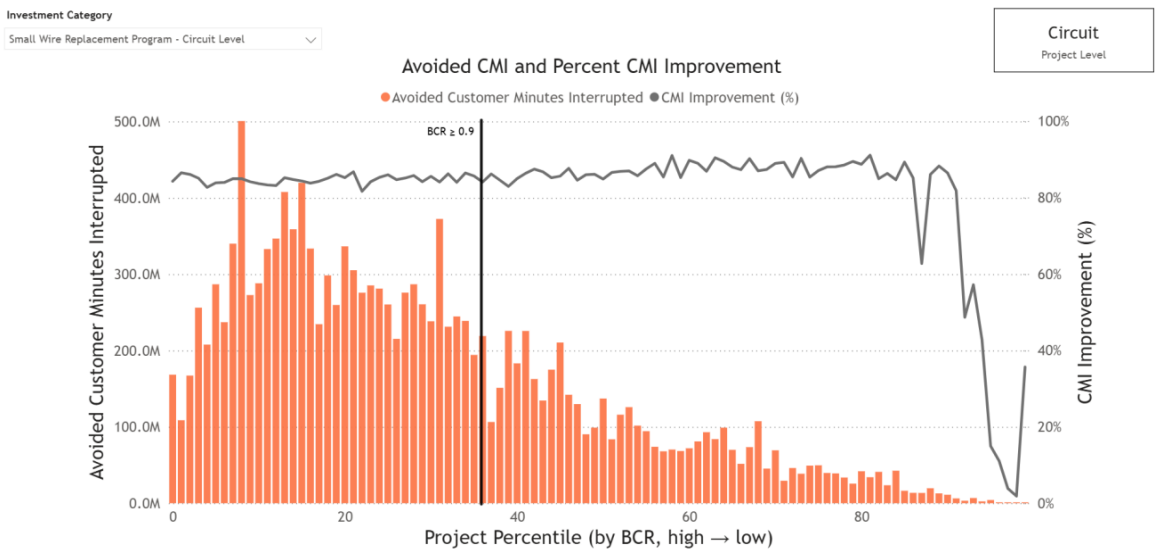


Figure 5-14 takes the CMI benefits from Figure 5-13 and applies the ICE Calculator (see Section 4.2) to monetize the outages and adds the avoided restoration costs for each circuit. It is important to note that the application of the ICE Calculator incorporates the various customer types into the evaluation. This figure shows the total monetized resilience and risk benefits of this program. The figure also includes the expected improvement in monetized customer outages and restoration costs. The circuits with a BCR ≥ 0.9 show an improvement in monetized customer outages of 84% on average, ranging from 82% to 86%, and 85% on average for restoration costs, ranging from 82% to 87%, in the percentile ranking view.

Figure 5-14: Small Wire Replacement Program Benefits Summary

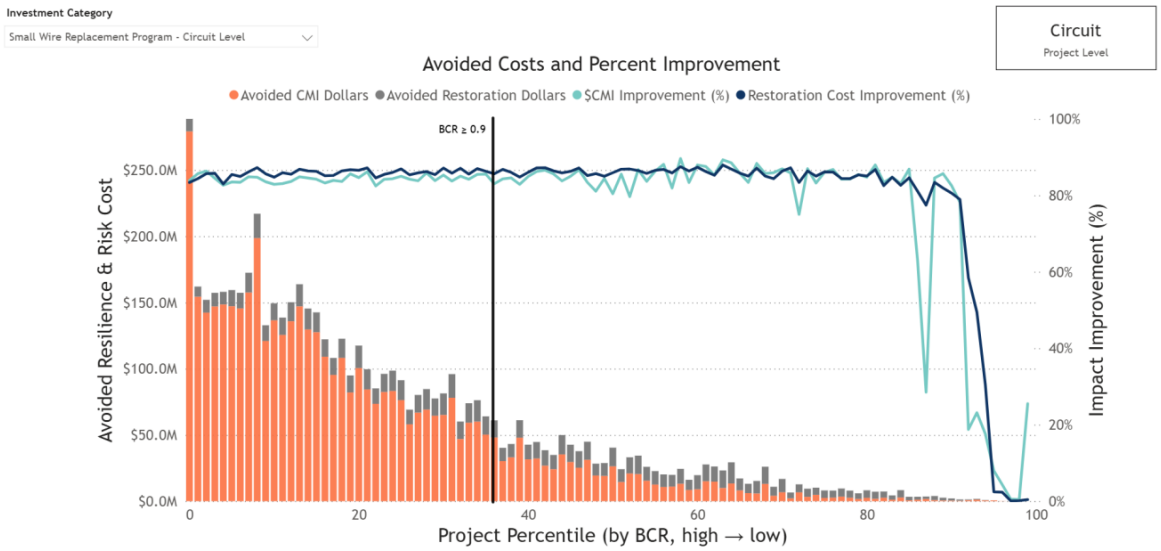
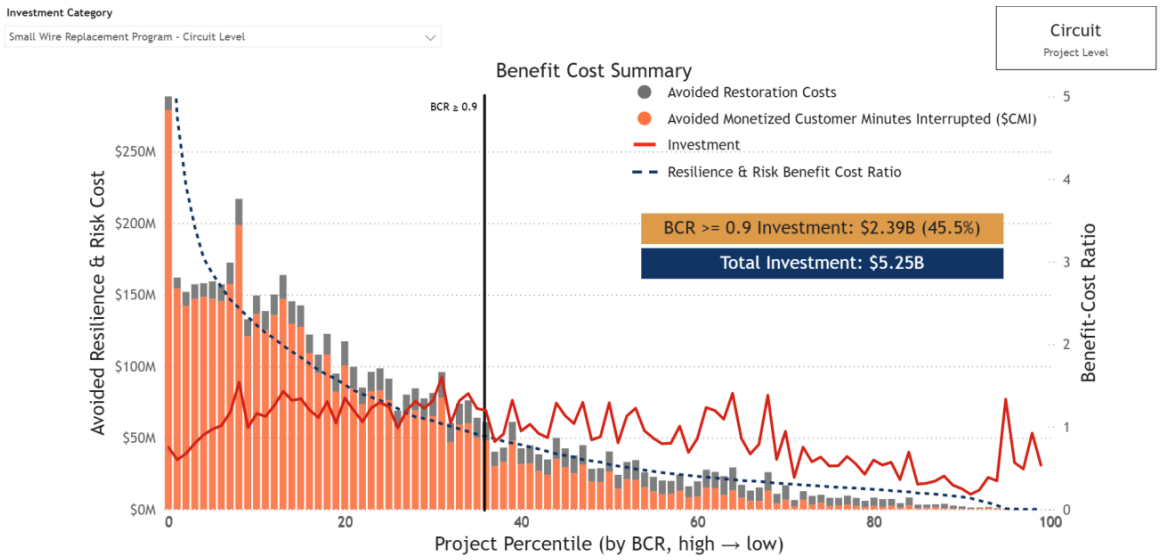


Figure 5-15 takes the benefit results from Figure 5-14 and layers in the expected resiliency investment for each circuit to show the Resilience, Reliability, & Risk BCR. As the figure shows, if this program were applied to the entire DTE system, the overall investment level would be approximately $5.25 billion. The weighted BCR for deploying this program across the entire system is 1.08. The figure shows that approximately $2.39 billion, or 45.5% of the total investment level, has a BCR ≥ 0.9. The weighted BCR for deploying this program on circuits where the BCR ≥ 0.9 is 2.09.

Figure 5-15: Small Wire Replacement Program BCR Summary



5.2.4 Qualitative Additional Benefits of the Program

The previous sections have outlined the results from quantifying the benefits of specific investments. As discussed, it is difficult to fully capture and quantify all the factors that go into every investment decision. For the Small Wire Replacement Program, an important set of benefits not fully reflected in the quantified Benefit-Cost Analysis relates to operational, safety, and system hardening considerations associated with proactively rebuilding small wire sections of the distribution primary overhead system.

Small wire is generally more vulnerable to failure under loading and vegetation interaction than more robust conductor configurations. As a result, proactively replacing small wire can provide qualitative benefits beyond those directly captured in the modeled resilience, reliability, and risk benefit streams. These benefits include reducing exposure to conductor-related safety hazards for the public and improving the overall operability and maintainability of the system. When small wire fails, repairs often must be performed reactively, potentially during major events, at night, or under extreme weather conditions. By reducing the frequency of these reactive replacement activities, the program can help reduce safety risk exposure for DTE crews and improve restoration working conditions.

The program may also provide broader system benefits that are difficult to quantify directly. Rebuilding protection zones that contain small wire can improve standardization of conductor configurations, reduce maintenance complexity, improve system capacity, and support more durable long-term system performance. In addition, these projects may improve service in localized areas that have historically experienced poorer reliability or greater exposure to storm and vegetation-related impacts. Accordingly, while the quantitative BCR results provide an important decision-making metric, the qualitative safety, operational, and system hardening benefits of the Small Wire Replacement Program may further support investment in projects that strengthen the distribution primary overhead system.

5.3 Breaker Replacement Program

This section includes the Benefit-Cost methodology and results for the Breaker Replacement Program. The section contains background information on the program and the approach used to estimate the number and costs of substation breakers and reclosers included in the analysis. The section also includes the program's Benefit-Cost results and outlines additional factors for consideration. The Breaker Replacement Program focuses on the replacement of aging breakers and substation reclosers that protect distribution circuits and help isolate faults within substations.

Additional information describing the substation asset base and the customer connectivity approach used in this analysis is provided in Section 2.1.2.

5.3.1 Background & Program Description

Substations serve as the heart of the electrical power system, acting as the central hub where electricity is transformed, protected, and routed from the transmission and subtransmission networks to distribution circuits that deliver power to customers. Within each substation, critical assets such as breakers and substation reclosers play an important role in isolating faults and maintaining the safe and reliable flow of electricity to distribution circuits and ultimately to customers. Because substations contain key protection equipment in a single location, failures of these devices can interrupt service to large portions of the distribution system, resulting in widespread

customer outages. Maintaining and monitoring these protection assets is therefore essential to supporting safe, reliable, and resilient grid operations.

Effective management of substation protection assets requires utilities to understand the age, configuration, and operational role of the equipment that supports these facilities. As breakers and substation reclosers age, the probability of failure increases, which can lead to equipment damage or extended service interruptions. Proactive planning and replacement of aging protection equipment enables utilities to reduce operational risk while also ensuring substations continue to perform their critical role in providing electricity to customers.

This program introduces substation equipment replacement modeling to evaluate the customer benefits associated with substation breakers and reclosers. The analysis establishes connectivity between these protection devices, the distribution circuits they serve, and the customers ultimately impacted by their operation. By linking breakers and substation reclosers to distribution circuits and customer counts, the analysis enables a more accurate evaluation of reliability benefits and customer impacts associated with substation protection investments.

5.3.2 Estimating Investment Activities and Cost

The analysis begins by identifying the population of breakers and substation reclosers using the substation asset register provided by DTE.

Investment costs for breaker and substation recloser replacements were developed using planning-level cost estimates provided by DTE. These estimates reflect the typical scope of work required to replace substation protection equipment.

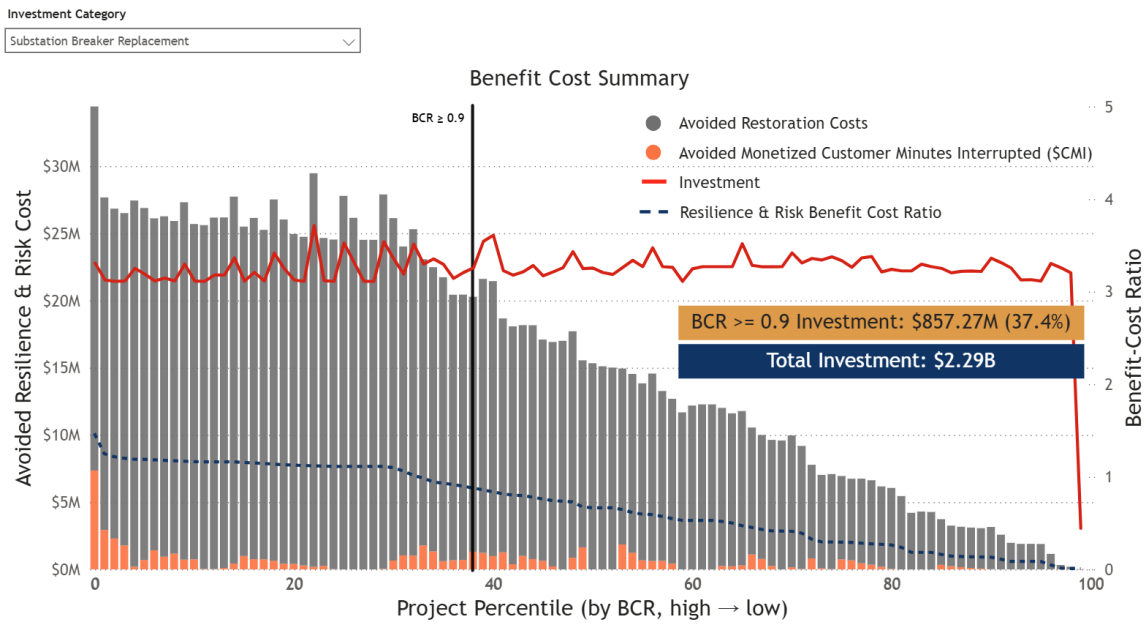
5.3.3 Quantitative Benefit-Cost Results

This section includes the quantified benefit results from the analytics models described in Section 4.4. 1898 & Co. evaluated the breaker replacement program, linking each breaker and substation recloser to the downstream distribution circuits and customers they protect. This connectivity enables a granular assessment of the reliability benefits associated with proactively replacing aging substation equipment. The evaluation organizes benefits and costs at the asset level. Quantified benefit

results reflect only the impacts of breaker and substation recloser replacement. To support comparison across projects with varying sizes and customer counts, results are presented on a percentile ranking basis using the BCR as the ranking metric. The results are shown in Figure 5-16.

As Figure 5-16 depicts, if this program were applied to the entire DTE distribution system, the overall investment level would be approximately $2.29 billion. The weighted BCR for deploying this program across the entire system is 0.69. The figure shows that approximately $857.27 million, or 37.4% of the total investment level, has a BCR ≥ 0.9. The weighted BCR for deploying this program is only on circuits where the BCR ≥ 0.9 and is 1.13.

Figure 5-16: Substation Breakers Benefit-Cost Analysis Summary



5.3.4 Qualitative Additional Benefits of the Program

The previous sections outlined the results from quantifying the benefits associated with specific investments. As discussed, it is difficult to fully capture and quantify all the factors that go into every investment decision. For the Breaker Replacement Program, several important operational and safety benefits are not fully captured in the quantified Benefit-Cost Analysis.

Breakers and substation reclosers serve as critical protective devices that quickly isolate faults and prevent fault current from propagating through the electrical system. If a breaker fails to operate as intended, high fault currents may continue flowing through substation and distribution equipment, potentially causing extensive damage to transformers, conductors, and other connected infrastructure. Modern replacement breakers are typically designed to operate more quickly and consistently, enabling faster fault clearing that limits the duration of fault currents on the system. By interrupting faults more rapidly, these devices reduce the thermal and mechanical stress placed on connected equipment, lowering the risk of widespread equipment damage.

In addition to equipment damage, sustained fault conditions can increase the likelihood of arc flash events, fires, or explosions due to the high energy present in the system. These conditions can pose significant safety risks to substation personnel and operations staff who may be working in or responding to events at the facility. Proactive replacement of aging breakers helps reduce the likelihood of faults.

Breaker replacement programs may also coincide with upgrades to modern protection and control systems, allowing utilities to improve protection coordination and ensure faults are detected and isolated more effectively across the system. These operational and safety improvements represent meaningful benefits of the Breaker Replacement Program that are not reflected in the quantified Benefit-Cost results.

5.4 URD Replacement Program

This section includes the Benefit-Cost methodology and results for the Underground Residential Distribution (URD) Replacement Program. The section provides background information on the program, describes the approach 1898 & Co. utilized to identify investment activities and estimate project costs, and summarizes the resulting Benefit-Cost findings. The section also outlines additional factors for consideration when interpreting the results. 1898 & Co. performed the Benefit-Cost Analysis using the Equipment Failure Mitigation Model methodology outlined in Section 4.4.

5.4.1 Background & Program Description

The URD Replacement Program is intended to improve the reliability and long-term performance of the DTE underground residential distribution system through the proactive replacement of aging underground cable. URD cable is a smaller-diameter, polyethylene-insulated conductor used primarily in underground residential areas on the distribution system. These cables are typically either directly buried or installed in conduit. Since URD cable is located below ground, it avoids many of the outage drivers that affect overhead facilities, such as vegetation contact, wind loading, and other weather-related impacts.

URD cable is generally more costly and labor-intensive to install, locate, and repair than overhead construction. Although failures may occur less frequently than for comparable overhead assets, they can be more difficult to identify, more time-consuming to repair, and more disruptive to customers when they occur. As a result, underground cable failures can still create meaningful reliability and restoration challenges, particularly as the cable population ages.

The URD Replacement Program reflects both the need to address aging underground infrastructure and the need for sustained reinvestment to support long-term reliability in underground residential areas. By proactively replacing older or higher-risk URD cable segments, DTE can reduce future failure risk, avoid reactive repair activities, and support more effective long-term asset management.

5.4.2 Estimating Investment Activities and Cost

URD replacement investments were included in this analysis to evaluate the reliability benefits associated with proactively replacing underground residential distribution cable on the secondary system. Incorporating URD assets into the Benefit-Cost Analysis (BCA) allows the model to quantify how replacement of higher-risk URD cable segments can reduce outage frequency and duration for residential customers.

The analysis begins by identifying the population of URD cable using DTE GIS information. This dataset includes attributes such as installation year, cable type, installation method, direct buried or conduit, and associated residential circuits. For

purposes of the analysis, cable installed in 1985 or earlier is assumed to be non-tree-retardant. Using the population asset characteristics identified in the DTE provided data, the model identifies the applicable URD cable segments and estimates the replacement activity evaluated within the planning horizon.

Investment costs for URD cable replacement were developed using unit cost estimates provided by DTE. These estimates reflect the typical scope of work required to replace URD cable, including the expected construction approach and associated installation practices. The resulting replacement quantities and costs serve as inputs to the Equipment Failure Mitigation Model used to estimate the reliability benefits of the program.

5.4.3 Quantitative Benefit-Cost Results

1898 & Co. evaluated this program comprehensively across DTE's underground residential distribution cable. The evaluation organized the benefits and costs of this program at the protection zone level. This section includes the quantified benefit results from the Equipment Failure Mitigation Model described in Section 4.4.

The quantified benefits results for this program were aggregated to the protection zone level. For ease of representing this level of information, the quantified benefit results are shown on a percentile ranking basis. The ranking is based on the BCR.

Figure 5-17 includes the expected avoided customer outage benefits for the URD Replacement program. The figure consists of the absolute benefit in CMI and the percentage improvement. The figure also includes which protection zones have a quantified BCR ≥ 0.9. As the figure shows, approximately 12% of the protection zone percentiles have a BCR ≥ 0.9. For these protection zone percentiles, the evaluation shows an average expected improvement in CMI of approximately 96%, ranging from 94% to 97%, in the percentile ranking view.

Figure 5-17: URD Replacement Program Avoided Customer Outage Benefit

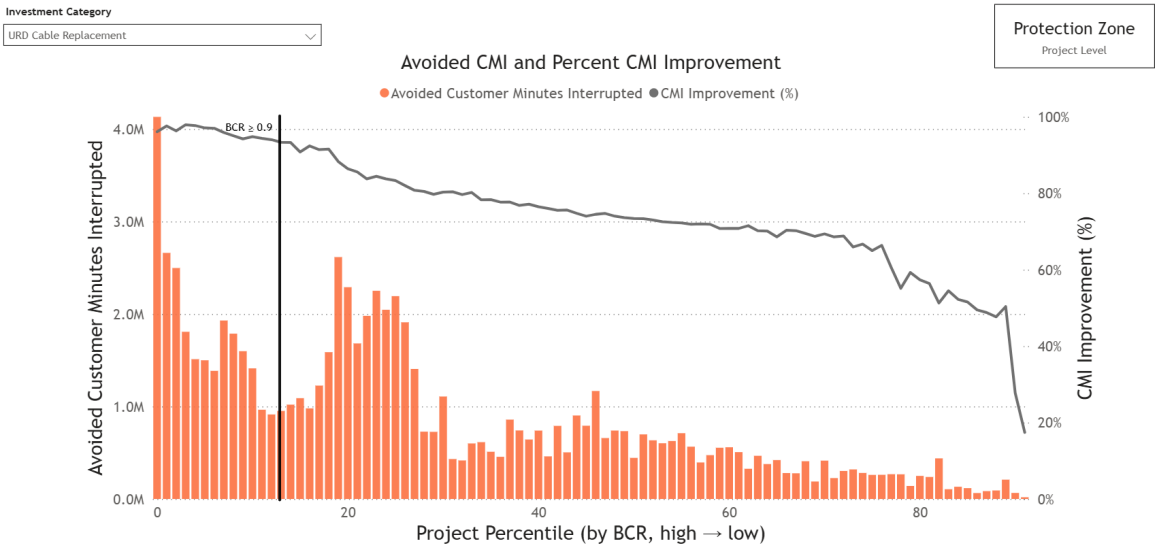


Figure 5-18 takes the CMI benefits from Figure 5-17 and applies the ICE Calculator (see Section 4.2) to monetize the outages and adds the avoided restoration costs for each circuit. It is important to note that the application of the ICE Calculator incorporates the various customer types into the evaluation. This figure shows the total monetized resilience and risk benefits of this program. The figure also includes the expected improvement in monetized customer outages and restoration costs. The protection zones with a BCR ≥ 0.9 show an improvement in monetized customer outages of 96% on average, ranging from 95% to 98%, and 97% on average for restoration costs, ranging from 96% to 99%, in the percentile ranking view.

Figure 5-18: URD Replacement Program Benefits Summary

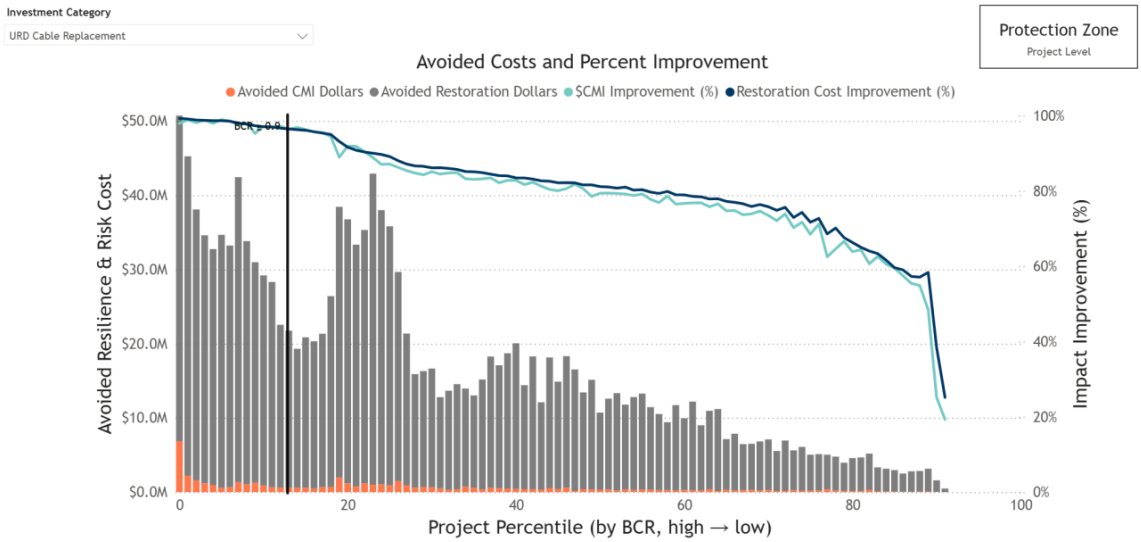
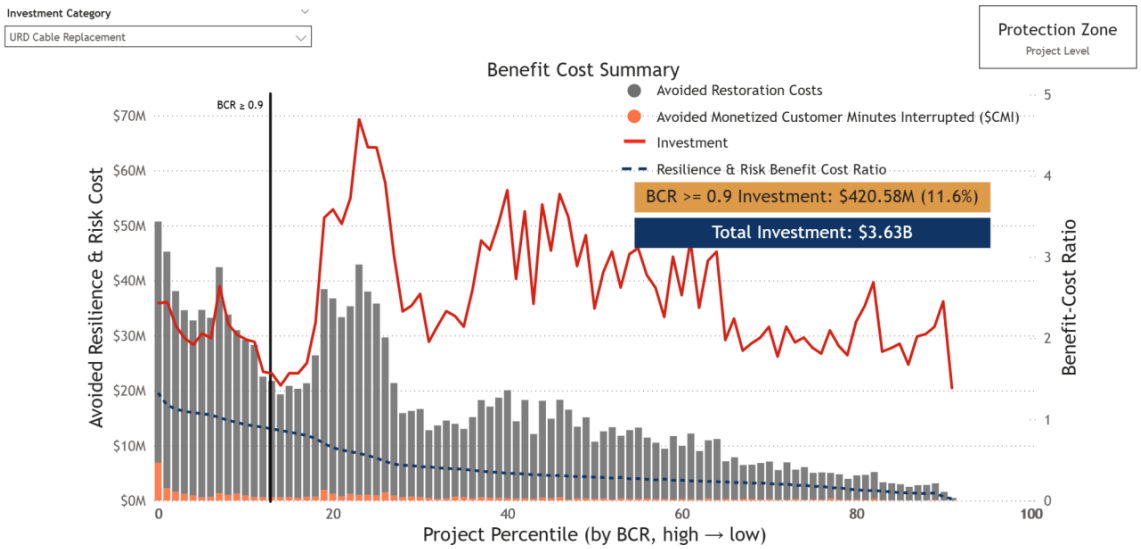


Figure 5-19 takes the benefit results from Figure 5-18 and layers in the expected investment for each circuit to show the BCR. As the figure shows, if this program were applied to the entire DTE system, the overall investment level would be approximately $3.63 billion. The weighted BCR for deploying this program across the entire system is 0.69. The figure shows that approximately $420.58 million, or 11.6% of the total investment level, has a BCR ≥ 0.9. The weighted BCR for deploying this program is only on circuits where the BCR ≥ 0.9 is 1.06.

Figure 5-19: URD Replacement Program BCR Summary



5.4.4 Qualitative Additional Benefits of the Program

The previous sections have outlined the results from quantifying the benefits of specific investments. As discussed, it is difficult to fully capture and quantify all the factors that go into every investment decision. For the URD Replacement Program, a key set of benefits not fully reflected in the quantified Benefit-Cost Analysis relates to operational, customer, and safety considerations associated with proactively replacing underground residential cable.

Although URD cable is generally less exposed to common overhead outage drivers such as vegetation contact and weather-related damage, failures can be difficult to identify, locate, and repair when they occur. As a result, underground cable failures can be particularly disruptive to customers and can require more complex restoration activities than comparable overhead repairs. Proactively replacing higher-risk URD cable segments can therefore provide qualitative benefits beyond those directly captured in the modeled reliability benefit streams.

The program may also provide important customer and community benefits that are difficult to monetize directly. Because underground cable failures can take longer to isolate and repair, proactive replacement can help reduce the customer frustration, inconvenience, and uncertainty associated with extended residential outages. In addition, the program can improve the long-term operability and maintainability of the underground residential system by reducing the need for reactive repairs and supporting a more planned approach to asset replacement.

There are also safety-related benefits associated with reducing reactive underground repair work. Repairs to failed underground cable may require excavation, fault locating, and work in challenging field conditions, sometimes during periods of heightened customer impact or adverse weather. By reducing the frequency of these reactive activities, the URD Replacement Program can help reduce safety exposure for DTE crews and contractors while also improving the efficiency and predictability of restoration work. As such, while the quantitative evaluation captures the direct

reliability benefits of the program, the qualitative operational, customer, and safety benefits further support the value of continued investment in URD cable replacement.

5.5 Cable Replacement Program

This section includes the Benefit-Cost methodology and results for the Cable Replacement Program. The section provides background information on the program, describes the approach 1898 & Co. utilized to identify investment activities and estimate project costs, and summarizes the resulting Benefit-Cost findings. The section also outlines additional factors for consideration when interpreting the results. 1898 & Co. performed the Benefit-Cost Analysis using the Equipment Failure Mitigation Model methodology outlined in Section 4.4 above.

5.5.1 Background & Program Description

The Cable Replacement Program is intended to improve the reliability and long-term performance of the DTE underground distribution and subtransmission system through the proactive replacement of system cable. System cable is a large diameter, insulated conductor typically installed in conduit, with manholes, vaults, or switch cabinets located at intervals along the route to allow crews to pull cable through the conduit system and splice segments together. This configuration supports the operation of underground facilities in areas where overhead construction is not practical or where multiple circuits must pass through constrained corridors, such as approaches to substations, dense urban areas, and other critical portions of the system. In many cases, system cable also serves downtown customers, major public venues, critical infrastructure, or links substations to overhead circuits.

Because system cable is installed underground, it is generally less exposed to common overhead outage drivers such as vegetation contact, wind, and other weather-related impacts. This can provide important resilience and reliability advantages relative to overhead construction. At the same time, underground system cable is significantly more complex and costly to install, locate, repair, and replace. When failures occur, restoration activities can be labor intensive and time consuming, often requiring specialized construction methods and coordination to access the failed section.

For this reason, system cable plays an important role in the overall operation and reliability of the underground network, particularly in locations where redundancy and alternate sourcing are needed to limit customer impacts during an outage. Because these assets often serve dense load areas, critical facilities, and highly visible community locations, system cable failures can result in broader customer and community impacts than a typical overhead outage. When a system cable failure occurs, the ability to transfer load to an alternate source can help reduce the duration and extent of outages. Accordingly, the Cable Replacement Program reflects the need for continued reinvestment in underground infrastructure to maintain long-term reliability, reduce future failure risk, and support more effective long-term asset management in critical underground portions of the system.

5.5.2 Estimating Investment Activities and Cost

System cable replacement investments were incorporated into this analysis to evaluate the reliability benefits associated with proactively replacing underground system cable across DTE's distribution and subtransmission networks. Including these assets in the Benefit-Cost framework allows the model to quantify how replacement of higher-risk system cable segments can reduce failure risk, improve restoration performance, and mitigate the potential for larger customer interruptions where underground system cable serves as a critical part of the network configuration.

The analysis begins by identifying the population of system cable segments using DTE's underground asset inventory. This dataset includes key asset attributes such as cable type, installation year, voltage, and associated circuit or substation connections. As part of the modeling assumptions, cable installed in 1991 or earlier is assumed to be non-tree-retardant. Using this asset population and related characteristics, the model identifies the applicable system cable segments to be included in the program and estimates the associated replacement activity over the planning horizon.

Investment costs for system cable replacement were developed using planning-level cost estimates provided by DTE. These estimates reflect the typical scope of work required to replace underground system cable, including the expected construction

approach and associated installation practices. The resulting replacement quantities and costs were then used as inputs to the Equipment Failure Mitigation Model to estimate the reliability benefits associated with the program.

5.5.3 Quantitative Benefit-Cost Results

1898 & Co. evaluated this program comprehensively across DTE's underground distribution and subtransmission system cable. The evaluation organized the benefits and costs of this program at the circuit level. This section includes the quantified benefit results from the Equipment Failure Mitigation Model described in Section 4.4.

The quantified benefits results for this program were aggregated to the circuit level. For ease of representing this level of information, the quantified benefit results are shown on a percentile ranking basis. The ranking is based on the BCR.

Figure 5-20 includes the expected avoided customer outage benefits for the Cable Replacement program. The figure consists of the absolute benefit in CMI and the percentage improvement. As the figure shows, approximately 28% of the circuit percentiles have a BCR ≥ 0.9. For these circuit percentiles, the evaluation shows an average expected improvement in CMI of approximately 96%, ranging from 92% to 98%, in the percentile ranking view.

Figure 5-20: System Cable Program Avoided Customer Outage Benefit

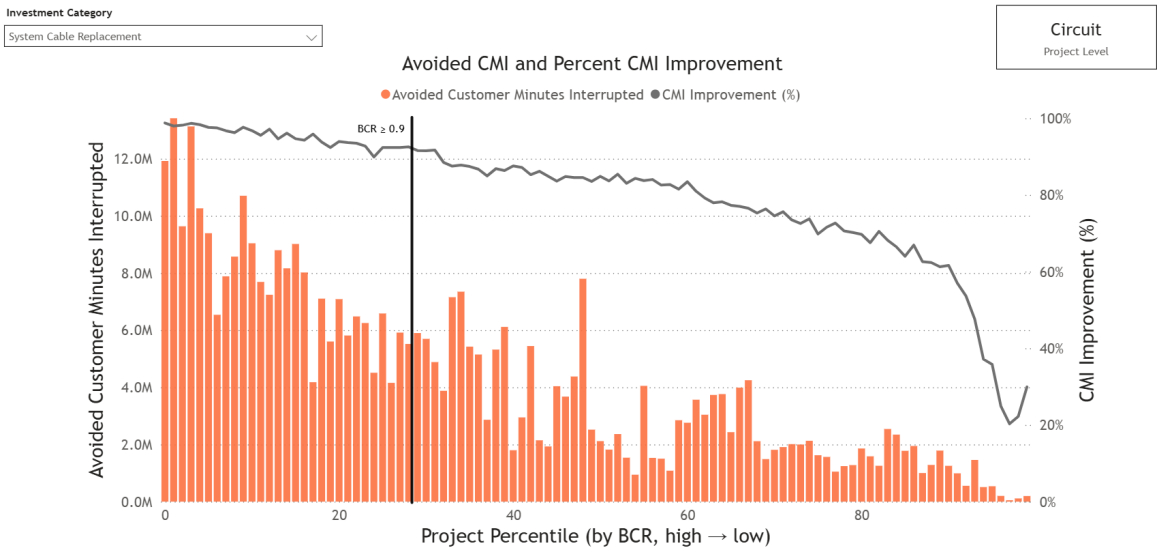


Figure 5-21 takes the CMI benefits shown in Figure 5-20 and applies the ICE Calculator (see Section 4.2) to monetize the outages and adds the avoided restoration costs for each circuit. It is important to note that the application of the ICE Calculator incorporates the various customer types into the evaluation. This figure shows the total monetized resilience and risk benefits of this program. The figure also includes the expected improvement in monetized customer outages and restoration costs. The circuits with a BCR ≥ 0.9 show an improvement in monetized customer outages of 98% on average, ranging from 96% to 99%, and 97% on average for restoration costs, ranging from 96% to 98%, in the percentile ranking view.

Figure 5-21: System Cable Replacement Program Benefits Summary

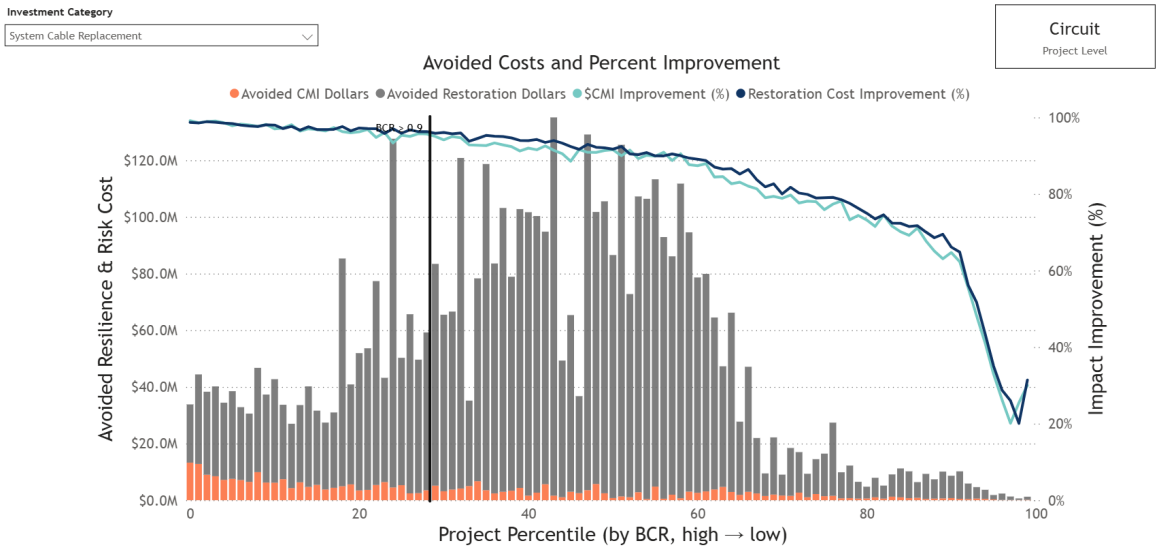
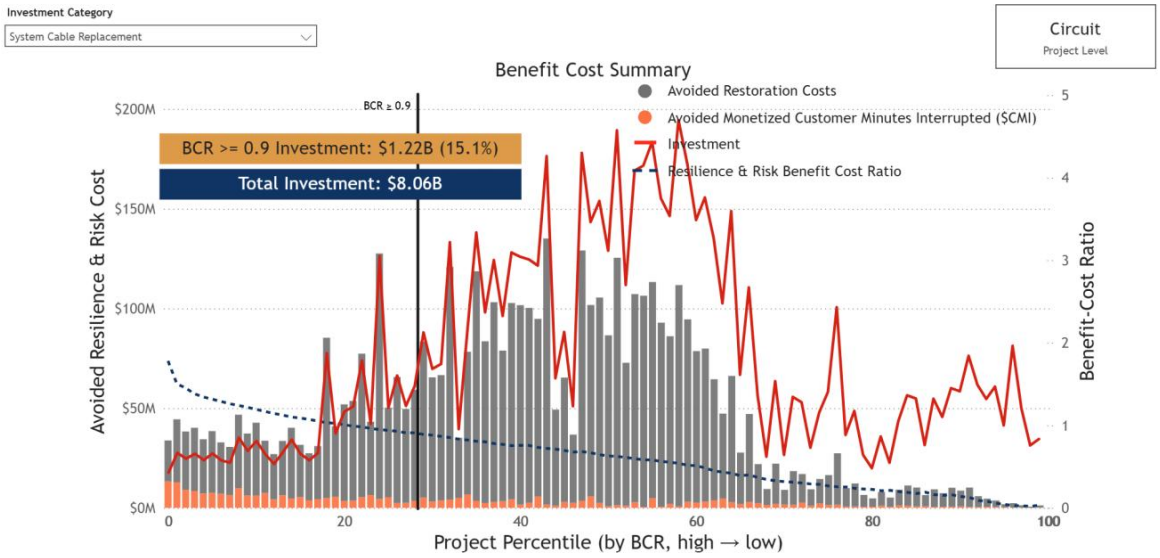


Figure 5-22 takes the benefit results shown in Figure 5-21 and layers in the expected investment for each circuit to show the BCR. As Figure 5-22 shows, if this program were applied to the entire DTE system, the overall investment level would be approximately $8.06 billion. The weighted BCR for deploying this program across the entire system is 0.61. The figure shows that approximately $1.22 billion, or 15.1% of the total investment level, has a BCR ≥ 0.9. The weighted BCR for deploying this program only on circuits where the BCR ≥ 0.9 is 1.09.

Figure 5-22: System Cable Replacement Program BCR Summary



5.5.4 Qualitative Additional Benefits of the Program

The previous sections have outlined the results from quantifying the benefits of specific investments. As discussed, it is difficult to fully capture and quantify all the factors that go into every investment decision. For the Cable Replacement Program, a key set of benefits not fully reflected in the quantified Benefit-Cost Analysis relates to operational, customer, and safety considerations associated with proactively replacing underground cable.

Although system cable is generally less exposed to common overhead outage drivers such as vegetation contact and weather-related damage, failures can be difficult to identify, locate, and repair when they occur. System cable is a large-diameter cable that is a critical part of the distribution and subtransmission system and supports grid redundancy and resiliency. When failures occur on system cable service can be disrupted to many DTE customers for long durations as it requires more complex restoration activities than comparable overhead repairs. Additionally, system cable also serves downtown districts and major public venues where outage impacts can have greater societal impacts.

Proactively replacing higher-risk system cable segments can therefore provide qualitative benefits beyond those directly captured in the modeled reliability benefit streams.

The program may also provide important customer and community benefits that are difficult to monetize directly. Since the failure of system cable takes longer to isolate and repair, impacts many DTE residential and C&I customers, and reduces system redundancy when out of service, proactive replacement helps reduce the customer frustration, inconvenience, and uncertainty associated with extended outages. In addition, the program can improve the long-term operability and maintainability of the underground system by reducing the need for reactive repairs and supporting a more planned approach to asset replacement.

There are also safety-related benefits associated with reducing reactive underground repair work. Repairs to failed underground cables may require excavation, work in challenging field conditions, and repairs during periods of heightened customer impact or adverse weather. By reducing the frequency of these reactive activities, the Cable Replacement Program can help reduce safety exposure for DTE crews and contractors while also improving the efficiency and predictability of restoration work. As such, while the quantitative evaluation captures the direct reliability benefits of the program, the qualitative operational, customer, and safety benefits further support the value of continued investment in system cable replacement.

5.6 Subtransmission SCADA

This section includes the subtransmission SCADA program's Benefit-Cost methodology and results. The section includes background information on the program and the approach 1898 & Co. utilized to estimate the cost to enable subtransmission SCADA on the system. The section also includes the program's Benefit-Cost results and outlines additional factors for consideration.

1898 & Co. performed a Benefit-Cost Analysis across the applicable DTE subtransmission system using the Resilience Model methodology outlined in Section 4.3 above. The evaluation quantified the reliability, resilience, and risk-reduction

benefits of placing Automatic Pole Top Switches (APTS) on the different trunk (TRK) and tie (TIE) lines of the DTE subtransmission system.

5.6.1 Background & Program Description

The DTE subtransmission system serves as a critical link between the ITC transmission system and the DTE distribution system and is used to supply power to customer-dedicated substations across the DTE service area. Due to the critical role the subtransmission network plays in moving power across the DTE system and serving customers, the system is designed to provide redundant sources of power to distribution substations and circuits that directly serve customers. This redundancy helps provide service to customers during planned outages or during contingency situations such as unplanned equipment outages.

To enable supporting contingency situations the subtransmission circuits are configured as either a trunk (TRK) line or a tie (TIE) line. Trunk lines are configured to provide power as a radial circuit having one source station that can feed one or more distribution substations. The tie line is a network configured circuit and can have multiple source stations that can feed multiple distribution substations. Examples of trunk and tie lines are provided in Figure 5-23 and Figure 5-24. As shown in the figures, the DTE subtransmission system is configured to provide redundancy during outage events. For trunk lines, affected transformers that are serving customers can sometimes be switched to different trunk lines (Figure 5-23). For tie lines, faults can be isolated through switching and transformers can continue to serve customers from one of the two stations serving the tie line (Figure 5-24).

In addition to the redundancy of the subtransmission circuits, each substation can also be configured with redundancy and reliability schemes. For example, the substation may be configured with an Automatic Throwover (ATO) and/or an Emergency Load Control scheme. As shown in Figure 5-23, substation B has two transformers, an ATO scheme, and an ELC scheme in place. If a fault on TRK line 1 caused the customers served by transformer 1 to lose power, the ATO can activate and shift (throwover) customers served by transformer 1 to transformer 2. However, if the demand of

moving customers exceeds the capacity of transformer 2 the ELC scheme could block the throwover from occurring.

Figure 5-23: Example Trunk Line Configuration

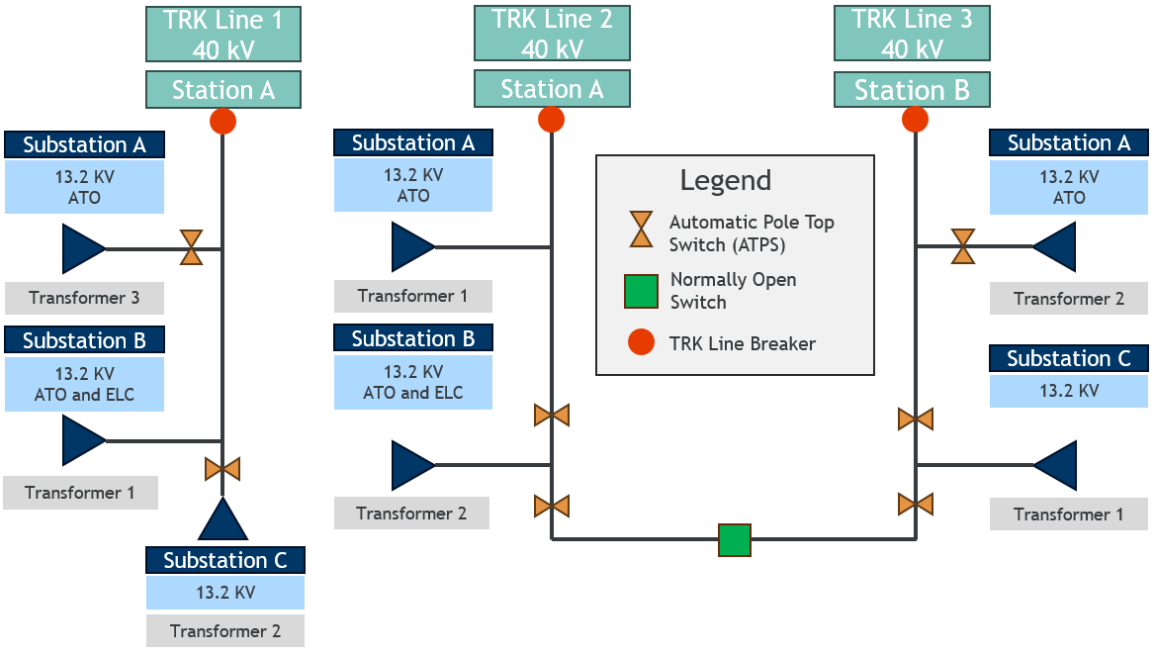
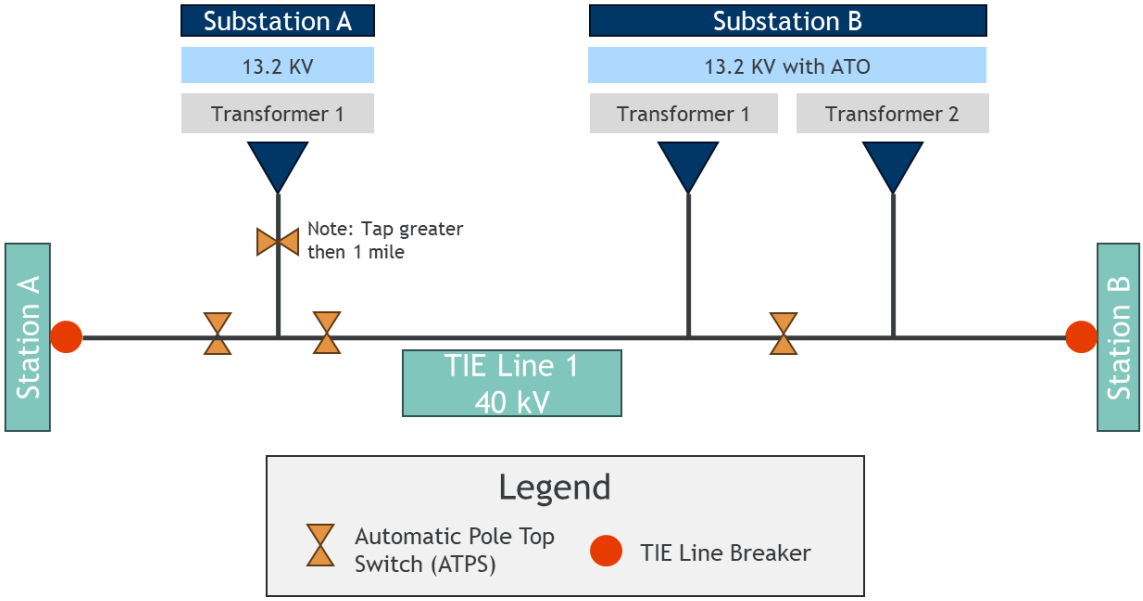


Figure 5-24: Example Tie Line Configuration



Additionally, if a fault occurs on a trunk or tie line for a single transformer substation, such as substation A in Figure 5-24, switches need to be in place to minimize customer impact and leverage the redundancy of the subtransmission system.

To build upon and improve on the benefits of the redundancy in the subtransmission system, outages can be reduced and mitigated through the deployment of a coordinated system of switches known as Automatic Pole Top Switches (APTS). Using APTS allows the subtransmission system to sectionalize and isolate faults while maintaining service to customers in single contingency failure events. For example, a fault on a tie line can be isolated by opening a strategically placed APTS, allowing a single source, on one side of the fault, to continue serving customers.

As can be seen in Figure 5-23 and Figure 5-24, the subtransmission system serves multiple substations and transformers that in total can serve thousands of DTE customers. Faults on the subtransmission system can lead to longer restoration times, when APTS are not present, causing interruption of service to thousands of DTE customers. This creates the opportunity to gain benefits through the deployment of SCADA enabled APTS which can leverage the redundancy of the subtransmission through the automatic isolation of faults on the subtransmission system.

5.6.2 Estimating Investment Activities and Cost

This section outlines the systematic approach used by 1898 & Co. to identify investment activities for the program and estimate their expected costs. In this analysis, 1898 & Co. performed a system-wide, rules-based analysis to evaluate both the number of APTS to add and the trunk and tie lines to which to add them.

DTE provided substation-level indicators to identify locations with Automatic Throwover (ATO) schemes, Emergency Load Control (ELC) schemes, and stations operating at or above 90 percent of firm rating. DTE also provided data identifying trunk and tie lines and the number of customers served by each. Using these inputs, the analysis applied a rules-based framework to estimate the total APTS required to support these operating conditions across the system. Existing DTE APTS were then

incorporated by subtracting the estimated existing APTS from the rules-based necessary APTS quantities to calculate the incremental APTS needed.

A high-level overview of the general rules applied to determine APTS count is outlined below:

TRUNK Lines:

1) For single transformer substations, add APTS to isolate faults downstream of that substation tap.
2) For multiple transformer substations, which exceed 90% of the transformer firm rating, place APTS to isolate faults downstream of that substation tap. As an example, see substation B on TRK line 1 in Figure 5-23
3) For trunk lines with a normally open point and serving at least one substation exceeding 90% of its firm rating, place APTS to create a tie to an adjacent circuit. This enables restoration of that substation without relying on the automatic throwover (ATO) as that can result in the Emergency Load Control (ELC) scheme operating and the potential loss of customers. As an example, placement of APTS on both sides of the substation transformer tap as shown at substation B in Figure 5-23
4) If a substation served from a trunk line has a tap that exceeds one mile, place an APTS. This supports reducing risk of outage exposure and potential voltage violations. As an example, see substation A on TRK line 3 in Figure 5-23

TIE Lines:

1) For a single transformer substation served, apply APTS to both sides of the tap to the substation. As an example, see substation A in Figure 5-24.
2) For a multiple transformer substation with an automatic throwover (ATO) place an APTS between the transformer taps. As an example, see substation B in Figure 5-24.

3) If a substation served from a tie line has a tap that exceeds one mile, place an APTS. This supports reducing risk of outage exposure and potential voltage violations. As an example, see substation A in Figure 5-24.

Because existing APTS information is available at the subtransmission line level, specific switch locations were not evaluated in this planning-level assessment. Therefore, the model distributes existing APTS across the substations associated with each trunk or tie line. This approach can produce fractional existing APTS values at the substation level and, as a result, fractional incremental APTS requirements. Further engineering review would be needed to determine the optimal switch placement and the exact mix of trunk versus tie-line installations for individual projects; however, for purposes of this planning-level assessment, the proportional allocation approach provides a reasonable system-level estimate of incremental APTS needs and associated investment. The next section provides the quantitative Benefit-Cost results for the analysis.

5.6.3 Quantitative Benefit-Cost Results

To evaluate the benefits of implementing APTS, 1898 & Co. used the resiliency model to evaluate weather-event-induced failures of subtransmission assets, which can result in customer outages. The model then evaluated the outage-reduction benefits available from deployment of additional APTS on the subtransmission system. The benefit evaluation considered subtransmission and substation configurations capable of reducing the duration of individual outages, though not the number of such outages.

The DTE OMS records contained only a small number of subtransmission-system outages, which limited the ability to directly determine subtransmission-system-asset probability of failure (POF) rates. Therefore, 1898 & Co. considered subtransmission-pole and pole-top failures to be similar in nature to distribution pole and pole-top failures. The analysis assigned to each subtransmission asset the probability of failure (POF) values of the corresponding distribution asset. For example, a Class 3

subtransmission pole received the POF values calculated for a Class 3 distribution pole. When considering the impact of a weather event on an entire subtransmission trunk or tie line, the failure of any single asset on the line (i.e., pole or pole top) would result in a subtransmission line outage. Therefore, the subtransmission line's POF for a particular weather event was equal to the probability that one-or-more of the line's assets (i.e., pole or pole top) failed during the weather event.

Since subtransmission SCADA investment activities did not include asset replacements, a subtransmission line's investment (INV) POFs (one per weather event type) were assumed to be the same as its status quo (SQ) POFs. Given the limited data available about historical subtransmission outages and the redundancy in the design of both subtransmission circuits and the substations those circuits serve, this analysis assumed that without installing APTS (i.e., under the status quo case), a subtransmission outage's duration was 45 minutes. In this SQ case, each of these outages had the potential to impact thousands of customers. After installing subtransmission SCADA, (i.e., under the INV case), each subtransmission outage's duration was assumed to be 5 minutes.

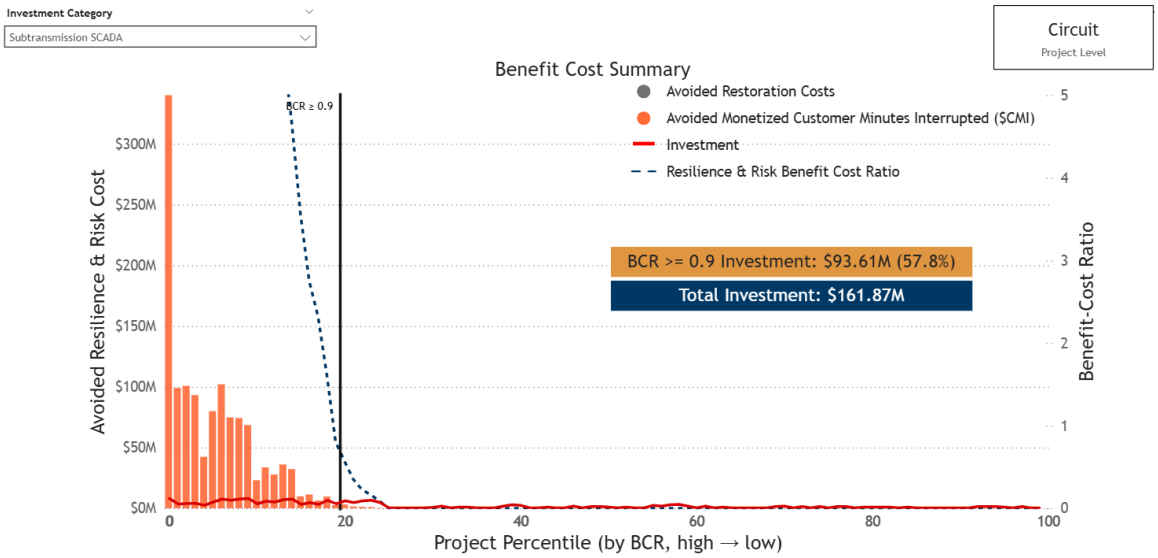
Given these assumptions, a subtransmission line's SQ customer minutes interrupted (CMI) for a failure equaled the 45-minute duration multiplied by the number of customers impacted. Similarly, the subtransmission line's INV CMI (that is the CMI after the SCADA investment activity) for a failure equaled the 5-minute duration multiplied by the customer count. CMI-cost calculations applied ICE calculator values to the outage durations using the customer quantities by type. The number of customers without power during a subtransmission outage was based on the number of customers served by those substations fed by the particular trunk or tie line. The customer-outage calculation also considered potential outage reductions due to substation ATO and/or ELC schemes, which can mitigate outages downstream of a transformer by shifting or shedding load.

Existing APTS switches were also considered in the analysis. 1898 & Co. identified existing APTS using GIS-based connectivity information and incorporated those switches into the calculation of the incremental investment needed. In cases where

existing APTS were already present, only the additional switches needed beyond the existing configuration were attributed to the investment activity. To reflect this in the benefits analysis, outage-reduction benefits were scaled based on the share of total APTS that were incremental rather than already in place. This approach was intended to recognize that existing system automation may already provide a portion of the outage mitigation benefit.

The results shown in Figure 5-25 consider the quantity of APTS, the benefits received by reducing customer interruptions, and the costs of placing APTS. The total investment cost was based on adding 352 new APTS switches across both trunk and tie lines based on the rules outlined in 5.6.2. Of the potential $161.87M of investment in subtransmission SCADA, $93.61M or 57.8% of total investment has a BCR ≥ 0.9. This analysis demonstrates the potential for specific parts of the DTE system to receive strong benefits from the deployment of APTS.

Figure 5-25: Subtransmission SCADA BCR Summary



5.6.4 Qualitative Additional Benefits of the Program

There are additional benefits associated with investment in the Subtransmission SCADA Program that 1898 & Co. did not monetize in this analysis. These include potential benefits in capacity or load constrained areas of the DTE system, where faster fault isolation and service restoration may help reduce operational challenges

and improve system flexibility during outage conditions. The program can also provide important safety benefits by reducing the time required to identify, isolate, and restore faults, which can reduce field exposure for crews and support a more controlled restoration process.

Additional switches and included sensors provide visibility into system events, better granularity on fault locations, and minimize the amount of time to patrol circuits to find a fault. For example, APTS installed at connection points between circuits can enable remote operations to quickly restore customers during an outage. This is currently done by crews in the field, which is known as restore before repair, and delays their ability to go directly to the damage and begin repairs. Both of these field restoration practices will receive benefit from installing APTS as the time that customers experience an outage will be reduced.

5.7 Distribution Automation

This section includes the distribution automation program's Benefit-Cost methodology and results. The section includes background information on the program and the approach 1898 & Co. utilized to estimate the scope and cost to enable distribution automation on the system. The section also includes the program's Benefit-Cost results and outlines additional factors for consideration. 1898 & Co. performed a comprehensive Benefit-Cost Analysis across the entire DTE system using the Outage Mitigation Modeling methodology outlined in Section 4.5. The analysis was performed across three different investment alternatives: Sectionalization, Automating Existing Ties, and Building New Ties.

5.7.1 Background & Program Description

Every year DTE customers experience thousands of outages, disrupting homes, businesses, and critical services. The system saw approximately 8 billion Customer Minutes Interrupted (CMI) and 15 million Customer Interruptions (CI) over the past five years, with outages lasting an average of 525 minutes per event, according to OMS data. These disruptions impact daily life and challenge long-term system resilience, reliability, and safety. These outages stem from a wide range of system stressors and

equipment failures; as a result, directly addressing each cause can require significant investment. Distribution Automation (DA) offers a cost-effective solution to improve outcomes by reducing the impact of outages when they occur. While DA does not prevent faults from happening, it provides the important capability to reduce the customer impacts across a wide range of outage types.

Recognizing DA's meaningful ability to improve the customer experience, DTE is continuing to invest in these capabilities through a two-part DA program. DTE's DA program has two sub-programs. The first sub-program is targeted toward safety risk mitigation. For the 4.8 kV distribution system, events may occur where the existing substation protection does not identify a fault current and appropriately lockout. In these instances, there can be live-wire situations, which can create serious safety concerns. The first sub-program includes installing a recloser immediately outside the substation to address this safety risk. The BCA provided by 1898 & Co. does not include costs and benefits for the investment activities within this safety-focused sub-program.

Instead, the BCA represents the costs and benefits of the second sub-program, which targets improvement of reliability. This sub-program includes investment in smart and connected protection devices to increase sectionalization and enable automated switching, minimizing the impact to customers from disruptive events.

A unique aspect of implementing DA across DTE's system is the presence of multiple voltage levels across circuits, leading to the identification of hybrid circuits that operate at more than one voltage. To account for these complexities, 1898 & Co. collaborated with DTE to develop a structured decision matrix framework to guide the classification and analysis of these circuits.

1898 & Co. leveraged Geographic Information System (GIS) and Outage Management System (OMS) data to establish a study foundation, further enabling investment recommendations that align with system constraints and operational feasibility. The following sections detail the methodology and key results from this analysis.

5.7.2 Estimating Investment Activities and Cost

This section outlines the systematic approach employed by 1898 & Co. to identify investment activities for the program and estimate their expected costs. As discussed in Section 4.5, the evaluation considers three scenarios for distribution automation investments, each with their respective cost components. The following provides the approach employed by 1898 & Co. and DTE to estimate each of the three cost components (if any) for deploying distribution automation across the DTE system:

- **Sectionalization:** This investment includes adding sectionalizing reclosers to isolate outage-causing faults. 1898 & Co. evaluated each circuit's current state to identify the number of reclosers to include on each circuit. This involved identifying circuits with existing reclosers and SCADA. 1898 & Co. worked with DTE to establish which existing reclosers needed replacements and which ones could be leveraged for automation (Form 6). For 13.2kV circuits without SCADA, 1898 & Co. calculated costs for a recloser outside the station to provide necessary communications support for distribution automation schemes. For the reliability-focused recloser deployment, a decision matrix was used to determine the number of sectionalizing reclosers that could be added, adhering to the maximum thresholds set by DTE for each circuit. The following includes an overview of the decision matrix:
    - For 4.8 kV circuits with fewer than 400 customers, no sectionalizing reclosers were assigned. Circuits with 400+ customers received 2.5 sectionalizing reclosers, estimated to create 2 sectionalized pods. Because of the complexity of the 4.8kV circuit ring configurations, more than one sectionalizing recloser is required to create an isolated section. Based on the unique configuration of each circuit, the number of reclosers required may vary, but it is typically 2 or 3. Therefore, this analysis used a system-wide assumption of 2.5
    - For 13.2 kV and 8.3 kV circuits, those with fewer than 400 customers were not assigned any sectionalizing reclosers. Circuits with more than 400 customers received a number of midpoint reclosers equal to the

total number of customers on the circuit divided by 400 minus 1. The approach rounded down and placed a cap of five reclosers per circuit.

DTE provided the cost per recloser, including device placement and ongoing maintenance. Based on this and the number of reclosers for each circuit, 1898 & Co. estimated the cost for recloser deployments for each circuit.

- **Automate Existing Ties**: This investment enables the automated transfer of customers between circuits. Utilizing GIS data, 1898 & Co. identified manual tie switch locations between circuits of the same voltage for potential locations for upgrading to a tie recloser. Based on sectionalized pod counts and potential tie locations, 1898 & Co. estimated the number of manual tie switches to convert to automated reclosers for each circuit.
- **Build New Ties**: This investment involves constructing new tie lines for circuits that do not have an existing tie point. 1898 & Co. estimated the scope of adding new tie lines to circuits that do not have existing tie points. Utilizing geospatial analytics and GIS data, 1898 & Co. identified the shortest connection distance between two circuits and applied routing factors to estimate the amount of new tie construction. 1898 & Co. takes a conservative approach in estimating tie line distance by using the Manhattan distance method. While 1898 & Co.'s geospatial analysis identifies two points that are close together, the model does not assume the distance is "as the crow flies" (i.e., the shortest straight-line connection). To provide a more realistic estimate of construction distance, the model assumes the route forms a right angle between the two connection points and travels along these perpendicular segments for the calculation of tie length and cost.

  The routing factor is applied as follows:

$$Estimated\ Tie\ Line\ Dis\tan c\ e\ = \sqrt{2} \times\ Shortest\ Connection\ Distance$$

  This approach reasonably approximates the additional routing distance that may occur due to roadway alignments, right-of-way constraints, terrain, and other physical barriers, while maintaining a conservative estimate of tie

construction scope and cost. Based on install costs per mile from DTE, 1898 & Co. estimated the cost to add new tie lines to each circuit that did not have existing tie points.

5.7.3 Quantitative Benefit-Cost Results

This section presents the quantified benefits of the Distribution Automation Program that leverages the Outage Mitigation Modeling approach outlined in Section 4.5. 1898 & Co. comprehensively evaluated distribution circuits across DTE's distribution system. Circuits with fewer than 400 total customers are not eligible for distribution automation in accordance with DTE operational guidelines. Out of 2,640 distribution circuits identified with customers in GIS, 1,838 circuits were eligible for investment based on the customer count minimum. This exclusion of smaller circuits ensures that DA investments are targeted toward areas likely to produce the most customer benefit.

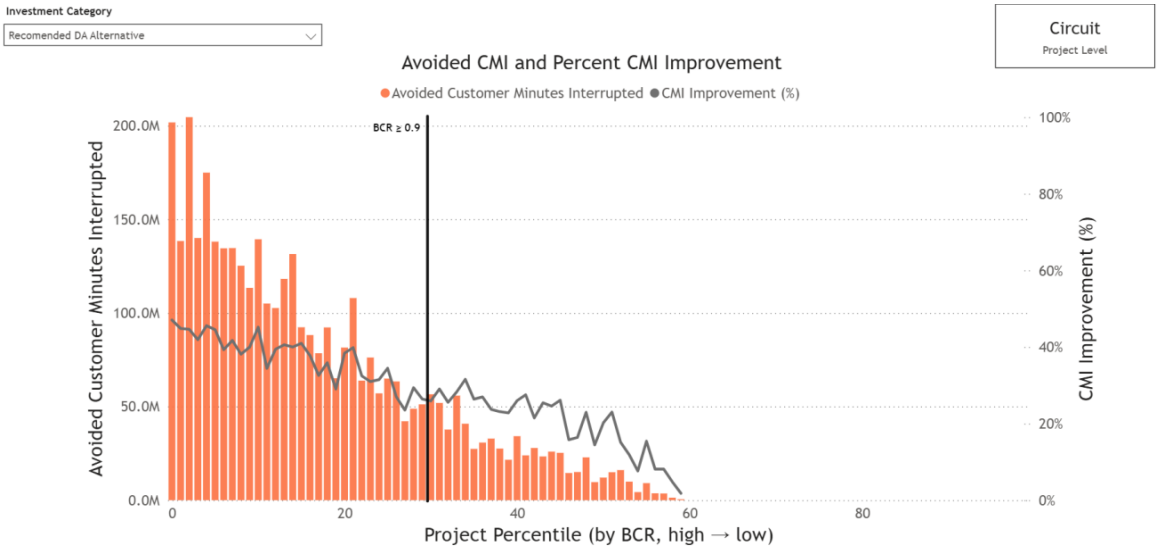
As discussed above, the evaluation considered three scenarios: Sectionalization only, Automating Existing Ties, and Building New Tie Lines. 1898 & Co. leveraged the Benefit-Cost Analysis to identify the recommended alternative from these three, specifically selecting the most mature scenario with a Benefit-Cost Ratio (BCR) greater than 1.0 for each circuit. This allows the analysis to select the alternative that maximizes customer benefits while aligning with system constraints and investment feasibility. The Benefit-Cost Analysis results below are based on the recommended scenario.

As outlined in Section 4.5 above, the benefits were measured in terms of avoided customer outages. To provide a clear representation, results are displayed as a percentile ranking based on the Resilience, Reliability, & Risk Benefit-Cost Ratio (BCR) at the circuit level (highest to lowest). Figure 5-26 illustrates the expected benefits of avoiding customer outages from the Distribution Automation Program. The figure includes each circuit's recommended distribution automation scenario from either the Sectionalization, Automate Existing Ties, or Build New Ties option.

The figure includes the absolute benefit in Customer Minutes Interrupted (CMI) from the decrease in normalized historical outage records, the percentage improvement in CMI, and the circuits where quantified benefits exceed costs. Approximately 29% of the 2,640 circuits have a BCR ≥ 0.9. For these circuits, the evaluation indicates an expected improvement in CMI of approximately 38% ranging from 23% to 47% in the percentile ranking view.

Beyond the circuits with BCR ≥ 0.9, an additional 31% of circuits produce some level of CMI reduction to customers. While these investments are not justified by the quantitative BCA alone, some are likely to prove to be beneficial to customers when also considering the safety benefits and other benefits not quantified within the model. These findings demonstrate strong potential for targeted distribution automation investments to minimize outage impacts and improve reliability for DTE customers.

Figure 5-26: Distribution Automation Program Avoided Customer Outage Benefit



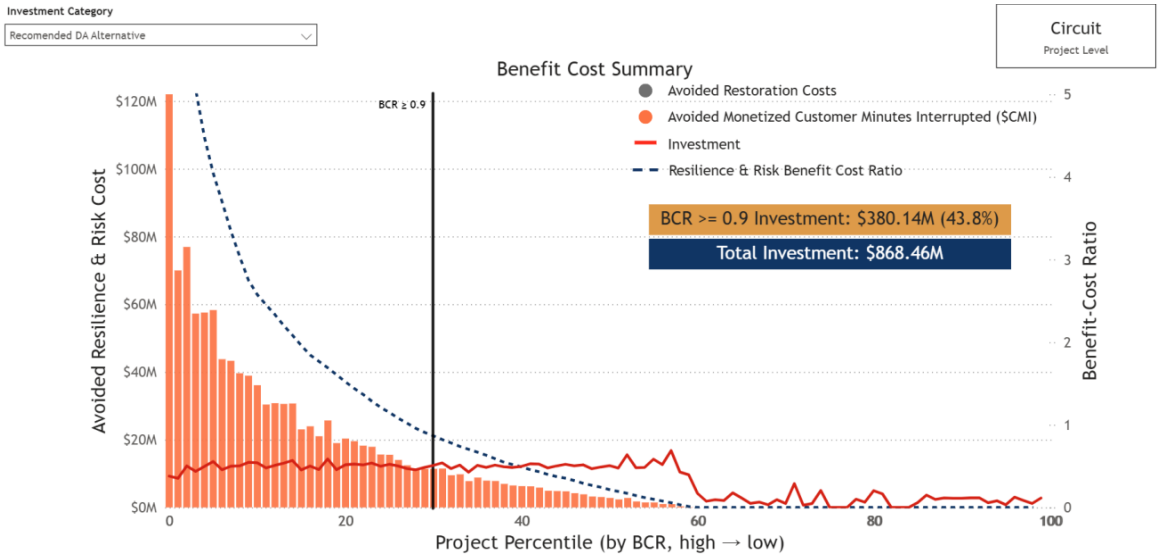
When reviewing Figure 5-26, it is important to note that the modeling approach is fundamentally conservative when calculating CMI improvement. When reviewing the BCR summary, it is important to note that the items listed below demonstrate the conservatism embedded in the approach:

- The model conservatively assumes that the duration of time required for a crew to deal with an outage event (find the outage location, equipment repair, restore power) is the same with or without DA investment. However, with SCADA sectionalizing reclosers, there is likely better visibility into fault locations, which will speed up the time it takes for a crew to find the outage.
- This approach conservatively does not account for the possibility of more severe future outages driven by increasing climate risk or extreme weather events outside the 2021-2025 study period. The quantified benefits may understate future outage risk because they are grounded in historical outage data.
- The value of outages for C&I customers is likely underestimated due to the use of ICE 2.0. Incorporating the most recent ICE Calculator results (which were published after this BCA had been performed), would likely produce greater benefits for these customers. This is described in Section 4.2.
- The BCA does not currently reflect the protection coordination between recloser and downstream fuses that is applied by DTE. DTE implements a fuse saving coordination that allows for the reclosers to clear a momentary fault on the line before a fuse blows open and results in a permanent outage to customers until a crew can replace it. The BCA currently does not reflect fuse saving coordination between protective devices that inherently prevents more sustained outages and is conservative in the benefits modeled.
- The analysis uses a 20-year model length for the discounted cash flow, meaning that an investment in DA is estimated to produce benefits for customers for the next 20 years. This assumption is conservative, as it is likely that the reclosers will last longer than 20 years and continue producing benefits for customers. Benefits after 20 years have not been quantified in the BCA.
- The model assumes that DTE has already made investments in PTMM and Vegetation Management. As a result, the benefits presented reflect the remaining value available to Distribution Automation (DA) after the impacts of those programs have been realized. This is discussed further in Section 4.7.1.

- The quantified benefits do not include reductions in the DTE's reactive costs. The reduction of crew hours spent due to DA's improvement of the restoration process are not quantified. In general, the better visibility and control that SCADA devices provide will likely reduce DTE's reactive costs. Further, reclosers can clear faults through their reclosing action, and as a result crews don't need to deploy to isolate and clear the fault
-

Figure 5-27 takes the CMI benefits from Figure 5-26 and applies the ICE Calculator (see Section 4.2) to monetize the outages and include the expected investment for each circuit to show the BCR. If this program were applied to the entire DTE distribution system, the overall investment level would be approximately $868.46 million. The weighted BCR for this program is 1.37. The figure shows that $380.14 million, or 43.8% of the total investment have a BCR ≥ 0.9. The weighted BCR for deploying this program only on circuits where BCR ≥ 0.9 is 2.71.

Figure 5-27: Distribution Automation Program BCR Summary



5.7.4 Qualitative Benefits and Costs

While the quantified Benefit-Cost Analysis demonstrates benefits to customers, there

are qualitative aspects that the BCA did not capture. Improvements to safety and the restoration process were not captured in the quantitative BCA, but have meaningful impact to both customers and the utility.

The quantified Benefit-Cost evaluation described above only included investments for reliability improvement. As noted above, this program also focuses on deploying reclosers outside of 4.8 kV substations at the station cable pole to minimize the risks of live wire. 1898 & Co. supported DTE in identifying circuits to deploy reclosers on the 4.8 kV system for this purpose. Other parts of DTE's filing include the specific scope and cost of this part of the program. Given the historical frequency of these types of faults that are not identified by the current protection scheme, this investment is justified in mitigating this risk to the general public.

The quantified BCA also does not consider DA's potential to improve the restoration process. DTE's current practice during outage restoration is to restore customers before repairing the failed infrastructure. With distribution automation, the reclosers will perform the outage restoration, rather than crews performing the manual switching. In addition to identifying outages more quickly, crews will save time from performing the manual switching, allowing them to focus more of their time on infrastructure repairs, decreasing outage times. These improvements in crew efficiency are not quantified in the BCA, but they have the potential to reduce outage durations and increase crew availability.

Following equipment repairs, energizing the system is currently done manually by crews. In the case of mainline outages, this requires crews to re-engage the substation breaker to reenergize the circuit. This causes outage times to be higher as the crews need to drive back to the substation. With distribution automation, system re-energizing can be done more quickly. This decrease has not been incorporated into these CMI benefits making the analysis conservative. The impact to the restoration process is especially valuable during major event days and catastrophic events, when crew availability is constrained.

In light of the conservative analysis, the importance of DTE's restoration process, and

the importance of reducing safety risk, investments in distribution automation are well justified.

5.8 Communication Network

This section presents an updated Benefit-Cost Analysis (BCA) of long-term communication network solutions for DTE. The goal is to identify a system-wide "North Star" communications strategy that delivers the greatest value to DTE's customers while supporting the grid's future operational needs and, based on that "North Star", evaluate near-term investments in fiber installation. In 2025, an initial analysis evaluated multiple scenarios for modernizing DTE's grid communications. Since that time, DTE's planning assumptions and strategic objectives have continued to evolve.

This 2026 update focuses on a direct comparison between two primary alternatives: continuing to use Public Cellular networks versus deploying a representative Private Cellular communications solution supported by fiber backhaul. The evaluation covers High, Likely, and Low connected device growth scenarios and excludes Distribution Automation (DA) program benefits in order to isolate communication network-related costs and cost avoidance.

Across all scenarios, the Private Cellular alternative results in lower total life-cycle costs than the Public Cellular approach, yielding a strong positive Benefit-Cost ratio (BCR). This analysis demonstrates that in present value terms, for every $1.00 invested in a Private Cellular network, DTE and its customers avoid roughly $1.56 to $1.61 in costs that would occur under the Public Cellular option. These quantified results reflect typical lifetime cost characteristics of private cellular communications solutions and are complemented by qualitative benefits related to reliability, cybersecurity, and operational flexibility, which are discussed later in this report.

Over a 40-year period, this translates to present-value savings on the order of $3 to $5 billion (depending on future device growth). These savings mainly stem from eliminating recurring carrier fees and avoiding forced mid-life equipment

replacements. They also provide a clear justification for pursuing a Private Cellular network as the "North Star" communications strategy.

5.8.1 Introduction and Background

This section provides an introduction, background, and context for the communication network analysis completed by 1898 & Co.

5.8.1.1 The Need for a Modern Communication Network

A modern, high-capacity, private communication network is essential for DTE to operate the electric grid efficiently, reliably, and securely. Advanced grid devices (smart sensors, automated switches, smart meters, etc.) require real-time connectivity to coordinate actions and improve power delivery. This connectivity enables immediate detection of problems (outages, equipment failures) and supports rapid, remote interventions to maintain service or restore power. It also underpins emerging capabilities like distributed energy resource management and detailed grid analytics.

DTE's current communication network infrastructure includes fiber-optic links and microwave radios on backbone routes, leased circuits in some areas, and TropOS-based wireless mesh networks supporting certain field communications. TropOS-based wireless mesh is effective for backhauling smart meter clusters via cell relays; however, it is not economically scalable for providing direct connectivity to a rapidly growing population of grid-edge devices. As device density increases, deploying dedicated TropOS nodes for each additional asset would result in prohibitive capital and operational costs, limiting its suitability as a long-term solution for expanded grid automation.

In summary, DTE's existing telecom network, while serviceable in the past, is now a bottleneck for grid modernization. Without an upgrade, DTE could face rising costs to keep outdated systems running, and the network would inhibit deployment of new technologies that could improve reliability and efficiency. This situation drives the need to invest in a unified, modern communications platform that can scale with

increasing data demands, connect a growing number of field devices, and meet stricter reliability and security standards – all in a cost-effective manner.

5.8.1.2 Purpose of the BCA and the "North Star" Strategy

The purpose of this BCA is to guide DTE in selecting a long-term, system-wide communication network strategy with the lowest life-cycle cost and greatest strategic value. Rather than focusing on individual projects or regions, this analysis establishes a clear system-wide direction – a "North Star" – for DTE's grid communications. With a defined end-state solution in mind, DTE can evaluate individual incremental investment (e.g., connecting a new substation or replacing a device) to align with the "North Star" plan, avoiding piecemeal fixes that might later become stranded or require rework.

In the 2025 analysis, multiple scenarios were examined including continued reliance on the legacy TropOS system, expanded use of public cellular, and building a private network under various grid use cases. That analysis concluded that the legacy platform was unsustainable and that a new communications strategy was needed for the long-term. It also indicated that building a Private Cellular network, supplemented by fiber, was the most cost-effective path when considering system-wide needs.

This 2026 BCA update builds on those findings with refined assumptions and focus:

- **Direct Comparison – Public vs. Private:** The analysis now centers on a binary choice between Public Cellular and Private Cellular. It eliminates intermediate or hybrid scenarios, providing a clear head-to-head evaluation of the two primary alternatives. Each is assessed over a 40-year horizon to capture the full life-cycle costs including initial capital, ongoing operations, and replacement cycles.
- **Device Growth Scenarios:** To account for uncertainty in the pace of grid modernization, three scenarios are modeled for the total number of connected field devices: High, Likely, and Low. These roughly correspond to reaching ~1.51 million, ~1.31 million, and ~1.07 million devices system-wide,

respectively. This represents a significant expansion from the ~100,000 devices considered in the 2025 analysis. Evaluating this broader range enhances the evaluation to understand if the recommended strategy remains robust whether device deployment accelerates or progresses more gradually in the coming decades.

- **Exclusion of DA Program Benefits:** Unlike the 2025 analysis, the 2026 BCA does not include reliability benefits from the Distribution Automation program in the communication network evaluation. In 2025, certain DA-driven outage reductions were factored into some scenarios. For clarity, the updated BCA treats the communication network purely as an enabling investment and measures its value by comparing costs (i.e., lowest cost and best fit justification method) rather than by assigning it direct reliability benefits. This way, the comparison between Public and Private communication options is straightforward and not conflated with other grid programs.

By taking this approach, the 2026 analysis provides a transparent view of the long-term financial and strategic trade-offs between relying on public carrier networks versus deploying a Private Cellular communications capability. The goal is that DTE's decision is informed by a holistic understanding of the full cost of each option and its alignment with DTE's mission to deliver safe, reliable and affordable energy.

5.8.1.3 Unique Aspects of Telecommunications Investments

Communication networks in a utility context have some unique characteristics that influence how their costs and benefits should be evaluated:

- **Enabling Infrastructure (Indirect Benefits):** A telecom network is an enabling investment. It provides the foundation for other grid projects such as DA, advanced metering, and distributed energy integration, to generate their benefits. It does not directly reduce outages or improve power quality on its own. Therefore, telecom BCAs rely on a "least-cost" (indirect benefit) analysis. We compare alternative ways to provide the required communications service and identify which has the lower 40-year cost. The 'benefit' of the cheaper option is the cost avoided by not choosing the more expensive option. This is

different from other project BCA discussed in this report, where one might quantify direct benefits like fewer outages or operational savings – here, the value is in cost reduction and risk avoidance.

- **Re-Investment Risk – Importance of a Long-Term Plan:** Telecom technologies evolve rapidly. If DTE were to invest in a short-term solution that isn't aligned with the eventual long-term strategy, it might have to replace that solution prematurely, effectively incurring costs twice. For example, expanding the TropOS radio system or signing a short-term cellular contract might seem economical now, but if DTE later commits to a different technology, those expenditures could be wasted. Thus, establishing a long-term preferred solution up front is critical. The 2025 study explored various "end states" to mitigate this risk, and this 2026 analysis reaffirms a clear end-state, such that ongoing investments can build toward a consistent goal.
- **System-Wide vs. Local Optimization:** The chosen system-wide strategy will guide most investments, but DTE acknowledges that local conditions vary. While the Private Cellular with fiber backhaul strategy may be optimal overall, there could be isolated cases, such as a remote location, where a different approach is temporarily more cost-effective. Local deviations can be evaluated on a case-by-case basis, but the overall strategy supports that any exceptions are made consciously and minimally. The BCA's primary role is to set the global optimum; it's understood that localized decisions will be revisited as necessary, especially for unique outliers, all while keeping the "North Star" in view.
- **Sunk Costs in Private Infrastructure:** Investing in a private communications infrastructure involves significant upfront costs that benefit the entire system. For example, core network equipment or a fiber route that connects multiple substations. Once those costs are incurred, they are sunk for the purposes of evaluating incremental decisions. While a localized comparison might show that a single small substation is cheaper to connect via cellular than via fiber, that equation changes if fiber is already running past that site as part of the broader network. In the 2025 analysis, when system-level costs

were allocated down to individual investments, it was clear that after the backbone is built, adding most individual substations to the private network costs very little extra and is financially attractive. Therefore, the system-wide BCA provides the umbrella justification, and localized analyses that consider only incremental costs (not re-counting sunk costs) to decide the best method for each site.

These factors frame the analysis approach (detailed in Section 5.8.4) and the interpretation of results. In essence, two pathways are being compared for critical underlying infrastructure, with an emphasis on which pathway minimizes long-term costs and risks for DTE customers. The communication network value is realized through enabling other functions and this BCA is about achieving that capability in the least-cost way possible.

5.8.2 Solution Alternatives

DTE's communication network decision involves two fundamentally different approaches, each with its own cost and risk profile: continued reliance on Public Cellular networks and deployment of a Private Cellular communications solution with fiber backhaul. Each approach is described in the following sections.

5.8.2.1 Public Cellular Network

The Public Cellular alternative means using commercial wireless carrier networks to meet DTE's grid communication needs. Under this approach, each field device, such as a recloser controller, line sensor, or meter, communicates via a subscription to the carrier's network. DTE would transition devices from legacy systems to cellular communication as those systems age out, leveraging the carriers' existing infrastructure rather than building its own.

Short-Term Pros: By using public networks, DTE can avoid large upfront capital investments in communication infrastructure. Device connectivity can be added on a pay-as-you-go basis: as new devices are deployed or old ones replaced, DTE would equip them with cellular modems and activate service plans. The carriers provide

wide-area coverage and ongoing technology upgrades, which means DTE doesn't have to purchase and install much network equipment itself initially.

Long-Term Cons and Risks: The apparent simplicity and low upfront cost of the public approach come with significant long-term costs and operational risks:

- **Perpetual Carrier Fees:** The Public Cellular model incurs recurring subscription fees for every device, every year. Over a multi-decade period, these fees accumulate to very large totals. They also scale linearly with system growth – if the number of connected devices doubles, the annual fees roughly double. This creates a rising cost curve that never stabilizes, since each new device adds a permanent new expense line.
- **Obsolescence-Driven Replacements:** Perhaps the biggest hidden cost is the impact of carrier technology transitions on device life. Public carriers periodically upgrade their networks (e.g., moving from 4G to 5G) and decommission older technologies. When a carrier shuts down an old network generation, any DTE devices using that technology must be replaced or upgraded to remain operational, even if those devices are only at mid-life. In practical terms, devices that might physically last 15–20 years could require replacement or upgrade in about 10 years due to technology changes. These obsolescence-driven replacements are in addition to the regular end-of-life (EOL) replacements that would occur at the 15–20 year mark; effectively, the Public Cellular strategy can force a doubling of replacement cycles, meaning many devices are bought twice over a 20-year span. This is a major incremental cost and logistical burden that does not exist in a private cellular scenario. The BCA explicitly models these obsolescence cycles as a separate cost category for the public cellular option.
- **External Control and Uncertainty:** By using a public network, DTE gives up a measure of control over a critical operational resource. Service terms, coverage quality, and pricing are determined by the carrier. While DTE can negotiate contracts, it ultimately cannot dictate the carrier's technology roadmap or pricing strategies. This introduces long-term cost uncertainty. For

example, data rates could increase faster than general inflation, or new fee structures might arise. Operationally, during major events, such as storms or emergencies, the carrier's network could be congested with public traffic, potentially compromising the performance of DTE's grid control signals when they are most needed. Additionally, relying on a public network means that cybersecurity controls and responses are partially in the carrier's hands, which can complicate compliance with utility-specific security standards.

In summary, while the Public Cellular alternative provides a near-term, low-capital way to meet communication needs, it carries significant long-term financial costs and operational risks. The cost to "rent" network services from carriers grows continuously with the system and includes hidden costs like technology refreshes. These factors make the public strategy more expensive and less within DTE's control over the long haul.

5.8.2.2 Private Cellular Network with Fiber Backhaul

The Private Cellular alternative reflects deployment of a dedicated cellular communications capability designed to support utility grid operations, with fiber backhaul providing high-capacity connectivity between access sites, substations, and control centers. The analysis evaluates representative infrastructure and operating cost characteristics typical of private cellular solutions, without assuming a specific spectrum band, licensing approach, or ownership model.

Upfront Investments: Unlike the public option, the Private Cellular strategy requires upfront capital investment:

- **Network Infrastructure Build-Out:** The network cost assumptions used in this analysis are intended to be representative of a private cellular deployment suitable for wide-area utility communications, including radio access equipment, core network functionality, and supporting infrastructure. These assumptions are used solely for the purpose of estimating typical lifetime costs and do not reflect a final design decision regarding spectrum selection or network configuration. The model assumes that major capital outlays for the

private network would begin in 2028, with the majority of capital spending complete by 2032.

- **Fiber Backhaul Expansion:** To support a Private Cellular network, fiber-optic cables are crucial for connecting radio towers and substations to the utility's control centers and to each other. DTE plans to expand its fiber network between 2026 and 2032 such that all key sites (including nearly all substations) have a high-capacity, low-latency connection. This fiber network not only carries cellular traffic, but also strengthens the utility's overall communications backbone (e.g., for relaying protection signals or other non-cellular data).
- **Device Equipment Updates:** In preparation for and during the Private Cellular rollout, DTE will replace or retrofit a large number of field devices with cellular-capable communication modules. The migration of devices onto the new network is projected to start in earnest by 2033 (once the infrastructure is ready) and proceed through the 2030s.

Long-Term Cost Structure: After this build-out, the cost profile of the Private Cellular network becomes favorable:

- **Minimal Recurring Costs per Device:** There are no carrier subscription fees for each device. Once the network exists, adding a new device involves only the one-time cost of the device's communications module and a negligible increase in the network's operating expense. In practical terms, the marginal cost of connecting each additional device is very low, since the network can accommodate growth without proportionally increasing cost. This stands in contrast to the Public model, where each device brings a new monthly bill.
- **Controlled Replacement Cycles:** Under a private cellular operating model, technology upgrades can be aligned with DTE's own schedule. Devices can remain in service for their full natural life (often 15–20 years) without being retired early due to network changes. This means the Private Cellular scenario largely avoids the kind of mid-life, obsolescence-driven

replacements for the Public option. In the financial model, no additional 10-year forced replacements were modeled in the Private scenario.

Operational Benefits: Beyond cost, a private network offers control and performance benefits:

- **Dedicated Reliability:** Key sites are equipped with backup power and redundant links, and critical communication paths can be engineered to meet utility reliability standards which are often higher than commercial communication network standards. During grid emergencies, the private network will carry only utility traffic, and it remains available for real-time operations even if public networks are jammed. DTE can also implement quality of service (QoS) settings to ensure that the most critical data, such as protective relay signals, are never delayed or dropped.
- **Security and Compliance:** A Private Cellular network is a closed, private system. DTE can enforce end-to-end encryption, strong authentication, and continuous monitoring tailored to the utility's cyber security requirements. The network can be isolated from public internet access, reducing cyber risk. This approach aligns well with regulatory expectations (e.g., NERC CIP standards) that critical control systems be secure and under the utility's direct oversight. DTE's security team can manage the network's defenses directly, without needing to rely on a third-party provider's policies or incident response.
- **Flexibility and Scalability:** The Private Cellular network can be upgraded or expanded as needed. DTE can increase capacity (through spectrum enhancements or additional sites) if usage grows, and it can incorporate new technologies when they mature and provide clear value. This can be done on DTE's own timetable, balancing cost and benefits. In contrast, under the public approach DTE would be subject to the carrier's upgrade timeline regardless of its own readiness. The ability to scale the private network inexpensively means that as DTE's grid evolves with more

automation, more sensors, and new control schemes, the communication network will not be a limiting factor or a cost-prohibitive hurdle.

Summary of Private Cellular: The Private Cellular option requires upfront planning and capital, but it transitions DTE from paying indefinitely for leased public network services to a dedicated communications platform. Over time, the investment is paid back through avoided fees and greater operational efficiencies. It positions DTE with a communications platform that is resilient, secure, and economically scalable for the foreseeable future.

5.8.3 Benefit-Cost Analysis Methodology

This BCA evaluates the full life-cycle cost of two telecommunications alternatives: Public Cellular and Private Cellular. The analysis calculates the present value of all costs incurred between 2026 and 2072, beginning with the start of capital expenditures for the Private Cellular network. This includes early investments in fiber deployment starting in 2026 and major infrastructure build-out occurring through 2032. The present value of all costs is calculated for each option to determine which is more economical in the long run. All cash flows are discounted to 2026 using a 6.50% discount rate, and an annual cost escalation of 2.50% is assumed for future costs.

The analysis treats the Public Cellular scenario as the baseline. The “benefit” of the Private Cellular scenario is the set of costs avoided by not following the Public Cellular path. This approach frames the decision as a least-cost problem, appropriate for an enabling infrastructure investment. If Private Cellular can provide the required communication service at lower life-cycle cost, then it yields a positive net benefit equal to the avoided costs of the more expensive public option.

5.8.3.1 Analysis Timeline and Comparison Basis

Analysis Period (2026–2072): The model assumes that Private Cellular network construction will take place primarily between 2028 and 2032, with fiber deployment beginning earlier in 2026 and continuing in parallel. By 2033, a substantial portion of spend would have happened and Private Cellular network is expected to be in service

and able to start supporting DTE's field devices. The comparison between Public and Private scenarios is structured to reflect equivalent service delivery between 2033-2072, while still accounting for all relevant costs incurred during the build-out phase (beginning in 2026) in the present value calculations.

Transition Period Considerations: Beginning in 2033, as DTE initiates the migration of existing field devices from Public Cellular to the Private Cellular network, the Private scenario incurs overlapping costs; namely, continued carrier fees for devices not yet transitioned. 1898 & Co. included these overlapping costs in the Private scenario cash flow for a fair comparison.

This approach holds the scope of service constant for each scenario during the comparison period; the variables are how they achieve it and at what cost.

5.8.3.2 Key Cost Components and Assumptions

The BCA model includes several major cost elements. Each one is outlined below:

- **Edge Device Investments and Replacements**: This includes costs for deploying new communication-enabled field devices and replacing them over time.
  - **Device Inventory & Unit Costs:** DTE provided a detailed inventory of existing field devices that rely on communications, with counts by type, and the expected average cost to replace or upgrade each device type.
  - **Natural End-of-Life (EOL) Cycle:** We assume most field devices have a useful life of 20 years. Using device age profiles, 1898 & Co. applied end-of-life curves to model when devices would be retired due to normal aging or wear-out. This spreads replacements over the 40-year span instead of all at once. Under both scenarios, devices would undergo these regular EOL replacements.
  - **Obsolescence-Driven Replacements:** In the Public Cellular scenario, devices face an additional replacement cycle around every 10 years on average, driven purely by carrier technology transitions. For example, the shutdown of 3G or 4G networks forcing upgrades to 4G or 5G.
    These obsolescence-driven replacements are in addition to the 20-year EOL

replacements. The model explicitly includes this by assuming an effective 10-year communication lifespan for devices on the public network. This effectively doubles the number of replacements for each device over 40 years (e.g., a device might be replaced at year 10 due to obsolescence and again at year 20 for true end-of-life). In the Public scenario, to avoid double counting, the model treats obsolescence-driven replacements as incremental to the natural replacement cycle. In the Private Cellular scenario, this incremental obsolescence cost is set to zero, reflecting the assumption that a private cellular network would help avoid premature device retirements. Additionally, in the Private Cellular scenario, 1898 & Co. assumed no forced mid-life replacements. Devices are retired at the end of their natural life, with technology upgrades managed to coincide with those cycles. This key difference eliminates a major cost category in the Private scenario.

- **Carrier Service Fees:** For each device on a public network, DTE must pay ongoing carrier fees (for data plans or connectivity). DTE provided current per-device annual fees for various device types. In our model, these fees are applied to every active device in the Public scenario for each year, growing as the number of devices grows. 1898 & Co. assumed an escalation of 2.5% per year on fee rates (matching general inflation). Carrier fees are a dominant cost in the Public scenario's long-term profile, and they do not decline over time or with scale. More devices always mean proportionally more fees. In the Private Cellular scenario, these fees are almost eliminated after the transition period, since most devices will use the private network. Note that a very small number of specialty connections might still use public networks due to unique circumstances, but these have been assumed to be negligible in cost.
- **Private Cellular Network Infrastructure Costs:** DTE provided an estimate of capital investments for building and expanding the private network:
  - **Spectrum Acquisition and Core Network:** This includes securing suitable spectrum (a dedicated frequency band) and deploying a

dedicated cellular core. These costs occur early (2028–2029) and are necessary for network launch.

- **Fiber Routes and Substation Links:** About 29 main fiber route projects were analyzed to fill additional gaps in the existing fiber network. 1898 & Co. included the costs of constructing these routes (which typically span between clusters of substations) between 2026 and 2032, as well as the costs to install fiber "last-mile" connections and networking gear at each substation. Fiber not only carries cellular traffic but also strengthens DTE's capacity to handle other communications (e.g., protective relaying, high-speed data transfers) independent of third-party telecom providers.
- In the Public Cellular scenario, the primary O&M costs are embedded in the carrier fees (since the carrier operates the network). DTE's internal O&M is minimal beyond managing contracts and perhaps some integration equipment.
- In the Private Cellular scenario, there are O&M costs to run the network – including staffing for network operations, maintenance of tower sites (e.g., inspections, repairs), updating network software, and maintaining the fiber plant. These cost estimates provided by DTE are included in the model and contribute to the annual expenses of the Private scenario.

All cost elements are summed over the 2026–2072 timeline including build-out years and then discounted to 2026 to compare the total present values of each alternative. The difference between them (Public minus Private) represents the net savings or "benefit" of choosing the Private Cellular path. The following section presents the results of this analysis.

5.8.4 System-Wide "North Star" Benefit-Cost Results

To evaluate the long-term financial implications of each communication network strategy, the 2026 BCA assessed the total life-cycle costs of the Public Cellular and Private Cellular over 2026-2072 study period. This analysis provides a comprehensive

view of the cumulative capital, operational, and replacement costs associated with each option, enabling a direct comparison of their economic performance under varying grid modernization scenarios.

5.8.4.1 Total Life-Cycle Costs

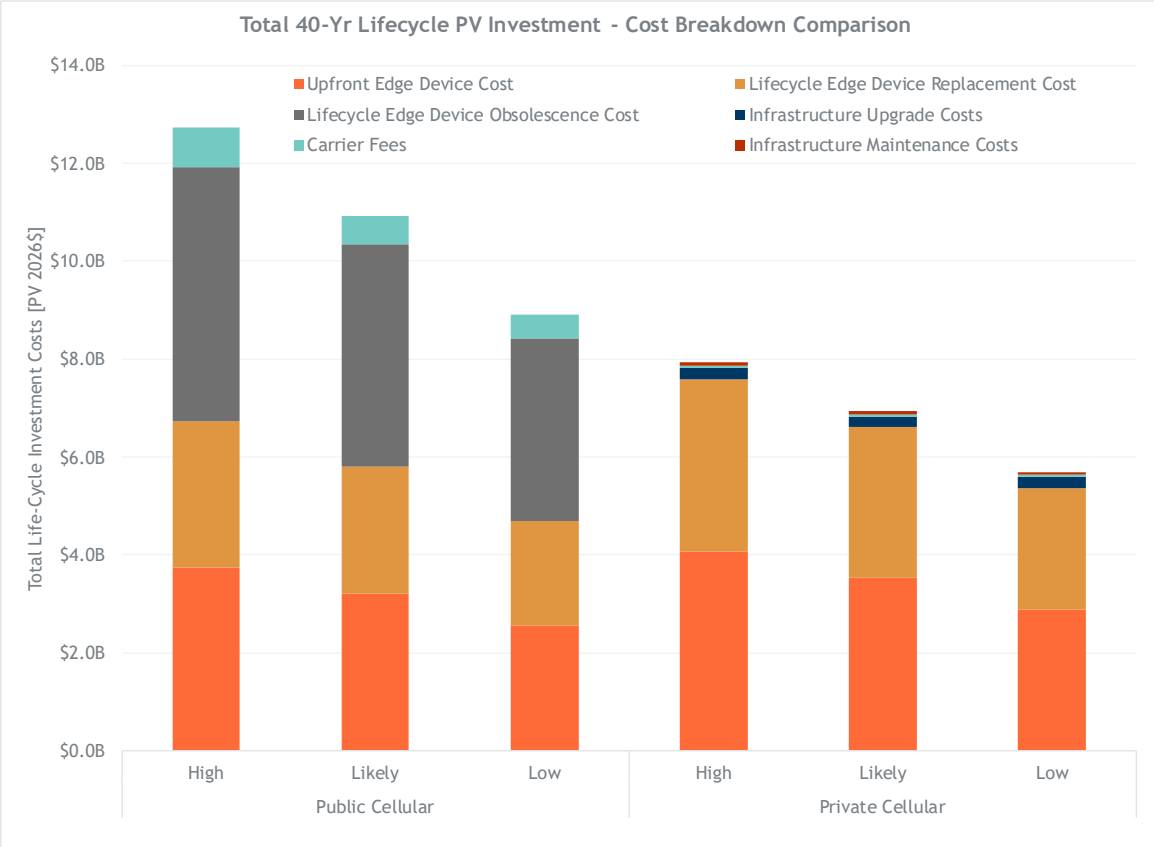
For each device growth scenario (High, Likely, Low), 1898 & Co. calculated the total life-cycle cost of each alternative, in present value terms (2026 dollars):

- **Public Cellular – Total Life-Cycle Cost (Present Value, PV):**
  - High Growth (1.51M devices): $12.73 billion
  - Likely Growth (1.31M devices): $10.92 billion
  - Low Growth (1.07M devices): $8.90 billion
- **Private Cellular – Total Life-Cycle Cost (Present Value, PV):**
  - High Growth (1.51M devices): $7.93 billion
  - Likely Growth (1.31M devices): $6.93 billion
  - Low Growth (1.07M devices): $5.69 billion

In every scenario, the Private Cellular alternative remains significantly lower-cost over the full life cycle. The resulting present-value cost advantage of Private Cellular is approximately $4.8 billion in the High case, $4.0 billion in the Likely case, and $3.2 billion in the Low case.

The cost advantage of Private Cellular is more pronounced at higher device counts. This is because the Public scenario costs, especially carrier fees and obsolescence-driven replacements, scale almost directly with the number of devices. Whereas the Private scenario costs plateau after the initial build-out since additional devices add very little incremental cost. The result is that as the grid becomes more connected, moving from Low to High device growth, the gap between the two scenarios' costs widens in favor of Private Cellular. Figure 5-28 shows the comparison of the public cellular and Private Cellular present values side by side.

Figure 5-28: 40-Year Present Value Cost Breakdown: Public vs. Private (for each scenario)



5.8.4.2 Cost Breakdown and Drivers

To illustrate why the Private Cellular option is cheaper, the life-cycle costs are broken into key components for the Likely scenario (nominally 1.31M devices) in Table 5-1 below. The patterns are similar in High and Low cases.

Table 5-1: Life-Cycle Cost Breakdown (Likely Scenario, PV 2026$)

Cost Category (PV)	Public Cellular (Million)	Private Cellular (Million)
Upfront Device Investments (Initial wave)	$3,200 M	$3,538 M
Lifecycle Device Replacements (EOL)	$2,599 M	$3,067 M
Obsolescence-Driven Replacements	$4,533 M	$0 M
Network Infrastructure Build-Out (Private Cellular)	$0 M	$227 M
Carrier Service Fees (Recurring)	$590 M	$41 M
Network O&M (Infrastructure Ops)	$0 M	$54 M
Total Present Value Cost (2026$)	**$10,922 M**	**$6,927 M**

Summary of this breakdown is outlined below:

- **Obsolescence-Driven Replacements (Public Only):** In the Public Cellular PV total (~$10.9 billion), about $4.5 billion, roughly 40%, is due to obsolescence-driven device replacements. These are the mid-life (≈10-year) replacements required to keep up with carrier changes, incremental over the standard end-of-life replacements. The Private Cellular column shows $0 for this category, highlighting a huge cost avoidance: in the Private case, devices are not replaced in 10 years just for network reasons; they are utilized for their 20-year life.
- **Carrier Fees vs. Network O&M:** The costs in the Private scenario (network O&M of ~$54 million PV and a residual $41 million in carrier fees during the overlap period) are a small fraction of the over half a billion dollars (PV) in carrier fees under the Public scenario. In nominal terms, the Public scenario would involve paying several million dollars every year to carriers, for a total that dwarfs the ongoing cost of a private network.
- **Device Costs:** Both scenarios involve significant investment in field devices over the 40-year study period, including initial deployment and subsequent replacements. The Private Cellular scenario shows a somewhat higher present

value of device costs upfront because it assumes deployment of new cellular-compatible devices, whereas the Public scenario begins with approximately 111k existing devices already in service. The Public scenario can therefore defer a portion of initial replacements relative to Private Cellular. However, once obsolescence-driven replacements are incorporated, the Public scenario ultimately replaces a greater number of devices over time.

- **"Infrastructure" vs. "No Infrastructure":** The Private scenario incurs about $227 million PV in infrastructure costs (towers, fiber, spectrum) that the Public scenario avoids. However, this network infrastructure investment leads to much greater cost avoidance in later years, resulting in a strong net-positive outcome.

5.8.4.3 Benefit-Cost Ratio

Using the totals above, the Benefit-Cost Ratio (BCR) for choosing Private Cellular can be calculated for each scenario. The BCR is the ratio of the avoided cost (Public minus Private) to the Private Cellular investment cost:

- **High scenario**: BCR ≈ 1.61 (Avoided cost $4.80B vs. Private Cellular cost $7.93B)
- **Likely scenario**: BCR ≈ 1.58 (Avoided cost $4.00B vs. Private Cellular cost $6.93B)
- **Low scenario**: BCR ≈ 1.56 (Avoided cost $3.21B vs. Private Cellular cost $5.69B)

All BCRs are above 1.0, indicating a financially favorable investment under a wide range of futures. The Likely case BCR of 1.58 means that in present value terms, the Private Cellular strategy returns about $1.58 in avoided costs for every $1.00 spent. Even in the Low case (slow growth), it's roughly $1.56 back per $1.00 and in the High case it's about $1.61 back per $1.00.

5.8.4.4 Summary of Key Quantitative Insights

The quantitative analysis clearly demonstrates:

- The private cellular scenario is the preferred solution as it is the least-cost alternative for all device count scenarios.
- The larger the scale of the grid communications (more devices/data), the greater the savings with Private Cellular, since the costs do not grow linearly with device count whereas Public costs do.
- A significant portion of the Public scenario cost is attributable to carrier fees and forced early replacements, elements the Private scenario avoids.
- The financial case holds even if grid modernization is slower (Low scenario) or if discount rate or other factors change moderately. For instance, even a scenario with the low device growth still yielded a BCR of 1.56.

The next section examines the economic outcome at a more granular level (individual substation connections and fiber routes), reinforcing that this strategy is sound not just in aggregate but in its implementation details. Qualitative drivers and other strategic considerations area also address below.

5.8.5 Substation & Fiber Route Benefit-Cost Results

To check if the recommended strategy makes sense not only system-wide but also at a granular level, the analysis examined the economics of connecting individual substations and fiber routes under the Private Cellular strategy. DTE's 2026 plan analyzes 29 new fiber route projects to provide connectivity to its 602 distribution substations. These projects supplement those already constructed or currently underway, and some routes will serve multiple substations. Each substation or route can be evaluated with its own BCA, considering the local costs to extend fiber or wireless coverage and the local benefits (primarily avoided carrier fees and avoided legacy system costs for that substation’s devices).

1898 & Co. performed this cost allocation of the global costs to each of the substations and fiber routes for two scenarios to understand the preferred alternative, Private or Public cellular, for each individual component. The first was to

allocate all costs to each substation and fiber route, the second was to exclude 'sunk' costs in the allocation. In the case of this BCA, the sunk costs for cost allocation purposes are the cost of towers and spectrum. It is appropriate to exclude these costs when considered individual investments.

Updated 2026 Substation BCA Results: Even under the more conservative assumptions of the 2026 analysis (with no DA benefits, etc.), most substations are economically justified to connect to the private network. Below is a summary of substation-level BCR (BCR > 1 means Private Cellular solution is lower cost than the Public Cellular alternative) outcomes across the scenarios:

Table 5-2: Substation Benefit-Cost Analysis Summary

Substation BCR	High (602 subs)	Likely (602 subs)	Low (602 subs)
BCR ≥ 0.9	470 substations	458 substations	454 substations
BCR ≥ 0.9 (Sunk Cost Excluded)	497 substations	495 substations	491 substations

In the Likely scenario, 458 out of 602 substations (approximately 75%) show a BCR of 0.9 or higher on an individual basis. This indicates that connecting those substations to the Private Cellular with fiber network yields a positive net financial return over the analysis period when considering their specific costs and avoided costs.

When system-wide sunk costs are excluded, the number of substations meeting this threshold increases to 495 in the Likely scenario, demonstrating that the Private Cellular solution is even more economically favorable when evaluated on an incremental, location-specific basis.

An additional 12 substations fall just below break-even (BCR between 0.8 and 0.9); these are typically locations with higher fiber costs or lower device counts, but they are close to achieving positive economics. A further 36 substations show partial benefits (BCR between 0 and 0.8). The remaining 96 substations were not allocated any communication-dependent benefits in the model due to limited available data. As

a result, neither the Public nor Private scenario was modeled to provide quantifiable benefits at locations and are therefore excluded from the economic comparison.

Updated 2026 Fiber Route BCA Results: The fiber routes are groupings of substation connections (each route ties a set of substations into the network). Evaluating at this aggregate level (which is often how projects would be executed) also shows robust results.

Table 5-3: Fiber Routes Benefit-Cost Analysis Summary

Fiber Route BCR	High (29 routes)	Likely (29 routes)	Low (29 routes)
BCR ≥ 0.9	19 routes	19 routes	18 routes
BCR ≥ 0.9 (Sunk Cost Excluded)	29 routes	28 routes	26 routes

In the Likely scenario, 19 of the 29 fiber route projects have a BCR of 0.9 or higher, indicating strong net economic value. When sunk costs are excluded, nearly all fiber routes exceed the BCR ≥ 0.9 threshold, underscoring that route-level economics improve materially once system-wide investments are removed from individual project evaluations.

The remaining routes all show positive benefits, with 3 routes falling in the 0.8–0.9 BCR range and 7 routes in the 0–0.8 range. No fiber route shows a zero benefit. Every planned route carries some of the communications load and thus provides some avoided cost. The routes with lower BCRs usually serve areas with fewer devices or longer distances, but they often still need to be built for network topology reasons (to reach remote pockets). These lower-return routes are relatively few, with all routes showing some benefits.

Furthermore, these results do not account for strategic value of network redundancy or future use on those routes. They strictly look at currently anticipated device-driven benefits, making them conservative.

From a system planning perspective, the updated analysis confirms that DTE's planned fiber build-out and substation connections under the Private Cellular strategy remain economically sound:

- A substantial percentage of the total substation investment, by number of sites, is either breakeven or net positive, with results strengthening further when system-wide sunk costs are excluded.
- All 29 fiber routes provide value, and about two-thirds of them in the Likely case have clear net benefits (BCR ≥ 0.9). The remaining routes still contribute to the overall strategy (for completeness of the network) and have partial cost recovery through avoided expenses. When system-wide sunk costs are excluded, nearly all fiber routes exceed the BCR ≥ 0.9 threshold, indicating even stronger route-level economics.

It's also worth noting that these results are slightly conservative. They do not include potential operational benefits of having fiber at every substation, such as improved protection schemes or future applications, and they assume no DA reliability benefits. If even a small fraction of the qualitative benefits (e.g., faster restoration in storm events due to more reliable comms) were monetized, many of the borderline cases would likely tip to BCR ≥ 0.9. However, even without those considerations, the local-level economics are strong.

The 2026 substation and fiber route analysis reinforces that the Private Cellular/fiber strategy is not only optimal for the system but also justified when drilling down to individual projects. Each project is either clearly beneficial or strategically necessary as part of the broader network roll-out. This local perspective provides additional assurance that the chosen path will create value for customers at every level of implementation.

In conclusion, transitioning to a Private Cellular/fiber communication network is the recommended long-term strategy for DTE and its customers. It provides the lowest life-cycle cost solution, avoids the pitfalls of vendor dependency and forced upgrades, and establishes a robust foundation for the grid's ongoing modernization.

5.8.6 Qualitative Benefits and Strategic Considerations

While the numbers make a strong case for the Private Cellular strategy, there are additional qualitative benefits that bolster it as the prudent long-term choice for DTE:

- **Reliability and Resilience:** With a private network, DTE can design its communication network to utility-grade reliability standards. This includes robust backup power at communication sites, redundant paths (e.g., fiber loops) for critical links, and coverage focused on grid asset locations (not population centers). During major storms or emergencies, when public cellular networks often experience congestion or outages, the private network would continue to function solely for DTE's operations. This dedicated capacity means, for example, that automated restoration commands and damage assessment data can flow unimpeded even if cellular phone service for the public is overloaded. The result is faster outage response and a more robust grid during crises. These reliability improvements, while not explicitly monetized in the BCA, are invaluable in fulfilling DTE's service obligations.
- **Cybersecurity and Compliance:** With a private, closed network, DTE significantly reduces cybersecurity risks. Communications with substations and field devices can be kept off the public internet and confined to DTE-controlled infrastructure. This 'air gap' and control over network access make it much harder for malicious actors to infiltrate or disrupt critical systems. Public carrier networks, in contrast, connect millions of users and rely on broadly shared infrastructure and protocols, creating a larger attack surface and potential vulnerabilities outside of DTE's direct control. A private network aligns with regulatory trends (e.g., NERC CIP standards) that favor isolating key grid control systems on secure, utility-run circuits. Adopting Private Cellular now anticipates future compliance requirements and avoids the risk that DTE would be forced for security reasons to migrate off public networks later (at possibly great expense).

- **Cost Predictability and Control:** The Private Cellular model converts variable costs into fixed costs. This contrasts with the Public model, where costs remain variable (per device) and subject to market forces. Utilities and regulators generally prefer cost stability. Through a private cellular deployment supported through long-term arrangements, DTE avoids the risk of sudden carrier fee increases or changes in terms of carrier fees. Any technological upgrades on the private network can be planned and budgeted internally, rather than reacting to an external mandate (which might come at an inconvenient time financially). This control also means DTE can improve the timing of investments – for example, deciding to implement a 5G upgrade when equipment costs have come down and a genuine need exists, rather than when a carrier decides to pursue it for competitive consumer reasons.
- **Scalability and Future Innovation:** The analysis showed that as device counts go up, the private network's relative advantage grows. This implies that the more DTE modernizes and digitizes its grid, the more value a private network provides. Importantly, a private network enables future use cases at low marginal cost. If DTE in 10 years wants to add thousands of distributed energy resource controllers or support a network of EV charging stations with grid management signals, or deploy advanced sensors on every transformer, the communications cost to do so on the Private Cellular would be minimal. That encourages innovation and adoption of beneficial technologies. In the Public scenario, each new use case would come with a hefty new communications bill (potentially tipping some projects from feasible to infeasible due to ongoing costs). Thus, choosing Private Cellular not only saves money on current forecasts, but removes a potential barrier to future grid innovations – it's an investment in optionality. The communication network capacity can be seen as an abundant resource that DTE owns, ready to be used in whatever way it provides value to customers, without needing a business case for each MB of data.

Beyond the clear numerical savings, the Private Cellular network is a strategic enabler. It provides DTE with a higher reliability communications backbone, better

security postures, stable and lower long-term costs, and the flexibility to support the grid's evolution. These benefits are difficult to quantify but have profound implications for the success of DTE's grid modernization and the quality of service experienced by customers.

5.9 Subtransmission Redesign and Rebuild

1898 & Co. performed a Benefit-Cost Analysis of the subtransmission projects provided by DTE using the Resiliency Model and Equipment Failure Mitigation Model methodology outlined in Section 4.3 and Section 4.4. The evaluation quantified the reliability, resilience, and risk-reduction benefits of replacing and reconfiguring aging subtransmission infrastructure. Assets associated with these projects were evaluated separately and were not included in the analyses for the other evaluated programs.

5.9.1 Background & Program Description

The subtransmission system serves as a critical link between the transmission and distribution networks. Subtransmission circuits deliver power from the bulk electric system to distribution substations that serve customers throughout the DTE service territory. Because these circuits supply multiple substations and distribution feeders, failures on subtransmission infrastructure can impact large portions of the electric system.

Several areas of the DTE subtransmission system include infrastructure that is approaching or exceeding its expected service life. Aging conductors, poles, and station equipment increase the likelihood of failures that can result in outages and complex restoration efforts. Additionally, some portions of the system are experiencing capacity constraints or operational limitations that restrict maintenance activities or limit the ability to transfer load during outages.

The Subtransmission Redesign and Rebuild Program addresses these challenges by modernizing portions of the subtransmission network. Projects within this program typically include reconductoring existing lines, replacing aging structures, upgrading station equipment, installing switching devices, and improving circuit configurations to enhance system performance.

Several projects also improve accessibility and maintainability by relocating circuits from deep right-of-way to more accessible corridors. These improvements reduce exposure to vegetation-related outages and enhance a crew's ability to perform maintenance and restoration activities.

5.9.2 Estimating Investment Activities and Cost

This section outlines the systematic approach 1898 & Co. employed to identify the investment activities associated with the Subtransmission Redesign and Rebuild Program and estimate their expected costs.

DTE provided a list of projects for evaluation as part of the Benefit-Cost Analysis. In total, 12 projects were provided for evaluation in the Subtransmission Redesign and Rebuild Program. Each project was provided in a project-level scoping document containing detailed information regarding the proposed work. This information included the circuits or substations where the work would occur, the quantities of infrastructure to be replaced, retired, or installed, and the estimated cost of each project.

1898 & Co. reviewed the scoping information provided by DTE and developed a process to translate the proposed project scopes into asset-level investment activities that could be evaluated within the Benefit-Cost modeling framework.

Using the circuits, substations, and equipment descriptions included in the project scopes, 1898 & Co. applied a set of rules to identify the specific assets associated with each project. These rules mapped project-scope information to assets in DTE's GIS and Maximo asset management system.

Where project scopes included quantities such as miles of conductor replacement or counts of equipment replacement, these quantities were used to identify the specific assets included in the evaluation. By identifying assets at this level of granularity, the evaluation improves the relationship between the infrastructure being replaced, the likelihood of equipment failures, and the customers impacted by those failures.

The expected cost of each project was based on the project-level cost estimates provided by DTE as part of the project scoping documentation. DTE also provided unit

cost assumptions, which were incorporated into the modeling of investment activities to estimate the risk and resilience benefits associated with the projects.

For purposes of the Benefit-Cost Analysis, DTE's total project costs were compared with the quantified risk and resilience benefits associated with replacing or reconfiguring the infrastructure.

5.9.3 Quantitative Benefit-Cost Results

1898 & Co. evaluated the benefits of the Subtransmission Redesign and Rebuild Program using the analytics models described in Section 4.3 and 4.4. The evaluation quantified the reliability, resilience, and risk reduction benefits associated with replacing aging subtransmission infrastructure.

Subtransmission assets serve as critical backbone infrastructure for the electric system. Failures on these assets can interrupt service to multiple downstream substations and distribution circuits. Proactively replacing aging infrastructure reduces the likelihood of these failures and the associated customer outages.

The analysis estimated avoided restoration costs and reductions in Customer Minutes Interrupted (CMI) associated with lowering the probability of equipment failures. The avoided outage impacts were monetized using the ICE Calculator described in Section 4.2. In addition to avoided outage costs, the evaluation incorporated avoided restoration costs associated with repair activities following equipment failures.

Table 5-5 includes a high-level description of each project, the resulting Resilience, Reliability, & Risk BCR, and the primary benefit drivers associated with the investment. Using the legend in Table 5-4, the table identifies whether each project's benefits are associated with avoided restoration costs, avoided customer minutes interrupted (CMI), capacity, operability, and safety. This summary provides additional context for understanding how the quantified BCA results align with the underlying drivers for each project. The evaluated projects represent a total investment of approximately $405 million. These results indicate that several projects deliver strong, quantified reliability and resilience benefits relative to their investment costs. Other projects produce more modest quantified benefits but may still provide

important improvements in system reliability, operations, and safety that are not fully captured in the quantitative evaluation.

Table 5-4: Benefit Drivers

Driver	Indicator
Avoided Restoration Costs	■
Avoided Customer Outages (CMI)	■
Capacity	■
Operability	■
Safety	■

Table 5-5: Subtransmission Redesign and Rebuild Projects Description and Drivers

Project Name	Project Description	BCR	Benefit Drivers (Monetized and Captured by BCR)	Benefit Drivers (Non-monetized)
Subtransmission Redesign & Rebuild: Waterman	Bus consolidation project at Waterman Substation consisting of: • Remove 15 breakers • Remove 11 relay panels • Replace 5 breakers • Replace 1 relay panel • Remove 5 reactors • Replace approximately 1,500 feet of subtransmission cable	1.43	■	■
Subtransmission Redesign & Rebuild: Tie 7504	• Replace 12.2 miles of Subtransmission overhead conductor on Tie 7504 • Install 4 miles of new Subtransmission overhead conductor on Tie 7504 to reroute out of deep right of way • Replace 3 pole top switches • Install 1 40kV capacitor bank at Wilmont substation • Replace 1 breaker, 2 disconnects, 1 relay panel at Wilmont Substation • Replace 1 breaker, 2 disconnects, 1 relay panel at Arrowhead Substation	0.94	■ ■	■ ■ ■
Subtransmission Redesign & Rebuild: Tie 3205	• Replace 1 breaker, 2 disconnects, 1 relay panel at Port Austin • Install 28.8 miles of overhead conductor on Tie 3205 and relocate circuit out of	0.62	■ ■	■ ■

	deep right of way • Remove 25.6 miles of overhead conductor on Tie 3205 • Install 6 pole top switches • Remove 8 pole top switches			
Subtransmission Redesign & Rebuild: Tie 4104	• Replace 18 miles of overhead conductor on Tie 4104 • Install 4 miles of new subtransmission overhead conductor on Tie 4104 to reroute out of deep right of way • Replace 18 miles of distribution under-build conductor and associated equipment • Install 2 Automatic Pole Top Switches • Replace 3 manual pole top switches • Install 1 circuit switcher and replace control house and relaying at Talbot substation	0.59		
Subtransmission Redesign & Rebuild: Trunk 2455	• Install 1000 feet of conduit and 4 manholes • Remove 200 feet of conduit • Install 14,000 feet of subtransmission cable • Install 4,000 feet of distribution cable • Remove 7,700 feet of subtransmission cable • Remove 2,200 feet of distribution cable	0.53		
Subtransmission Redesign & Rebuild: Pigeon Area Improvement	• Install (1) new station and decommission and remove existing station equipment on existing substation property • Decommission and remove existing station equipment at (1) existing station • Replace (2) breakers • Reconfigure (5) subtransmission tie lines	0.52		
Subtransmission Redesign & Rebuild: Trunk 7386	• Replace 2 miles of cable on Trunk 7386 • Install .5 miles of conduit • Reconductor ~1 mile of 3/0 ACSR with new 40kV 636 AL SW-ACSR • Remove pothead and install new cable terminations at Chestnut Station • Replace one cable pole and cable termination	0.44		
Subtransmission Redesign & Rebuild: Imlay Rebuild	• Purchase substation property • Build (1) new class B substation on new property, substation to be named Borland. • Reconfigure subtransmission lines, install 1 mile of conduit, new cable poles, and 3.5 miles of 40kV overhead • Convert subtransmission exists at Otsego from overhead to underground • Decommission class B substation at Imlay • Upgrade relaying at Hunter's Creek and Yale substation	0.32		
Subtransmission Redesign &	Reconfigure Cortland substation:	0.22		

Rebuild: Cortland Station Expansion	• ITC will relocate 120kV equipment to across the street property • Replace 2 station transformers • Install 6 circuit switchers • Replace 600 feet of cable, install 600 ft of conduit			
Subtransmission Redesign & Rebuild: Transformer High Side Protection Program	• Install high side switching devices, circuit switches or breakers on 22 subtransmission and distribution transformers at 16 different stations • Replace or relocate ten of those transformers due to space constraints	0.22		
Subtransmission Redesign & Rebuild: Hurst	Expansion at Hurst substation to consist of: • Install 1 station transformer • Install 1 circuit switcher • Install 1 breaker • Install 1 disconnect • Install 1 relay panel	N/A		
Subtransmission Redesign & Rebuild: Trunk 4601	Expansion at Benet substation to consist of: • Install 1 station bus • Install 3 breakers • Install 6 station disconnects • Install 4 relay panels Extension of Trunk 4601 line to consist of: • Install 11.1 mile of overhead construction	N/A		

Note: Certain projects primarily involve installing new infrastructure. Because the quantitative BCA is designed to evaluate the benefits of replacing or retiring existing at-risk assets, monetized benefits were not captured for these projects. These investments may still provide important capacity and operability benefits.

5.9.4 Qualitative Additional Benefits of the Program

The previous sections have outlined the results from quantifying the benefits of specific investments. As discussed above in Section 4.6, it is difficult to fully capture and quantify all the factors that go into every investment decision. For the Subtransmission Redesign and Rebuild Program, several additional qualitative benefits further support the proposed investments.

First, these projects improve the operational flexibility of the electric system. Upgrading aging infrastructure and modernizing subtransmission configurations improve system operators' ability to isolate faults, transfer load between substations, and perform maintenance activities without significantly impacting customers. In several areas of the system, existing infrastructure limits the ability to perform

maintenance or operational switching due to legacy equipment or constrained system configurations. Modernizing these facilities improves system operability and reduces the operational risks associated with maintaining the electric system.

Second, replacing aging subtransmission infrastructure improves safety for both utility personnel and the public. Aging conductors, poles, breakers, and station equipment can pose safety risks when failures occur unexpectedly. Proactively replacing this infrastructure reduces the likelihood of catastrophic equipment failures and improves the safety of field crews who maintain and operate the system.

Finally, the subtransmission network is a critical component in providing service to DTE customers. When an outage occurs on the subtransmission system, it could affect thousands of DTE customers; for this reason, the system is designed to provide N-1 redundancy to reduce impacts. DTE has a duty to serve customers safely and reliably, and these investments support long-term system planning objectives by increasing system capacity and strengthening the backbone of the electric grid. Modernized subtransmission infrastructure enhances the system's ability to accommodate load growth and distributed energy resources (DERs) and provides redundancy to reduce the impact of service disruption to customers.

While the quantitative analysis demonstrates that many of these investments provide measurable reliability and resilience benefits to customers, the additional qualitative benefits described above further support the value of the Subtransmission Redesign and Rebuild Program.

5.10 4.8 kV & 8.3 kV Conversion

1898 & Co. performed a Benefit-Cost Analysis of the conversion projects provided by DTE using the Resiliency Model and Equipment Failure Mitigation Model methodology outlined in Section 4.3 and Section 4.4 above. The evaluation quantified the reliability, resilience, and risk reduction benefits associated with converting legacy voltage circuits and replacing aging infrastructure. Assets associated with these projects were evaluated separately and were not included in the analyses for the other evaluated programs.

5.10.1 Background & Program Description

The DTE Electric distribution system includes several areas that continue to operate at legacy voltage levels, including 4.8 kV and 8.3 kV systems. Much of this infrastructure was constructed several decades ago and includes equipment that is approaching the end of its service life.

Lower-voltage distribution systems generally have lower capacity and less operational flexibility than higher-voltage distribution systems. In addition, many of these legacy systems operate as electrical islands with limited ability to transfer load to neighboring circuits. These operational constraints can make it more difficult to perform maintenance activities, restore service during outage events, and accommodate increasing customer demand.

Several of the projects included in this program address aging substations and distribution and subtransmission infrastructure that are approaching or exceeding their expected service life. In some cases, substations serving these systems were constructed many decades ago and contain equipment for which replacement parts are increasingly difficult to obtain. Other projects address capacity constraints associated with growing customer demand.

The 4.8 kV and 8.3 kV Conversion Programs address these challenges by modernizing portions of the distribution network and converting legacy systems to 13.2 kV operation. These projects may include constructing new substations, expanding or upgrading existing substations, converting overhead and underground circuits to higher voltage levels, consolidating circuits to a single substation, replacing aging transformers and cables, and installing modern switching and automation equipment.

By converting these legacy systems to higher-voltage distribution configurations, the program improves circuit capacity, enhances operational flexibility, and supports the long-term reliability and resilience of the electric distribution system.

5.10.2 Estimating Investment Activities and Cost

The process used to identify investment activities and estimate costs for the voltage conversion projects follows the same methodology described above for the Subtransmission Redesign and Rebuild Program.

DTE provided project-level scoping documentation describing the circuits involved, the quantities of infrastructure to be converted, replaced, or retired, and the estimated project costs. These scopes were reviewed by 1898 & Co. and translated into asset-level investment activities using the GIS and Maximo datasets provided by DTE.

Assets associated with each project were identified based on the circuits, substations, and equipment types described in the project scope. Where project scopes specified quantities such as miles of conductor replacement or counts of equipment replacement, these quantities were used to determine the specific assets included in the evaluation.

The expected cost of each project was based on the project-level cost estimates provided by DTE as part of the project scoping documentation. DTE also provided unit cost assumptions, which were incorporated into the modeling of investment activities to estimate the reliability and resilience benefits associated with the projects.

For purposes of the Benefit-Cost Analysis, DTE's total project costs were compared with the quantified reliability and resilience benefits associated with replacing or upgrading the infrastructure.

5.10.3 Quantitative Benefit-Cost Results

1898 & Co. evaluated the benefits of the 4.8 kV and 8.3 kV Conversion Programs using the analytics models described in Section 4.3 and 4.4. The evaluation quantified the expected reduction in equipment failure risk associated with replacing or retiring aging infrastructure and converting legacy voltage circuits.

By replacing aging infrastructure, increasing circuit operating voltage, and installing sectionalizing and automation devices, the program reduces the likelihood of equipment failures and improves circuit performance. These improvements reduce

the frequency and duration of customer outages and can also reduce outage duration by improving fault isolation, enabling load transfers, and supporting more efficient service restoration.

The analysis estimated avoided customer interruptions and reductions in CMI associated with the proposed investments. The avoided outage impacts were monetized using the ICE Calculator described in Section 4.2. In addition to avoided outage costs, the evaluation incorporated avoided restoration costs associated with emergency repairs following equipment failures.

Table 5-7 includes a high-level description of each project, the resulting Resilience, Reliability, & Risk BCR, and the primary benefit drivers associated with the investment. Using the legend in Table 5-6, Table 5-7 identifies whether each project's benefits are associated with avoided restoration costs, avoided customer minutes interrupted (CMI), capacity, operability, and safety. This summary provides additional context for understanding how the quantified BCA results align with the underlying drivers for each project. The evaluated projects represent a total investment of approximately $2.9 billion. These results indicate that a majority of the projects deliver strong, quantified reliability and resilience benefits relative to their investment costs. Other projects produce more modest quantified benefits but may still provide important improvements in system reliability, operations, capacity, and safety that are not fully captured in the quantitative evaluation.

Table 5-6: Benefit Drivers

Driver	Indicator
Avoided Restoration Costs	■
Avoided Customer Outages (CMI)	■
Capacity	■
Operability	■
Safety	■

Table 5-7: 4.8 kV & 8.3 kV Conversion and CODI Project Descriptions and Drivers

Project Name	Project Description	BCR	Benefit Drivers (Monetized and Captured by BCR)	Benefit Drivers (Non-monetized)
CODI: Kent/Gibson Conversion - Kent Decommissioning	• Consolidate, pre-convert & convert (6) KENT4.8kV circuits to CORKT13.2kV • Consolidate, pre-convert & convert (8) GIBSN 4.8kV circuits to CORKT13.2kV • Consolidate, pre-convert & convert (2) SCOTN 4.8kV circuits to CORKT13.2kV • Consolidate, pre-convert & convert (3) HOWRD 4.8kV circuits to CORKT13.2kV • Convert (17) primary customer from 4.8 kV to 13.2 kV • Decommission 8 miles of 4.8 kV cable • Remove (8) 4.8 kV breakers and decommission Kent substation • Remove (11) 4.8 kV breakers and decommission Gibson substation • Decommission 16 miles of 24kV cables and equipment	2.51		
8.3 kV CC: Pontiac Overhead Conversion	• Purchase property. • Extend (1.4 miles) conduit. • Extend (14 miles) cable. • Replace (33.4 miles) overhead. • Rebuild 120-13.2kV Wheeler substation. • Convert (33.4 miles) to 13.2kV • Decommission five substations – Bartlett, Paddock, Stockwell, Rapid Street, Bloomfield.	2.3		
4.8 kV CC: Zenon Substation and Circuit Conversion	• Establish (6) new ZENON 13.2kV circuits from existing 13.2kV power delivery center and convert 4.8kV power delivery center at ZENON • Pre-convert & convert 144 miles of 4.8kV overhead to 13.2kV • Install 3 miles of conduit • Install 17 miles of system cable • Convert or ISO down (70) primary service customers • Replace two transformers at ZENON substation • Install a third 24/32/40 MVA	2.28		

	transformer at ZENON substation • Install third transformer, second PDC, and third cap bank at Corktown substation • Decommission SCOTN substation and 24kV trunk lines • Decommission WSEND substation and 24kV trunk lines			
4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade)	• Construct a new 120-13.2kV substation named Promenade • Install new conduit and manholes for new circuits • Install new cable for new circuits • Convert existing 4.8kV circuits and transfer to new 13.2kV circuits (over 100 miles of overhead) • Decommission existing system cable • Decommission Pulford, Lynch, and Lambert substations • Decommission eight 24kV trunk lines	2.15		
4.8 kV CC: Calla Circuit Conversion and Phase 2	• Build (1/5) mile of overhead to establish new backbone connection • Rebuild, pre-convert and convert approximately 11 miles of overhead conductor to 13.2kV • Remove (1/2) mile of overhead infrastructure and install (3/4) mile of new overhead infrastructure in road right-of-way • Establish jumpering points and load relief to adjacent DIMND circuit	1.61		
CODI: Howard Conversion	• Install (41) new netbank transformers • Decommission (6) network feeders and their substation positions/breakers • Decommission (9) feeder section switches • Replace or remove 38 netbank transformers and structures • Install (4) 3-way 600A feeder section switches and (8) 2-way 200A feeder section switches • Install (9) 3-way manholes and (1) 2-way manhole • Construct over 14,400 feet of conduit • Construct ~43,560' of new AC	1.5		

	network system cable • Decommission (16) 4.8 kV power lines • Decommission (16) breakers and positions • Decommission (27) miles of 4.8 kV cable • Rebuild (12) miles of radial power line system cable • Convert (26) primary customers to 13.2 kV • Convert and consolidate the circuits to 13.2 kV fed by Corktown, Temple, St. Antoine, and Cat substations • Decommission (5) 24 kV Cable Lines - TRK 787T-B, TRK 709T-B, TRK 753T-B, TRK 764T-B, TRK 775T-E • Decommission Howard Substation			
4.8 kV CC: Ann Arbor AC Network Conversion	• Pre-convert all Hoover circuits • Convert and Transfer Hoover Circuits to neighboring substations • Upgrade Hoover Substation from 40-4.8kV to 40-13.2kV Substation • Build and commission new 40-13.2kV Class A substation with 5 load carrying circuits	1.31		
4.8 kV CC: Belleville Substation and Circuit Conversion	• Pre-convert all Belleville 4.8kV circuits • Upgrade Belleville 13.2kV Substation from Class 'T' to a Class 'R' • Commission a second 13.2kV Belleville circuit • Convert and transfer all Belleville 4.8kV circuits	1.3		
4.8 kV CC: Grosse Pointe South Substation and Circuit Conversion	• Procure substation property • Build new Class A 120/13.2 kV substation named Conner • Convert and consolidate VERNR and WAYBN circuits (273 overhead 4.8kV miles) • Install 3000 ft of conduit and 6000 ft of cable • Decommission WAYBN and DENVR substations	1.27		
CODI: Garfield Network Upgrade	• Convert and consolidate circuits fed by Stone Pool, Midtown, Alfred, Detroit substations • Decommission (4) 24 kV lines -	1.24		

	TRK1809 , TRK1815, TRK 1820 & TRK1834 • Decommission Garfield Substation			
4.8 kV CC: Hilton Substation and Circuit Conversion	• Expand Hilton Road Substation so that it has 3 transformers and 2 PDCs • Convert 100% of circuits from FERND, HAZPK, and WDSID substations and transfer to Hilton Road Substation • Decommission FERND, HAZPK, and WDSID substations	1.15		
4.8 kV CC: Pittsfield Substation and Circuit Conversion	• Reconductor (26.9) miles of overhead conductor • Replace (272) overhead transformers • Replace (225) underground transformers • Install (2.9) miles of cable • Install (0.9) miles of conduit • Commission (1) new 40-13.2kV substation and (4) new load-carrying circuits • Decommission (1) 40-4.8kV substation and (.5) mile of system cable	0.83		
4.8 kV CC: Hawthorne Relief and Circuit Conversion	• Purchase property for substation • Expand Mallard substation • Convert and/or consolidate (15) circuits • Decommission Daly substation	0.71		
8.3 kV CC: Pontiac Underground Conversion	• Pre-convert (5) circuits	0.69		
4.8 kV CC: Hemlock Decommissioning and Circuit Conversion	• Replace (30) miles of overhead conductor • Pre-convert and convert 4.8kV area to 13.2kV • Decommission (1) 40-4.8kV substation and remove (1/2) mile of system cable • Install (1) new 40-13.2kV substation, install 2 miles of system conduit, and 3 miles of system cable • Commission 4 new distribution circuits and 1 throwover circuit	0.57		
4.8 kV CC: White Lake Decommissioning and Circuit Conversion	• Installing (1) 40-13.2kV substation, substation to be named Meadowlake • Installing (2) miles of system conduit • Installing (4) miles of system	0.53		

	cable • Convert area to 13.2kV • Decommission 40-4.8kV White Lake substation			
4.8 kV CC: Barber Substation and Circuit Conversion	• Purchase 1 new parcel of property • Install 1 new substation, to be named Ten Mile • Install 7300 ft of conduit for the new TENMI circuits • Convert 53.4 miles of overhead 4.8kV conductor • Decommission Bunert substation	0.43		
4.8 kV CC: New Baltimore	• Purchase substation property • Build new class A substation at New Baltimore • Decommission Class R and Class E substations at New Baltimore	0.40		
4.8 kV CC: Rochester Decommissioning and Tienken Relief	• Acquiring property • Installing (1) 120-13.2kV substation, substation name not identified yet. • Installing (3) miles of system conduit • Installing (16) miles of system cable • Removing (1.46) miles of system cable • Converting area to 13.2kV • Building (0.1) miles of overhead conductor • Installing (10) pole top switches • Installing (18) viper reclosers • Decommissioning Tienken40-13.2kV substation	0.28		

5.10.4 Qualitative Additional Benefits of the Program

The previous sections have outlined the results from quantifying the benefits of specific investments. As discussed above in Section 4.6, it is difficult to fully capture and quantify all the factors that go into every investment decision. For the 4.8 kV and 8.3 kV Conversion Programs, several additional qualitative benefits further support the proposed investments.

First, these projects improve the safety of the electric distribution system. Many of the existing 4.8 kV and 8.3 kV systems include aging infrastructure and legacy

equipment that are increasingly difficult to maintain and repair. For portions of the legacy 4.8 kV delta system, downed conductors may remain energized, creating an elevated public safety risk. In addition, portions of the 8.3 kV system include aging underground cable and vault infrastructure that can increase the complexity and risk associated with inspection, maintenance, and restoration work. Converting these systems to modern distribution voltage standards reduces the likelihood of equipment failures and helps mitigate safety risks associated with aging assets and wire-down events.

Second, the program simplifies system operations and maintenance. Legacy voltage systems often require specialized equipment and operating practices. Converting these systems to a higher voltage standard allows DTE to standardize equipment and operating practices across the system, improving operational efficiency and reducing long-term maintenance challenges.

Third, these projects improve the distribution system's ability to accommodate future load growth and electrification. Higher-voltage distribution systems offer greater capacity and improved voltage performance than legacy systems. These improvements help the electric system support future economic development and evolving customer energy needs.

Finally, many projects in this program enable the retirement of aging substations and infrastructure approaching the end of their useful life. Replacing these facilities with modern infrastructure improves the overall reliability and resilience of the electric distribution system. DTE has a duty to serve customers safely and reliably, and these investments support long-term system planning objectives by increasing system capacity and strengthening the backbone of the electric grid.

While the quantitative analysis demonstrates measurable risk and resilience benefits associated with these investments, the qualitative benefits described above further support the value of the 4.8 kV and 8.3 kV Conversion Program.

1898 & CO

PART OF BURNS & McDONNELL

1898andco.com

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-22046
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS

AND

REVISED DIRECT TESTIMONY

OF

QUINN GERDES

DTE ELECTRIC COMPANY
QUALIFICATIONS AND REVISED DIRECT TESTIMONY OF QUINN GERDES

Line No.

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

A1. My name is Quinn Gerdes (he/him/his). My business address is One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Energy Corporate Services, LLC, a subsidiary of DTE Energy Company (DTE Energy), as a Senior Strategist, Regulatory Affairs.

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of DTE Electric Company (DTE Electric or Company).

Q3. What is your educational background?

A3. I received a Bachelor of Arts in Applied Mathematics from the University of Illinois Urbana Champaign.

Q4. What is your work experience?

A4. In 2020, I was employed by Accenture, LLC as a Management Consultant in their Utilities practice. In this role, I supported and advised investor-owned utilities with the execution of IT infrastructure implementations and developing market strategies for new energy technologies like renewable based hydrogen. Additionally, I supported State Energy Offices with grant writing and the development of low-income electrification programs. In 2024, I began my employment with DTE Energy as a Senior Strategist in Regulatory Affairs.

Q5. What are your current duties and responsibilities?

Line No.

A5. My responsibilities include the development of forecast allocation schedules as well as supporting activities related to the execution of DTE Electric's rate strategy.

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

A6. Yes. I have previously sponsored testimony in:

- U-21860 DTE Electric 2025 Rate Case

Purpose of Testimony

Q7. What is the purpose of your testimony in this proceeding?

A7. The purpose of my testimony is to present the Forecast Allocation Schedules supporting the Company's proposed cost-of-service analysis in this case, present the Allocation Schedules supporting the Large Load Studies, and address additional analyses and outreach requirements for customers that have since transitioned from Rate Schedule D1.6 to Rate Schedule D1.11.

- **Forecast Allocation Schedules:** Support the allocation schedules and methodology utilized by the Company for the 12-month period ending February 29, 2028.
- **Large Load Study Allocation Schedules:** Support the allocation schedules used by the Company to conduct the six large load cost-of-service and rate design-studies pursuant to the Commission's directive in Case No. U-21990.
- **D1.6 Analysis:** Share the results of the Company's review of research on the factors affecting low-income customers' ability to shift usage.
- **D1.6 AMI-Based Outreach:** Describe the Company's Advanced Metering Infrastructure AMI-based outreach for customers who formerly took service under Rate Schedule D1.6.

Line No.

1 **Q8. Are you sponsoring any exhibits in this proceeding?**

2 A8. Yes. I support the following exhibits:

Exhibit	Schedule	Description
A-5	E2	Cost of Service Allocation Methodology Diagram
A-5	E3	Allocation Schedule Description
A-17	G1.1	Forecast Energy Allocation Schedules – 12 months ending February 29, 2028
A-17	G1.2	Demand and Energy Allocation Percentages by Rate Class
A-36	AA7	Forecast Energy Allocation Schedules – 1st Large Load Study
A-36	AA8	Demand and Energy Allocation Percentages by Rate Class – 1st Large Load Study
A-37	AB7	Forecast Energy Allocation Schedules – 2nd Large Load Study
A-37	AB8	Demand and Energy Allocation Percentages by Rate Class – 2nd Large Load Study
A-38	AC7	Forecast Energy Allocation Schedules – 3rd Large Load Study
A-38	AC8	Demand and Energy Allocation Percentages by Rate Class – 3rd Large Load Study
A-39	AD7	Forecast Energy Allocation Schedules – 4th Large Load Study
A-39	AD8 Revised	Demand and Energy Allocation Percentages by Rate Class – 4th Large Load Study

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A-40	AE7	Forecast Energy Allocation Schedules – 5th Large Load Study
A-40	AE8	Demand and Energy Allocation Percentages by Rate Class – 5th Large Load Study
A-41	AF7	Forecast Energy Allocation Schedules – 6th Large Load Study
A-41	AF8	Demand and Energy Allocation Percentages by Rate Class – 6th Large Load Study
A-43	AG1	AMI-based communication developed for D1.6 customers

Q9. Were these exhibits prepared by you or under your direction?

A9. Yes, they were.

<u>Forecast Allocation Schedules</u>

Q10. Are there any technical terms used in your allocations testimony that may require explanation?

A10. Yes. To aid in understanding and to avoid confusion, I am defining the following terms that I use throughout my testimony:

- Customer Class or Class of Service: A set of customers with similar characteristics who have been grouped for the purpose of setting an applicable rate for electric service.
- Total System Analysis (TSA): The study of all customer classes that identifies the hourly demand values for all hours of the year. This is the foundation of allocation schedules.

Line No.

- Energy: The total kilowatt-hours (kWh) or megawatt-hours (MWh) supplied to or used by an individual customer or customer class.
- Demand: The rate at which electric energy is used at a given instant or averaged over a designated time interval. Typically, demand is expressed in kilowatts (kW) or megawatts (MW).
- Service Area System Peak Demand: The highest hourly demand for all customers (full service and electric choice) served on the DTE Electric distribution system within a specific period (day, month, year, etc.). Service Area System Peak Demand is commonly referred to as the 'system peak.'
- Bundled Peak Demand: The highest hourly demand for all full-service customers served by DTE Electric's production system within a specific period (day, month, year, etc.). Bundled Peak Demand is commonly referred to as 'bundled peak.'
- Coincident Peak Demand (CP): The demand of any customer class within a specific period (day, month, year, etc.) that occurs at the same time as the system peak or the bundled peak demand for the same period.
- 12CP: The demand value derived by averaging the actual demand values registered on the monthly system bundled peak hours for January through December for each customer class.
- 4CP: The demand value derived by averaging the actual demand values registered on the monthly bundled peak hours for June through September for each customer class.
- Non-Coincident Peak Demand: The maximum demand of any customer class within a specific period but not necessarily occurring at the time of the system peak demand for that period.

Line No.

- Losses: A term used to define the difference between the electrical energy delivered to a customer (or a given point on the electrical distribution system) and the amount of electrical energy that must be generated at the power plant to serve that customer. In other words, losses refer to the difference in the amount of power generated from the power plant and the point of delivery.
- Load Factor: The ratio, in percent, of the total energy over a designated period of time to the maximum hourly demand (bundled or system) occurring in that period. Load factor is calculated by the formula:

  LF (%) = (Total Energy / (Peak Demand * No. of Hours)) * 100
- Customer-Owned: Industrial customers that use customer-owned substations.
- DTE-Owned: Industrial customers that use DTE Electric single customer or joint-use general distribution substations.
- Transmission Voltage Level: Served directly from the transmission system at 120 kV or above, or from the transmission system through a DTE-owned substation dedicated or primarily providing service to the customer and located on or immediately adjacent to the customer's premises.
- Sub-transmission Voltage Level: Served directly from the sub-transmission system at voltages from 24 kV to 41.6 kV or from the sub-transmission system through a DTE-owned substation dedicated or primarily providing service to the customer and located on or immediately adjacent to the customer's premises.
- Primary Voltage Level: Served directly from the primary distribution system at a nominal voltage between 4.8 kV and 13.2 kV who does not

Line No.

qualify as either a transmission voltage customer or a sub-transmission voltage customer.

- Secondary Service: Served directly from the secondary distribution system at a nominal voltage less than or equal to 4.8 kV and who does not qualify as either a transmission voltage customer, sub-transmission voltage customer or a primary voltage customer.

Q11. What are the data sources for the allocation schedules?

A11. The forecasted test year allocation schedules are based on 2025 customer class sales data obtained from the 2025 Total System Analysis (TSA). The forecast allocation schedules are based on the energy sales forecast for the residential, commercial, and industrial classes supported by Witness Leuker. Additionally, the street lighting and traffic signals sales forecast is supported by Witness Hartley, and the forecast billing determinants supported in my exhibits. These sales levels are shown with losses on Exhibit A-17, Schedule G1.1.

Q12. What is the purpose of the allocation schedules you have developed?

A12. The allocation schedules are developed using customer class sales, data from Advanced Metering Infrastructure (AMI), and quantitative methods to determine the extent (expressed as a percentage) of each customer class's use of the various portions of the electrical system. In this case, the customer class usage percentages determined in the allocation schedules are one of the inputs used by Witness Cejas Goyanes to determine customer class cost responsibility.

Line No.

1 Since not all customer classes utilize the full distribution system to take delivery of
2 electrical service, the allocation schedules are developed to assign only the portions
3 of the system used by each customer class. Exhibit A-5, Schedule E2, includes a
4 diagram which reflects the applicability of allocation schedules to customer class.
5
6 **Q13. How did you develop the allocation schedules?**
7 A13. I developed 13 forecast allocation schedules for use in cost-of-service studies as
8 described in Exhibit A-5, Schedule E3. Each schedule was designed to allocate
9 costs based on each customer class's utilization of a particular part of the electrical
10 system, which is the industry standard practice for developing allocation schedules.
11
12 Schedule 100, shown in Exhibit A-17, Schedule G1.2, is based on the class's
13 forecasted energy consumption. The remaining 12 allocation schedules described
14 in Exhibit A-5, Schedule E3, are based on the forecasted demand that each customer
15 class places on the various portions of the electrical system. The allocation
16 schedule numbers and the associated portion of the electrical system they represent
17 are shown schematically in Exhibit A-5, Schedule E2.
18
19 **Q14. Why does the measurement basis differ for each allocation schedule?**
20 A14. The measurement basis for each allocation schedule is based on the design and
21 service requirements for each portion of the electrical system. Specifically,
22 forecasted energy is used for Power Plant Energy Production (Schedule 100) to
23 serve customers. As customers use energy, they create a demand (rate at which
24 energy is used and/or delivered) on the system.

Line No.

1 The output capacity of Power Plant Production is designed considering the peak
2 demand requirements of the production system, measured as the bundled peak
3 demand. Production Schedule 200A is measured based on forecasted bundled 12
4 CP, while Schedule 200B is measured based on the forecasted bundled 4CP.
5 Schedule 201 – Input to Transmission Substation – is based on the forecasted 12CP
6 of the of the Service Area.
7
8 Schedules 202A, 202B, 202C, 203A, 203B, 203C, 204, and 205 refer to substations,
9 high voltage lines, and transformers, which are designed to carry the maximum load
10 required by the customer classes they serve, regardless of whether the class
11 maximum demand occurs at the same time or a different time as the system peak.
12 The forecasted non-coincident peak and individual customer maximum peak
13 demand are the measurement bases for these allocation schedules.
14
15 Low voltage secondary lines are designed to serve the absolute maximum demand
16 level of the customers they feed. Therefore, Schedule 300 is based on the forecasted
17 sum of the individual customer maximum demands.
18
19 **Q15. How was the 2025 TSA used to develop the demand values determined for the**
20 **forecast allocation schedules?**
21 A15. The basis for the forecast allocation schedules developed for this instant case are
22 the forecasted net sales values presented in Witness Leuker's Exhibit A-15,
23 Schedule E1. However, because Witness Leuker's system peak demand forecast
24 does not include the associated customer class level demand values necessary for
25 allocation schedule development, it was necessary to develop these corresponding

Line No.

demand values by customer class. This was achieved by applying historical load factors to the forecast energy values using industry standard load research principles to derive demand values using energy and load factor. Therefore, forecast demands were calculated by dividing the net forecast energy values (without losses) by the product of the historic load factor and annual hours.

Q16. How were the appropriate historic load factors determined?

A16. A 5-year average load factor was derived from years 2021-2025 and used for each cost-of-service class.

Q17. Why is using the 5-year average historical load factor a better representation of the class's performance than the actual 2025 historic load factor?

A17. Using the 5-year average load factor accounts for any abnormalities in any single year and smooths out any variability due to weather or other anomalies such as economic conditions.

Q18. Why is using average historical load factors a reasonable method of determining forecast demand values?

A18. Using average historical load factors is a reasonable method for determining load factors because there is a mathematical relationship between energy, load factor, and demand. Forecasting demand is necessarily a function of forecasted sales and forecasted load factors. Utilizing load factors to forecast demand values maintains the relationship between energy and demand.

Line No.

1 **Q19. How did you develop the forecast allocation schedules?**

2 A19. I applied the 5-year average load factors to the forecasted energy sales received
3 from Witness Leuker. This method produced the forecast schedules for the period
4 from March 2027 to February 2028, as shown in Exhibit A-17, Schedule G1.1.

5

6 **Q20. How are line losses used in forecast allocation schedules?**

7 A20. Line loss factors are used as a multiplier in allocation schedules to increase the
8 energy or demand value for a given schedule to reflect the amount of production
9 needed to serve the customer class. Line losses were measured by voltage level,
10 allowing allocation schedules to accurately reflect demands on the system caused
11 by different classes of customers.

12

13 **Q21. Are the allocation schedules defined in your testimony developed using**
14 **established principles and methods?**

15 A21. Yes. I used the industry recognized and accepted load research principles. The
16 methods used are consistent with those used by the Company in all its electric
17 general rate cases filed since 2014.

18

19 **Large Load Studies**

20 **Q22. What is the basis for the allocation schedules prepared for the six (6) large load**
21 **studies required by the Order issued in Case No. U-21990?**

22 A22. I used the Company's allocation schedules developed for Case No. U-21860 as a
23 basis for the six studies, pursuant to the Commission's direction to use "DTE
24 Electric's current COSS from its most recent rate case order".[1]

[1] Case No. U-21990 Order dated December 18, 2025, p. 39

Line No.

1 The forecast energy, a direct input to allocations, was updated to match the MPSC
2 Staff's (Staff) adjustments made to the final ordered rate design model.[2] This was
3 done to ensure consistency such that allocations, cost of service, and rate design
4 had the same sales assumptions as a starting point for the large load studies.
5
6 **Q23. What assumptions did you use for the large load study forecasted sales and**
7 **demand?**
8 A23. I used the assumptions supported in the direct testimony of Witness Foley for Large
9 Load Customer 1 and Large Load Customer 2 as a direct input to the allocation
10 schedules.
11
12 **Q24. Please explain each of the six allocation schedules provided.**
13 A24. The large load studies use the allocation schedules used in Case No. U-21860 with
14 the noted change and include the following additional adjustments:
15 • In study 1 the large loads associated with Customer 1 and Customer 2 are
16 included in the D11 and Other allocation class;
17 • In study 2 they are included in a separate cost-of-service class named the
18 Large Load class;
19 • In study 3 the allocation schedules are the same as study 2. The assignment
20 of costs occurs in the cost-of-service models sponsored by Witness Cejas-
21 Goyanes;
22 • In study 4 the allocation schedules use the adjusted Case No. U-21860
23 schedules to be consistent with Staff approved sales in the final rate design
24 model;

[2] The adjustment accounted for the Commission Order related to unregistered meters

Line No.

- In study 5 the allocation schedules are the same as study 2. The direct assignment of costs occurs in the cost-of-service models sponsored by Witness Cejas-Goyanes;
- In study 6 Customer 1 and Customer 2 are each assigned to their own allocation class.

Q25. Were the schedules developed consistent with existing and approved rate case methodologies?

A25. Yes. I prepared these consistently with how the Company has prepared allocation schedules in all its general electric rate cases since 2014.

<u>Rate Schedule D1.6 Analysis</u>

Q26. What additional analysis did the Commission direct the Company to conduct?

A26. In its February 19, 2026, Order in Case No. U-21860 on pages 458 and 459, the Commission required the Company to

1. "include in its next rate case an updated analysis specifically designed to analyze the factors impacting low income customers' ability to shift usage between on peak and off peak;"
2. "as well as an updated shutoff analysis;"
3. "update its current educational outreach to include substantive information about weatherization and smart meters;"
4. "use AMI-based analytics to flag at-risk households;"
5. "deploy targeted, multilingual outreach;" and
6. "and streamline enrollment in assistance."

Line No.

1 **Q27. Which of these requirements do you support in your testimony?**

2 A27. I support requirements one, three and four. Witness Sparks supports requirements
3 two, five and six.

4

5 **Q28. Has this topic been considered in previous proceedings?**

6 A28. Yes. The Company originally proposed the Rate Schedule D1.6 to Rate Schedule
7 D1.11 transition in Case No. U-21297, with subsequent proposals and analyses
8 provided in Case Nos. U-21534 and U-21860. The actual transition of customers
9 from D1.6 to D1.11 occurred in October 2025.

10

11 **Q29. What analyses did the Company undertake during its broader customer**
12 **transition to Rate Schedule D1.11 (Residential Time-of-Use)?**

13 A29. The Company conducted a large pilot and research effort, the Advanced Customer
14 Pricing Pilot (ACPP), which measured participants' willingness and ability to shift
15 usage and the magnitude of that shift. It also tested two Time-of-Use (TOU) pricing
16 configurations. The results of the ACPP were used to support the design of TOU
17 Rate Schedule D1.11 and inform customer communications. The Company
18 completed the transition of approximately 1.9 million residential customers from
19 the Residential Service Rate – Rate Schedule D1 to the Residential Service Rate –
20 Standard TOU – Rate Schedule D1.11 in 2023.

21

22 **Q30. Was that transition limited to non-low-income customers?**

23 A30. No. The Company transitioned all Rate Schedule D1 customers, except those with
24 a non-transmitting meter, to Rate Schedule D1.11. In 2023, the Company estimated
25 that at least 95,000 of those customers transitioned were low-income.

Line No.

1 **Q31. What similarities are there between Rate Schedule D1.6 and D1?**

2 A31. Rate Schedule D1.6 was initially established as the vehicle for delivering the Low
3 Income Assistance (LIA) credit and, by design, mirrored the then-default
4 residential rate (D1). Its structure was not uniquely tailored for low-income
5 customers beyond inclusion of the LIA credit. From a rate design perspective, the
6 D1.6 to D1.11 transition was analogous to the broader D1 to D1.11 transition.[3]

7

8 **Q32. Has the Company considered recreating the ACPP experimental analysis?**

9 A32. Yes, the Company has considered recreating the ACPP control and test conditions,
10 but it is not feasible now that virtually all residential customers have already
11 transitioned to D1.11. There is no longer a contemporaneous control group on
12 which to base an experimental design**.** Additionally, as stated by Witness Sparks in
13 his direct testimony, there are other data limitations that make it challenging to
14 assess a customer's ability to shift usage, separate from their willingness or
15 behavioral response, and he recommended any analyses be led by the Energy
16 Affordability and Assistance Collaborative (EAAC) or other appropriate MPSC
17 workgroup or collaborative process.

18

19 However, I conducted a review of studies that analyzed low-income customers
20 behavioral, structural or technological barriers to load shifting, or evaluated impacts
21 of TOU or dynamic pricing structures on low-income participants.

22

23 **Q33. What factors impacting low-income customers' ability to shift usage did you**
24 **identify in the literature review?**

[3] D1.6 customers transitioned to D1.11 saw no interruption of their receipt of the LIA credit.

Line No.

1 A33. Five categories were identified:

2 1. Health and thermal comfort constraints such as not having direct control over
3 heating and cooling settings or having a medical condition that necessitates
4 specific heating and cooling settings;
5 2. Information and Digital Access limitations such as technology literacy or
6 multilingual needs that can inhibit understanding of load shifting options;
7 3. Rigid work schedules, childcare and elderly care duties limiting the time
8 periods that appliances can be used;
9 4. Housing type and physical attributes such as less energy efficient dwellings,
10 which can reduce the potential load shifting possible; and
11 5. Lack of control technology (e.g. smart thermostats).
12
13 These factors frame ability (what is physically/structurally possible) as distinct
14 from willingness (behaviors/preferences), and they are consistent with the evidence
15 base summarized in the footnotes. [4,5]
16
17 **Q34. What does the literature you reviewed indicate about low-income**
18 **responsiveness to TOU rates?**
19 A34. Multiple studies conclude that low-income customers respond to TOU rates, though
20 the magnitude of potential load shifting varies and often reflects customers' pre-

[4] "Low Income Energy Affordability: Conclusions from a Literature Review by Oak Ridge National Laboratory" accessed at https://info.ornl.gov/sites/publications/Files/Pub124723.pdf on March 9th, 2026.
[5] "2020 ACEEE Summer Study Assessing Equity in TOU: How Low-Income Customers Fare on Time of Use Rates" accessed at 2020_ACEEE-Summer-Study_Assessing-Equity-How-Low-Income-Customers-Fare-on-TOU_Rates_Folks.pdf on March 8th, 2026

Line No.

existing, flatter usage profiles. Importantly, those flatter profiles can mean many low-income customers realize bill benefits without any behavioral changes.[6,7]

Q35. What conclusions did the literature you reviewed draw about the benefits low-income customers see from TOU?

A35. Low-income customers were found to more likely already benefit from TOU rates without enacting any behavioral changes.[6]

For example, Pacific Gas and Electric (PG&E) estimated in its TOU pilot that 75% of low-income customers would benefit from TOU rates. After implementation of the pilot, they found that 90% of transitioned low-income customers benefited from bill savings.

Q36. How do the conclusions of the various studies you reviewed correspond to the analysis DTE Electric has previously presented?

A36. The findings align with the initial impact study the Company performed that found, "[a]ll else being equal, 58% of customers in the analysis would see a lower bill on D1.11."[8] This corroborates the conclusion that many LIA customers will see benefits without any behavioral changes.

[6] "IEE The Impact of Dynamic Pricing on Low Income Customers" accessed at iee_lowincomedynamicpricing_0910.pdf on March 9th, 2026
[7] "Six unique load shapes: A segmentation analysis of Illinois residential electricity consumers" accessed at https://www.citizensutilityboard.org/wp-content/uploads/2019/06/ClusterAnalysisFinal.pdf on March 9th, 2026.
[8] Case No. U-21534 Order dated January 23, 2025, p 391

Line No.

1 **D1.6 AMI-Based Outreach**

2 **Q37. What did the Commission direct the Company to do regarding AMI-based**
3 **outreach to former D1.6 customers?**

4 A37. On page 394 of the January 2025 order in Case No. U-21534, the Commission
5 required the Company to undertake:

6 "expanded educational outreach to low-income customers
7 regarding low-income energy efficiency programs,
8 weatherization, and smart thermostats; and the use of smart
9 meter data to identify customers and address energy-limiting
10 behavior that is adverse to health and safety."

11

12 The Commission further directed the Company on Page 459 in the February 2026
13 order in Case No. U-21860 to "update its current educational outreach to include
14 substantive information about weatherization and smart meters."

15

16 **Q38. What is the Company's outreach plan to address this requirement?**

17 A38. The Company intends to send AMI-based education and outreach materials to
18 customers once in Summer of 2026, and again in early 2027, reaching each
19 customer twice. The communication materials will include:

20 • A customer-specific comparison of current AMI usage to historical
21 patterns;
22 • A usage insight highlighting the customer's highest hour of use;
23 • Targeted messages addressing energy-limiting behavior and promoting the
24 Company's smart thermostat, weatherization and bill assistance programs,
25 with links to multilingual materials.

Line No.

1 Draft communications are provided in Exhibit A-43 Schedule AG-1; discussion of
2 multilingual materials is sponsored by Witness Sparks.
3
4 **Q39. Did the Company evaluate other methods of AMI-based outreach?**
5 A39. Yes. I evaluated the feasibility of measuring energy-limiting behavior using the
6 Energy Equity Gap (EEG) measure described in the 2022 study "Unveiling hidden
7 energy poverty using the energy equity gap."[9] In this paper, researchers used a
8 nonlinear regression model to create a quadratic relationship between electricity
9 consumption and temperature data. They calculate the median inflection
10 temperature (the minima of each quadratic) for each income group and calculate
11 the EEG as the difference between the highest and lowest income group. I was
12 unable to reproduce the results for the former Rate Schedule D1.6 population with
13 an R-Squared greater than .5. I also found that when I did not force a quadratic fit
14 to a customer's temperature and usage data, the model did not select a quadratic
15 equation for any customer.
16
17 Further investigation into the measurement of energy-limiting behaviors or related
18 metrics should be standardized across Michigan – these are questions that apply to
19 all utility providers and are not unique to the Company. As such, the Company
20 recommends that future discussions and research into similar metrics should be
21 conducted in the Commission's Energy Efficiency Advisory Council (EAAC)
22 workgroup, or another similar forum where there is a specific focus on such topics.
23 This would have the dual benefit of bringing the conversation to a broader group

[9] Cong S, Nock D, Qiu YL, Xing B. Unveiling hidden energy poverty using the energy equity gap. Nat Commun. 2022 May 4;13(1):2456. doi: 10.1038/s41467-022-30146-5.

Line No.

with more statewide perspective than a single electric rate case can provide, while also helping manage the record in this and future general rate cases.

Q40. Does this conclude your testimony?

A40. Yes.

Michigan Public Service Commission
DTE Electric Company
Demand and Energy Allocation
Percentages By Rate Class
4th Large Load Study Forecast Power Supply
Power Plant Energy Production
Allocation Schedule 100 - Total Energy

Case No.: U-22046
Exhibit: Revised A-39
Schedule: Revised AD8
Witness: Q. Gerdes

Line No.	(a) Rate Description	(b) COS Class	(c) 4th Large Load Study Total Energy Schedule 100 Allocation Factors
1	Residential		
2	Residential	D1.11 & Other	0.38317
3	Time-of-Day	D1.2	0.00951
4	Space Heating	D2	0.00729
5	Residential O.P.L.	E1/E2/D9	0.00015
6	**Total Residential**		0.40012
7			
8	Secondary		
9	General Service	D3 & Other	0.20531
10	Large General Service	D4	0.04556
11	Schools - Secondary	D3.2	0.00852
12	Commercial O.P.L	E1/E2/D9	0.00070
13	Traffic and Signal Lights	E1/E2/D9	0.00155
14	**Total Secondary**		0.26164
15			
16	Primary		
17	Primary Supply	D11 & Other	0.29202
18	Schools - Primary	D6.2	0.01782
19	Interruptible Primary Supply	D8	0.01397
20	Combined Alt. Metal Mltg. and Process Heat	R1.1/R1.2	0.01128
21	Interruptible Rider	R10	-
22	**Total Primary**		0.33508
23			
24	Street Lighting	E1/E2/D9	0.00316
25			
26	TOTAL		1.00000

Michigan Public Service Commission
DTE Electric Company
Demand and Energy Allocation
Percentages By Rate Class
4th Large Load Study Forecast Power Supply
Production System Output
Allocation Schedule 200A - 12CP

Case No.: U-22046
Exhibit: Revised A-39
Schedule: Revised AD8
Witness: Q. Gerdes

Line No.	(a) Rate Description	(b) COS Class	(c) 4th Large Load Study 12CP Demand Schedule 200A Allocation Factors
1	Residential		
2	Residential	D1.11 & Other	0.43600
3	Time-of-Day	D1.2	0.00883
4	Space Heating	D2	0.00750
5	Residential O.P.L.	E1/E2/D9	0.00010
6	**Total Residential**		0.45243
7			
8	Secondary		
9	General Service	D3 & Other	0.20580
10	Large General Service	D4	0.04127
11	Schools - Secondary	D3.2	0.00832
12	Commercial O.P.L	E1/E2/D9	0.00049
13	Traffic and Signal Lights	E1/E2/D9	0.00108
14	**Total Secondary**		0.25695
15			
16	Primary		
17	Primary Supply	D11 & Other	0.23015
18	Schools - Primary	D6.2	0.01649
19	Interruptible Primary Supply	D8	0.01153
20	Combined Alt. Metal Mltg. and Process Heat	R1.1/R1.2	0.01016
21	Interruptible Rider	R10	0.02008
22	**Total Primary**		0.28842
23			
24	Street Lighting	E1/E2/D9	0.00220
25			
26	TOTAL		1.00000

Michigan Public Service Commission
DTE Electric Company
Demand and Energy Allocation
Percentages By Rate Class
4th Large Load Study Forecast Power Supply
Production System Output
Allocation Schedule 200B - 4CP

Case No.: U-22046
Exhibit: Revised A-39
Schedule: Revised AD8
Witness: Q. Gerdes

	(a)	(b)	(c)
Line No.	**Rate Description**	**COS Class**	**4th Large Load Study 4CP Demand Schedule 200B Allocation Factors**
1	Residential		
2	Residential	D1.11 & Other	0.50227
3	Time-of-Day	D1.2	0.00800
4	Space Heating	D2	0.00523
5	Residential O.P.L.	E1/E2/D9	0.00000
6	**Total Residential**		0.51550
7			
8	Secondary		
9	General Service	D3 & Other	0.20599
10	Large General Service	D4	0.03974
11	Schools - Secondary	D3.2	0.00794
12	Commercial O.P.L	E1/E2/D9	0.00000
13	Traffic and Signal Lights	E1/E2/D9	0.00088
14	**Total Secondary**		0.25455
15			
16	Primary		
17	Primary Supply	D11 & Other	0.20284
18	Schools - Primary	D6.2	0.01751
19	Interruptible Primary Supply	D8	0.00585
20	Combined Alt. Metal Mltg. and Process Heat	R1.1/R1.2	0.00375
21	Interruptible Rider	R10	0.00000
22	**Total Primary**		0.22994
23			
24	Street Lighting	E1/E2/D9	0.00000
25			
26	TOTAL		1.00000

Michigan Public Service Commission
DTE Electric Company
Demand and Energy Allocation
Percentages By Rate Class
4th Large Load Study Forecast Power Suppl
Input to Transmission Substation
Allocation Schedule 201 - 12CP

Case No.: U-22046
Exhibit: Revised A-39
Schedule: Revised AD8
Witness: Q. Gerdes

Line No.	(a) Rate Description	(b) COS Class	(c) 4th Large Load Study 12CP Demand Schedule 201 Allocation Factors
1	Residential		
2	Residential	Residential Secondary	0.45860
3	Residential O.P.L.	E1/E2/D9	0.00006
4	**Total Residential**		0.45866
5			
6	Secondary		
7	General Service	Commercial Secondary	0.28555
8	Commercial O.P.L	E1/E2/D9	0.00028
9	Traffic and Signal Lights	E1/E2/D9	0.00110
10	**Total Secondary**		0.28693
11			
12	Primary		
13	Primary Distribution	Primary	0.21316
14	Subtransmission	Subtransmission	0.03991
15	Transmission	Transmission	-
16	**Total Primary**		0.25307
17			
18	Street Lighting	E1/E2/D9	0.00135
19			
20	TOTAL		1.00000

Michigan Public Service Commission
DTE Electric Company
Demand and Energy Allocation
Percentages By Rate Class
4th Large Load Study Forecast Power Suppl
Input to Subtransmission Lines
Allocation Schedule 202A

Case No.: U-22046
Exhibit: Revised A-39
Schedule: Revised AD8
Witness: Q. Gerdes

	(a)	(b)	(c)
Line No.	**Rate Description**	**COS Class**	**4th Large Load Study Demand Schedule 202A Allocation Factors**
1	Residential		
2	Residential	Residential Secondary	0.53754
3	Residential O.P.L.	E1/E2/D9	0.00027
4	**Total Residential**		0.53781
5			
6	Secondary		
7	General Service	Commercial Secondary	0.26819
8	Commercial O.P.L	E1/E2/D9	0.00101
9	Traffic and Signal Lights	E1/E2/D9	0.00069
10	**Total Secondary**		0.26990
11			
12	Primary		
13	Primary Distribution	Primary	0.18873
14	Subtransmission	Subtransmission	-
15	Transmission	Transmission	-
16	**Total Primary**		0.18873
17			
18	Street Lighting	E1/E2/D9	0.00357
19			
20	TOTAL		1.00000

Michigan Public Service Commission
DTE Electric Company
Demand and Energy Allocation
Percentages By Rate Class
4th Large Load Study Forecast Power Suppl
Input to Subtransmission Lines
Allocation Schedule 202B

Line No.	(a) Rate Description	(b) COS Class	(c) 4th Large Load Study Demand Schedule 202B Allocation Factors
1	Residential		
2	Residential	Residential Secondary	-
3	Residential O.P.L.	E1/E2/D9	-
4	**Total Residential**		0.00000
5			
6	Secondary		
7	General Service	Commercial Secondary	-
8	Commercial O.P.L	E1/E2/D9	-
9	Traffic and Signal Lights	E1/E2/D9	-
10	**Total Secondary**		0.00000
11			
12	Primary		
13	Primary Distribution	Primary	0.00000
14	Subtransmission	Subtransmission	1.00000
15	Transmission	Transmission	-
16	**Total Primary**		1.00000
17			
18	Street Lighting	E1/E2/D9	-
19			
20	TOTAL		1.00000

Michigan Public Service Commission
DTE Electric Company
Demand and Energy Allocation
Percentages By Rate Class
4th Large Load Study Forecast Power Suppl
Input to Subtransmission Lines
Allocation Schedule 202C

Case No.: U-22046
Exhibit: Revised A-39
Schedule: Revised AD8
Witness: Q. Gerdes

	(a)	(b)	(c)
Line No.	**Rate Description**	**COS Class**	**4th Large Load Study Demand Schedule 202C Allocation Factors**
1	Residential		
2	Residential	Residential Secondary	0.52486
3	Residential O.P.L.	E1/E2/D9	0.00026
4	**Total Residential**		0.52512
5			
6	Secondary		
7	General Service	Commercial Secondary	0.26187
8	Commercial O.P.L	E1/E2/D9	0.00099
9	Traffic and Signal Lights	E1/E2/D9	0.00068
10	**Total Secondary**		0.26353
11			
12	Primary		
13	Primary Distribution	Primary	0.18428
14	Subtransmission	Subtransmission	0.02359
15	Transmission	Transmission	-
16	**Total Primary**		0.20787
17			
18	Street Lighting	E1/E2/D9	0.00348
19			
20	TOTAL		1.00000

Michigan Public Service Commission
DTE Electric Company
Demand and Energy Allocation
Percentages By Rate Class
4th Large Load Study Forecast Power Suppl
Primary Voltage Substation
Allocation Schedule 203A

Case No.: U-22046
Exhibit: Revised A-39
Schedule: Revised AD8
Witness: Q. Gerdes

	(a)	(b)	(c)
Line No.	**Rate Description**	**COS Class**	**4th Large Load Study Demand Schedule 203A Allocation Factors**
1	Residential		
2	Residential	Residential Secondary	0.53754
3	Residential O.P.L.	E1/E2/D9	0.00027
4	**Total Residential**		0.53781
5			
6	Secondary		
7	General Service	Commercial Secondary	0.26819
8	Commercial O.P.L	E1/E2/D9	0.00101
9	Traffic and Signal Lights	E1/E2/D9	0.00069
10	**Total Secondary**		0.26990
11			
12	Primary		
13	Primary Distribution	Primary	0.18873
14	Subtransmission	Subtransmission	-
15	Transmission	Transmission	-
16	**Total Primary**		0.18873
17			
18	Street Lighting	E1/E2/D9	0.00357
19			
20	TOTAL		1.00000

Michigan Public Service Commission
DTE Electric Company
Demand and Energy Allocation
Percentages By Rate Class
4th Large Load Study Forecast Power Suppl
Primary Voltage Substation
Allocation Schedule 203B

Case No.: U-22046
Exhibit: Revised A-39
Schedule: Revised AD8
Witness: Q. Gerdes

	(a)	(b)	(c)
Line No.	**Rate Description**	**COS Class**	**4th Large Load Study Demand Schedule 203B Allocation Factors**
1	Residential		
2	Residential	Residential Secondary	-
3	Residential O.P.L.	E1/E2/D9	-
4	**Total Residential**		0.00000
5			
6	Secondary		
7	General Service	Commercial Secondary	-
8	Commercial O.P.L	E1/E2/D9	-
9	Traffic and Signal Lights	E1/E2/D9	-
10	**Total Secondary**		0.00000
11			
12	Primary		
13	Primary Distribution	Primary	-
14	Subtransmission	Subtransmission	0.35011
15	Transmission	Transmission	0.64989
16	**Total Primary**		1.00000
17			
18	Street Lighting	E1/E2/D9	-
19			
20	TOTAL		1.00000

Michigan Public Service Commission
DTE Electric Company
Demand and Energy Allocation
Percentages By Rate Class
4th Large Load Study Forecast Power Suppl
Primary Voltage Substation
Allocation Schedule 203C

Case No.: U-22046
Exhibit: Revised A-39
Schedule: Revised AD8
Witness: Q. Gerdes

	(a)	(b)	(c)
Line No.	**Rate Description**	**COS Class**	**4th Large Load Study Demand Schedule 203C Allocation Factors**
1	Residential		
2	Residential	Residential Secondary	0.51021
3	Residential O.P.L.	E1/E2/D9	0.00025
4	**Total Residential**		0.51047
5			
6	Secondary		
7	General Service	Commercial Secondary	0.25428
8	Commercial O.P.L	E1/E2/D9	0.00096
9	Traffic and Signal Lights	E1/E2/D9	0.00066
10	**Total Secondary**		0.25589
11			
12	Primary		
13	Primary Distribution	Primary	0.17886
14	Subtransmission	Subtransmission	0.01800
15	Transmission	Transmission	0.03340
16	**Total Primary**		0.23026
17			
18	Street Lighting	E1/E2/D9	0.00338
19			
20	TOTAL		1.00000

Michigan Public Service Commission
DTE Electric Company
Demand and Energy Allocation
Percentages By Rate Class
4th Large Load Study Forecast Power Suppl
Primary Lines
Allocation Schedule 204

Case No.: U-22046
Exhibit: Revised A-39
Schedule: Revised AD8
Witness: Q. Gerdes

	(a)	(b)	(c)
Line No.	**Rate Description**	**COS Class**	**4th Large Load Study Demand Schedule 204 Allocation Factors**
1	Residential		
2	Residential	Residential Secondary	0.59438
3	Residential O.P.L.	E1/E2/D9	0.00030
4	**Total Residential**		0.59467
5			
6	Secondary		
7	General Service	Commercial Secondary	0.29655
8	Commercial O.P.L	E1/E2/D9	0.00112
9	Traffic and Signal Lights	E1/E2/D9	0.00076
10	**Total Secondary**		0.29844
11			
12	Primary		
13	Primary Distribution	Primary	0.10344
14	Subtransmission	Subtransmission	-
15	Transmission	Transmission	-
16	**Total Primary**		0.10344
17			
18	Street Lighting	E1/E2/D9	0.00345
19			
20	TOTAL		1.00000

Michigan Public Service Commission
DTE Electric Company
Demand and Energy Allocation
Percentages By Rate Class
4th Large Load Study Forecast Power Suppl
Secondary Line Transformers
Allocation Schedule 205

Case No.: U-22046
Exhibit: Revised A-39
Schedule: Revised AD8
Witness: Q. Gerdes

	(a)	(b)	(c)
Line No.	**Rate Description**	**COS Class**	**4th Large Load Study Demand Schedule 205 Allocation Factors**
1	Residential		
2	Residential	Residential Secondary	0.66271
3	Residential O.P.L.	E1/E2/D9	0.00033
4	**Total Residential**		0.66304
5			
6	Secondary		
7	General Service	Commercial Secondary	0.33046
8	Commercial O.P.L	E1/E2/D9	0.00125
9	Traffic and Signal Lights	E1/E2/D9	0.00085
10	**Total Secondary**		0.33257
11			
12	Primary		
13	Primary Distribution	Primary	-
14	Subtransmission	Subtransmission	-
15	Transmission	Transmission	-
16	**Total Primary**		0.00000
17			
18	Street Lighting	E1/E2/D9	0.00440
19			
20	TOTAL		1.00000

Michigan Public Service Commission
DTE Electric Company
Demand and Energy Allocation
Percentages By Rate Class
4th Large Load Study Forecast Power Suppl
Secondary Distribution Lines
Allocation Schedule 300

Case No.: U-22046
Exhibit: Revised A-39
Schedule: Revised AD8
Witness: Q. Gerdes

	(a)	(b)	(c)
Line No.	**Rate Description**	**COS Class**	**4th Large Load Study Demand Schedule 300 Allocation Factors**
1	Residential		
2	Residential	Residential Secondary	0.87360
3	Residential O.P.L.	E1/E2/D9	0.00012
4	**Total Residential**		0.87372
5			
6	Secondary		
7	General Service	Commercial Secondary	0.12501
8	Commercial O.P.L	E1/E2/D9	0.00012
9	Traffic and Signal Lights	E1/E2/D9	0.00062
10	**Total Secondary**		0.12575
11			
12	Primary		
13	Primary Distribution	Primary	-
14	Subtransmission	Subtransmission	-
15	Transmission	Transmission	-
16	**Total Primary**		0.00000
17			
18	Street Lighting	E1/E2/D9	0.00053
19			
20	TOTAL		1.00000

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-22046
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS

AND

REVISED DIRECT TESTIMONY

OF

ALLEN J. KRYSCYNSKI JR

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

Line No.

1 **Background & Qualifications**

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

3 A1. My name is Allen J. Kryscynski Jr, and my business address is One Energy Plaza,
4 Detroit, Michigan, 48226. I am employed by DTE Electric Company ("DTE
5 Electric" or the "Company").

6

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

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

9

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

11 A3. I earned a Bachelor of Science from the University of Michigan School of Natural
12 Resources and Environment with a dual concentration in environmental policy and
13 natural resource management. I also received a master's degree in Business
14 Administration (MBA) from the University of Michigan.

15

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

17 A4. I held several positions with ITC Holdings, including as Senior Regulatory Analyst,
18 and a variety of positions within the Local Community and Community Affairs
19 team, culminating as a Senior Local Government and Community Affairs
20 Representative. At ITC Holdings, I worked on Federal Energy Regulatory
21 Commission ("FERC") and Midcontinent Independent System Operator ("MISO")
22 regulatory issues and represented ITC Holdings at community meetings regarding
23 new transmission substations and transmission lines.

Line No.

1 I joined DTE Energy in 2014 as a Strategy and Corporate Development Associate
2 in the Corporate Strategy group. In this role, I did work on the initial Distribution
3 Operations ("DO") investment strategy project to determine distribution grid
4 investment needs as well as work on DTE Electric workforce projections and
5 requirements for both the DO and Fossil Generation business units. In 2016, I was
6 appointed Manager of Distribution Operations Strategy and assumed responsibility
7 for continued work to evolve the distribution operations investment strategy,
8 operations strategy, and the chief of staff role for the Senior Vice President of
9 Distribution Operations. In early 2018, I was appointed Manager in Project
10 Management with responsibility to start and operationalize the 4.8kV Hardening
11 Program to remove City of Detroit arc wire and harden the City of Detroit electrical
12 infrastructure. Later in 2018, I was appointed Manager of Tree Trim Strategy,
13 where I was responsible for managing the initial Tree Trim Surge rate case, Tree
14 Trim contractor negotiations, the Tree Trim strategy for scheduling work, and
15 providing an adequate supply of tree trimmers necessary to complete the work. In
16 2020 I took over the Tree Trim Operations Manager position and managed day-to-
17 day Tree Trim operations, including overseeing all of DTE Electric's internal
18 arborists and foresters as well as eight tree trim contractors and their 1,600+
19 employees. In 2022 I was appointed as Manager of Distribution Operations
20 Regulatory Strategy and Grid Modernization, and promoted to Director in 2023.
21
22 **Q5. What are your current duties and responsibilities?**
23 A5. As Director of Distribution Operations Long Term Capital Planning and Regulatory
24 Operations, I have two primary areas of responsibility: 1) managing Distribution
25 Operations regulatory activities, including rate cases, the Distribution System Plan

Line No.

filing, required reporting, and various Company/MPSC collaboratives, and 2) Distribution Operations long term grid modernization strategy.

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

A6. Yes. I sponsored testimony in the following cases

- U-21297 DTE Electric Company 2023 Rate Case
- U-21534 DTE Electric Company 2024 Rate Case
- U-21860 DTE Electric Company 2025 Rate Case

Overview and Executive Summary

Q7. What is the purpose of your testimony?

A7. The purpose of my testimony is to support, as reasonable, prudent, and necessary, the historical O&M expenses related to electric distribution activities for the 2025 historical period and projected expenses for 2026 through February 29, 2028. Additionally, my testimony describes and supports (1) the Distribution O&M overview, (2) the Company's GPM, (3) the Company's Reliability Model, (4) Model Transparency (5) the Company's approach to EJ, with corresponding exhibits.

Q8. How is your testimony organized?

A8. My testimony consists of five parts:

Part I Distribution O&M Overview and Exhibits

Part II Global Prioritization Model

Part III Reliability Model

Line No.

1 Part IV Model Transparency

2 Part V Environmental Justice

3

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

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

Exhibit	Schedule	Description
A-13	C5.6 Revised	Projected Operation and Maintenance Expenses – Distribution Expenses
A-23	M7	Reliability Model Output
A-23	M8	Global Prioritization Model Project and Program Rankings
A-23	M8.1	Global Prioritization Model
A-23	M17	Unused EJ-Alternative Global Prioritization Model Project and Program Rankings
A-23	M17.1	Unused EJ-Alternative Global Prioritization Model
A-23	M18	Environmental Justice Reliability Analysis
A-23	M19	Effectiveness Curves

17

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

19 A10. Yes, they were.

20

21 **Q11. Please summarize your testimony.**

22 A11. In my testimony I present an overview of the Company's Distribution Operations
23 expenditures which support improvements in safety, reliability, and customer
24 experience. Distribution operations directly affects customers every day, and recent
25 investments have contributed to positive performance outcomes described by

Line No.

1 Witness Chiu that help customers receive safe and reliable electric service. My
2 testimony also explains why continued, sustained investment is necessary to
3 maintain and build on this performance over the long term. In addition to the normal
4 cost of continuing to prudently operate the system, the Company is proactively
5 addressing an acknowledgment made by the Liberty Audit ("Audit")[1] that the
6 system is aging, and additional and sustained investment is needed to safely and
7 reliably serve customers in the long term. To that end, the Company is requesting
8 $534.5 million in Operations and Maintenance ("O&M") expenses in the test year
9 to enhance the reliability, safety, and resilience of the electric distribution system.
10 My testimony explains how this funding supports critical maintenance,
11 infrastructure improvements, and workforce expansion to meet both growing
12 demand and evolving challenges.
13
14 In addition to the Company's O&M request, I explain how the Company prioritized
15 the capital projects presented in this case through use of its Global Prioritization
16 Model ("GPM") and Reliability Model. Using several impact dimensions, the
17 GPM transparently and effectively ranks potential projects based on the benefits
18 they would deliver for a given level of investment. In this case, the Company
19 discusses the Environmental Justice ("EJ") multiplier and possible future changes
20 for consideration. I also introduce a new Reliability Model that, like the previous
21 versions, estimates tangible reliability improvements associated with proposed
22 capital investments in a data-driven framework on a circuit-by-circuit basis. This

[1] The DTE Electric Utility Distribution Audit Report ("Liberty Audit") was conducted by Liberty Consulting Group and filed in Case No. U-21305. Though the title indicates DTE Energy Company (DTE Energy), the audit findings apply to DTE Electric, a wholly owned subsidiary of DTE Energy. The DTE Electric Audit Reports are available in filing ## U-21305-0012 and U-21305-0013 at https://mi-psc.my.site.com/s/case/5008y000005KkdgAAC/ (accessed February 15, 2025)

Line No.

1 rigorous analysis produces high confidence in the prioritization and reliability
2 impact for each of the selected projects and programs.
3
4 I also discuss the Company's model transparency efforts for both the benefit-cost
5 analysis ("BCA") discussed in Witness Chiu's testimony and the new Reliability
6 Model that I discuss here. Staff and interested parties will have the opportunity to
7 completely examine and ask questions about the models presented as part of
8 evidentiary support for the distribution activities addressed in this case.
9
10 Finally, I discuss the Company's ongoing commitment to EJ. The Company takes
11 EJ into account when planning its distribution system investments by 1)
12 incorporating EJ considerations in investment decisions through use of an EJ
13 multiplier in the GPM; 2) improving system performance for vulnerable
14 communities experiencing poor reliability through the distribution investment
15 programs; and 3) providing support to vulnerable customers experiencing outages
16 during storms through community outreach efforts. Based on a recent analysis of
17 System Average Interruption Duration Index ("SAIDI") and System Average
18 Interruption Frequency Index ("SAIFI") metrics by census tract, the Company's
19 most vulnerable customers, on average, continue to experience more reliable
20 electric service than the rest of the system. In addition, an evaluation of planned
21 and ongoing investments shows that a significant portion of the Company's
22 reliability improvement work is being conducted in vulnerable communities. The
23 Company will continue investing in EJ communities through the programs and
24 projects presented in this case. Lastly, the Company has presented new EJ focused

Line No.

1 regression analysis, changing demographics analysis, and additional EJ analysis as
2 required by the Commission's recent Order in Case No. U-21860.
3
4 **PART I: Distribution O&M Overview and Exhibits**
5 **Q12. What level of O&M spending is the Company proposing for the projected test**
6 **period to support Distribution Operations in operating and maintaining the**
7 **grid?**
8 A12. Supporting the core functions of operating and maintaining the distribution system,
9 the Company is proposing $534.5 million of O&M expenses to support Distribution
10 Operations in the projected test period as shown in Exhibit A-13, Schedule C5.6
11 Revised, Page 1, Line 27. This consists of approximately $145.2 million in
12 projected distribution operation expenses and approximately $389.2 million of
13 maintenance expenses.
14
15 **Q13. What essential operations and maintenance activities are included in the O&M**
16 **exhibit for Distribution Operations?**
17 A13. Exhibit A-13, Schedule C5.6 Revised identifies the key activities necessary for
18 prudently and reliably managing the operations and maintenance of the Company's
19 distribution system. These include operation expenses related to supervision,
20 engineering, load dispatching, station, overhead and underground line operations,
21 and customer meter and installation activities, among other distribution costs. It
22 also includes maintenance costs, which focus on inspecting, repairing, sustaining,
23 and enhancing the distribution infrastructure, with funds allocated for the upkeep
24 of station equipment, overhead and underground lines, and line transformers. I
25 address certain major Distribution Operations O&M cost components later in my

Line No.

1 testimony while other cost components are addressed in more detail by other
2 witnesses. Specifically, Witness Hartley addresses street lighting and signal
3 systems, Witness Robinson addresses corrective maintenance, preventative
4 maintenance and pole top maintenance and modernization, Witness Hill addresses
5 Emergent Expenses and Damage Prevention, Witness Rademacher addresses
6 ADMS: Network Management System and Next-Gen AMI, and Witness
7 Hutchinson addresses vegetation management expenses.
8
9 **Q14. What do the line items listed under Distribution Expenses in Exhibit A-13,**
10 **Schedule C5.6 Revised describe?**
11 A14. The costs associated with dispatching, coordinating restoration, and vegetation
12 management efforts are included in FERC accounts 580 (Operation Supervision
13 and Engineering) and 581 (Load Dispatching). Accounts 582 (Station Expenses),
14 583 (Overhead Line Expenses), 584 (Underground Line Expenses), and 588
15 (Miscellaneous Expenses) incorporate the costs for developing and implementing
16 training and work force planning for the Company's substation operators and
17 maintenance personnel, apprentice lineman, splicers, technicians, engineers,
18 riggers, and planners as well as the staff groups to support these critical efforts. Job
19 skills training is conducted for the safety of employees and the public. Witness
20 Hartley supports account 585 (Street Lighting and Signal System Expense). Meter
21 testing and distribution costs are incorporated into account 586 (Meter Expenses).
22 Account 587 (Customer Installations Expenses) includes expenses to support the
23 specific needs of customers served at primary voltages. Account 589 (Rents)
24 reflects the expenses associated with leased facilities and attaching to poles not
25 owned by the Company.

Line No.

1 **Q15. Can you provide an overview of the Company's O&M cost request and explain**
2 **why these costs are essential to delivering safe and reliable service?**
3 A15. Yes. The Company's core responsibility is to provide safe and reliable electric
4 service for customers who depend on this essential service to support their homes,
5 businesses, and livelihoods. The Company takes that responsibility seriously, and
6 the DO team is at the center of executing on this core function. While DTE Electric
7 is advancing a range of initiatives across its broader operations, the Company's
8 Distribution Operations-related O&M request is focused on securing the funding
9 necessary to fulfill its most fundamental obligation: maintaining and sustaining a
10 reliable power delivery system for customers. Just as routine vehicle maintenance
11 is essential to keep a car running reliably, the presented O&M costs represent work
12 the Company must do to keep its distribution system functioning.
13
14 Furthermore, as discussed in Witness Chiu's testimony, the Company's electrical
15 grid is one of the oldest in the country and in need of continued maintenance and
16 investment to enable the Company to continue to provide the safe and reliable
17 electric service our customers demand. O&M is essential to sustained operations to
18 deliver this safe and reliable electric service. Witness Robinson highlights work for
19 Preventive and Corrective Maintenance that is designed to proactively inspect,
20 maintain, and remediate aging and defective equipment that must be executed to
21 sustain and repair the electrical grid. Additionally, Witness Hutchinson explains the
22 critical importance that vegetation management plays to continue to improve the
23 Company's reliability performance.

Line No.

1 The O&M costs supported in my testimony and in this case are targeted at critical
2 maintenance activities as well as needed system repairs. The O&M cost request is
3 designed to ensure the continued delivery of high-quality service to customers
4 while accounting for the evolving demands on the grid. The determination of O&M
5 expenses accounts for, among other things, inflation-adjusted historical costs,
6 known and measurable changes, and projected operational needs. The request also
7 considers external factors such as the increased frequency of severe weather events,
8 which directly influence emergent costs and necessitate prudent planning for future
9 system reliability. In this section, I describe the specific maintenance activities
10 included in this request and explain how these costs were derived and adjusted to
11 reflect projected needs.
12
13 **Q16. What do the line items listed under Maintenance in Exhibit A-13, Schedule**
14 **C5.6 Revised describe?**
15 A16. Maintenance work is critical to providing safe and reliable service. Account 591
16 (Maintenance of Structures) is to support the routine maintenance of existing
17 physical structures associated with the electric distribution system such as
18 substation control buildings. Emergent, troubleshooting and reactive maintenance
19 work associated with substation, overhead and underground equipment is included
20 in accounts 592 (Maintenance of Station Equipment), 593 (Maintenance of
21 Overhead Lines), and 594 (Maintenance of Underground Lines), respectively. In
22 addition, account 593 includes the vegetation management expenses supported by
23 Witness Hutchinson. The supervision and other support costs for these important
24 efforts are included in account 590 (Maintenance Supervision and Engineering).

Line No.

Witness Hartley supports account 596 (Maintenance of Street Lighting and Signal Systems).

Q17. How was the projected O&M expense amount in column (l) of Exhibit A-13, Schedule C5.6 Revised, page 1, derived?

A17. First, the 12-month historical test period was provided in column (c), then was adjusted to include the emergent five-year average, in column (e) to arrive at the adjusted 12-month historical balance. Second, the adjusted 12-month historical test period in column (f) is adjusted for inflation in column (g) through (i). Third, other adjustments are added in column (j). The sum of columns (g) through (j) are found in column (k). The sum of column (f) and column (k) result in the projected O&M expense shown in column (l).

Q18. Can you explain the normalization adjustments reflected in column (e) on Exhibit A-13, Schedule C5.6 Revised?

A18. Column (e) on line 27 is an O&M increase of $47.3 million for emergent expenses.

Q19. How is the $47.3 million of emergent normalization calculated and how does it relate to the actual spend from 2025?

A19. As presented on page 3 of Exhibit A-13, Schedule C5.6 Revised, the Company forecasted emergent costs using a consecutive five-year average, 2021 through 2025, to develop the projected test year in the instant case. This averaging method smooths out year-to-year variation, which has the effect of moderating the variable cost impacts of extreme weather event spikes over time. The Commission has supported this methodology in previous rate cases, including in the most recent U-

Line No.

21860 Order.[2] The approximately $47.3 million normalization adjustment is the difference between the five-year average[3] and the 2025 actual.

Q20. What projected adjustments did you make to O&M as reflected in columns (g) through (i)?

A20. Increases based on the inflation rate, as described by Witness Uzenski, were applied to the adjusted historical test period expenses for the period January 1, 2026 through February 29, 2028.

Q21. What changes are shown in the Other Adjustments in column (j) of Exhibit A-13, Schedule C5.6 Revised, page 1?

A21. These changes are known and measurable adjustments to Distribution expenses in order to account for costs that can be specifically identified, quantified, and tracked. Exhibit A-13, Schedule C5.6 Revised, page 2, footnote 6, details all items in Other Projected Adjustments as well as the witnesses that support these adjustments. These items represent investments required to support and establish adjustments to the base O&M amounts for the period from 2026 through the projected test year, including but not limited to:

- Maintenance of Overhead Lines-Vegetation Management, Line 19, highlights a $122.1 million increase in Vegetation Management base O&M needed to maintain the current tree trim maintenance schedule, and proposed specification changes the Company is exploring. This adjustment is discussed further by Witness Hutchinson.

[2] Case No. U-21860 Order, February 19, 2026, pg. 96.
[3] In the instant case the Company has used a nominal five-year average.

Line No.

- Adjustments related to Preventative Maintenance, Pole Top Maintenance and Modernization ("PTMM") program inspections, Corrective Maintenance, and System Cable Testing program result in an increase of $26.5 million. These adjustments, which align to Audit recommendations, represent costs associated with the upkeep and reliability improvements of critical substation assets, related infrastructure, pole replacements, conductor upgrades, other structural repairs, underground cable maintenance, and inspections, as discussed further by Witness Robinson. These expenses are spread over multiple lines in Exhibit A-13, Schedule C5.6 Revised, page 1.
- An adjustment of $6.9 million is required for workforce augmentation, reflecting additional engineering and support personnel needed to support the Company's current investment plan.
- Next-Generation AMI has an adjustment of $3.6 million. This work modernizes metering infrastructure to mitigate obsolescence risk, maintain existing AMI benefits, and add functionality that enables more timely and accurate information to support grid operations and customer needs. This adjustment is discussed further by Witness Rademacher.

Q22. Why is the Company proposing workforce augmentation that increases its engineering and support personnel?

A22. The Company's need for additional engineering personnel is driven by the increasing complexity and scale of its distribution system transformation, as well as a need to support the increased level of capital investment planning and engineering. A strong engineering workforce, supported by operational, analytical,

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technical and field support is needed to advance the Company's growth initiatives while strengthening system reliability performance. For example, this support will be essential to execute on the Company's plans established in the 2026 Distribution System Plan ("DSP") as discussed by Witness Chiu, which include a variety of initiatives to improve electric safety, grid reliability, resilience and capacity.[4] They are needed to support significant planned automation efforts, including incorporation of new smart devices and work on the Fault Location, Isolation and Service Restoration ("FLISR") project. Additional engineering staff will also serve an important role in incorporating a variety of Outage Management System ("OMS") accuracy improvements, as well as support reliability upgrades targeting data integrity and process-oriented enhancements. The Company is planning for increasing forecasted distributed energy resources ("DERs") interconnection volumes, which will require additional workforce and engineering expertise to accommodate. The Company's plan to add additional engineering and support personnel also addresses resource gaps in the Company's engineering groups that have resulted through normal attrition of key engineering personnel and subject matter experts. To continue to maintain and improve Distribution Operations, these critical resource gaps must be addressed. Without additional in-house engineering expertise, the Company risks delays in project execution, inefficiencies in system upgrades, and challenges in maintaining long-term reliability goals and improvements. Expanding the engineering workforce is essential to successfully navigating these operational demands while providing for the transfer and retention of critical technical knowledge.

[4] Exhibit A-23 Schedule M1.

Line No.

The Company's distribution system will undergo a significant transformation in the coming years, and the Company must be prepared to both execute these changes and operate under a modernized system. The Company is and will continue to actively expand its engineering personnel over the bridge and test years to meet the growing engineering demands and to enhance operational capabilities. The expenses will fund incremental in-house engineering personnel. The Company began incurring incremental O&M expenses in 2025 to address initial hiring needs, with staffing additions phased in through 2028 to support personnel required for ongoing business activities.

In addition to in-house engineering staff, the Company is currently optimizing the workforce augmentation by expanding partnerships with engineering and design firms to perform detailed design work. These partnerships leverage contracting models, like engineering, procurement, and construction agreements, to increase capacity and work volume, while adding flexibility as specific engineering needs change over time. While external engineering services are an effective supplement to the Company's workforce, the Company's engineers remain essential to provide critical oversight, ensure quality control and support cost-effective project development. By increasing the overall engineering workforce, the Company will improve project efficiency and support the long-term reliability goals discussed by Witness Chiu, while ensuring critical engineering, technical and Company knowledge and skills are maintained as well as transferred to new team members.

Line No.

1 **Q23. Does the Company agree with the Audit recommendation, and how is that**
2 **recommendation reflected in Commission decisions regarding workforce**
3 **augmentation levels in Distribution O&M?**
4 A23. Yes. As previously addressed in Case U-21860, the Company requested workforce
5 augmentation, including additional engineering and support personnel, to support
6 new and expanding initiatives. The Commission found that "DTE Electric
7 adequately supported the need for these positions," based, in part, on the findings
8 in the Liberty Audit.[5]
9
10 The Audit noted that additional engineering resources would be required for the
11 Company to meet its reliability targets. Specifically, the Audit stated that DTE
12 Electric "appears to require significantly more engineering personnel" and further
13 observed that insufficient engineering resources could result in delays to program
14 execution and reduced effectiveness and efficiency.[6]
15
16 **Q24. Has the Company adjusted its workforce augmentation plans since its filing in**
17 **U-21860?**
18 A24. Yes. The market for engineering talent is competitive, and the pace of hiring has
19 lagged the Company's initial expectations. Through the end of 2025 the Company
20 has added a net of 18 engineers and support personnel with plans to add an
21 additional 85 in 2026, 85 in 2027, and 21 in the full calendar year 2028 to complete
22 the workforce augmentation plan of 209 additional engineering and support
23 personnel.

[5] Case No. U-21860 February 19, 2026 Order pg. 209.
[6] Case No. U-21305; Part Two, Pg. 15.

Line No.

1 **Q25. Has the Company adjusted its O&M request in accordance with the adjusted**
2 **workforce augmentation plan?**
3 A25. Yes. The Company originally requested $8.3 million in Case No. U-21860 for
4 additional engineers and support personnel for calendar year 2026, which included
5 positions that were to be hired in 2025. Since a net of 18 people were hired in 2025
6 at an annual cost of ~$715,000, this spend is included in our 2025 historical actuals
7 and no longer part of the other projected adjustments in the Exhibit A-13 Schedule
8 C5.6 Revised page 2. The remaining investment to complete the workforce
9 augmentation plan will be spread across 2026-2028 in accordance with the
10 proportional headcount. The Company is requesting $3.4 million in 2026, $3.4
11 million in 2027, and $0.1 million in the first two months of 2028.
12
13 **Q26. In Case U-21860, did the Commission approve the Company's Distribution**
14 **O&M projection adjustments similar to those proposed in Company Exhibit**
15 **A-13 and discussed in the testimony above?**
16 A26. Yes. Apart from inflation differences, the Commission found reasonable and
17 prudent all Company Distribution O&M adjustments in Case No. U-21860.
18
19 **Q27. If the adjustments were approved in Case No. U-21860, why are they being**
20 **requested again?**
21 A27. The adjustments approved in Case No. U-21860 were for the 2026 test year. The
22 historic test year in this case is 2025, which means most of the adjustments are not
23 in historic actuals and need to be requested again for the future test year in this
24 instant case.

Line No.

Q28. Why are many of the requested adjustments different than the amounts requested in Case No. U-21860?

A28. There are three main reasons for the changes, and more than one can be true for any given projected adjustment:

1) Part of an individual adjustment has been captured in the historical test year. An example of this happening is shown above in my testimony on workforce augmentation.
2) New information is available allowing the Company to make improved adjustment projections. Witness Robinson's testimony on forecasted preventive maintenance expense is an example of this type of adjustment change.
3) The company has implemented program and assumption changes that align to higher work volumes as expected following the order in U-21860. Witness Hutchinson's testimony on the vegetation management program is an example of this type of adjustment change.

Q29. Are there new adjustments requested in this case?

A29. Yes. Next-Gen AMI sponsored by Witness Rademacher is new in this instant case. Vegetation Management is not new and was named Tree Trim in case U-21860. ADMS: Network Management System is also not new and was previously NMS/ESRI Data Quality Controls in Case U-21860. Preventative Maintenance Backlog has been shortened to Preventive Maintenance.

PART II: Global Prioritization Model

Q30. Can you summarize the Company's GPM framework and how the GPM framework supports the prioritization of DO capital strategic investments?

Line No.

1 A30. The GPM is a tool the Company's Distribution Operations team developed in 2018
2 to prioritize investments. See Exhibit A- 23 Schedules M8 and M8.1. The GPM
3 accomplishes this by developing a relative ranking based on the benefits the project
4 or program delivers for a given level of investment. The ranking is accomplished
5 through a process of an economic evaluation method, the "best-fit, most reasonable
6 cost," to prioritize projects across eight impact dimensions that are aligned to the
7 DTE Electric planning objectives. Applying this economic evaluation method, the
8 GPM develops a total project score based on the weighting of each impact
9 dimension. Each of the eight impact dimensions within the GPM measures a
10 benefit of the project or program. Once the dimension scores are summed, an EJ
11 multiplier is applied and projects delivering the most value are prioritized for earlier
12 investment. The model results serve as the initial basis for the Company's
13 investment prioritization and highlight those projects that have the highest relative
14 benefit and/or are most urgent. In sum, the GPM helps the Company compare over
15 a hundred vastly different types of projects and programs of different sizes and
16 identify, within an analytical framework, which ones will be the most beneficial for
17 customers.
18
19 **Q31. Does the GPM consider benefits and costs?**
20 A31. Yes. As I noted above, each of the eight impact dimensions within the GPM
21 measures a benefit of the project or program. These benefits are weighed against
22 costs in each of the dimensions. The GPM primarily provides a tool to prioritize
23 the Company's investments. As Witness Chiu explains, however, the Company is
24 continuing to refine its analysis of costs and benefits through an ongoing effort to
25 incorporate greater benefit-cost analysis ("BCA") as a complement to applying the

Line No.

1 GPM. In the context of the GPM, benefits are not converted to dollars, so a Benefit
2 Cost Ratio ("BCR") is not generated as it would be with a traditional BCA.
3
4 **Q32. What was the Audit's assessment of the GPM?**
5 A32. The Audit discussed the significant progress of the GPM since its inception in
6 2018. Specifically, the Audit stated:
7
8 "We found DTE's modeling used for evaluating, comparing, and
9 prioritizing reliability initiatives, sound. DTE's Global Prioritization model,
10 which systematically compares and evaluates competing system
11 improvement and reliability-enhancing projects and programs across 10
12 important improvement dimensions, seems a balanced and logical
13 application of the "best fit, most reasonable cost" economic approach to
14 investment optimization. Its application at DTE Electric is consistent with
15 other utility strategic investment good practices that Liberty has
16 experienced.[7]" The Audit also noted that the Company's has made strides
17 in incorporating Environmental Justice into its distribution planning
18 processes.[8]
19
20 **Q33. Has the Company recently refined the GPM in response to direction by the**
21 **Commission?**
22 A33. Yes. First, in its Order dated January 23, 2025, in Case No. U-21534 the
23 Commission found that the Company has responded to its directive for increased
24 transparency regarding the foundation of the GPM and a clearer explanation of any

[7] Case No. U-21305; Part Two, pg. 24-25 (Conclusion No. 7)
[8] Case No. U-21305; Part Two, pg. 23

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1 deviations.[9] The Commission acknowledged the Company's efforts to provide a
2 more comprehensive understanding of these aspects, noting that "[t]he Commission
3 sees progress in the Company's efforts at transparency in this case,"[10] and
4 ultimately concluding that there was no need for the Company to implement
5 extensive changes to its modeling processes. Second, in its Order dated June 12,
6 2025 in Case U-21305, the Commission asked for the Company to "balance capital
7 investments with O&M, in order to ensure that investments are prioritized in the
8 most cost-effective manner."[11] The GPM has been refined by including O&M
9 investments, including Vegetation Management and five Preventative Maintenance
10 programs.
11
12 **Q34. What determines whether a project is scored in the GPM?**
13 A34. The engineering team evaluates alternatives to meet system needs and selects the
14 best project or program to move forward. If an investment is selected to move
15 forward, it is scored in the GPM for prioritization. The O&M investments selected
16 to be included in the GPM included Vegetation Management due to the size of the
17 investment, and the five largest preventative maintenance programs by annual
18 investment levels.
19
20 **Q35. How does the GPM consider DTE Electric's planning objectives when**
21 **evaluating the Company's distribution investments?**
22 A35. The Company uses the GPM to assess the benefits that strategic investments have
23 on the distribution system as they relate to each of the Company's five planning

[9] Case No. U-21534 January 23, 2025 Order pg. 97.
[10] Case No. U-21534 January 23, 2025 Order pg. 97.
[11] Case No. U-21305 June 12, 2025 Order pg. 30.

Line No.

1 objectives, which are: 1) Safety, 2) Reliability and Resiliency, 3) Affordability, 4)
2 Customer Accessibility and Community Focus, and 5) Clean Energy. All impact
3 dimensions measured in the GPM, as well as the new EJ Multiplier, are aligned to
4 one or more of these five planning objectives as described in Table 1. These five
5 objectives also align with the Commission's overarching objectives for the electric
6 distribution system, which are safety, reliability and resilience, cost effectiveness
7 and affordability, and accessibility.[12]
8
9 **Table 1 Mapping of GPM impact dimensions/multipliers to**
10 **Planning Objectives**

		Planning Objectives				
		Safe	Reliable and Resilient	Affordable	Clean	Customer accessible and community focus
GPM Impact Dimension	Reduce Electrical Hazards	✓		✓		
	Overload Relief	✓	✓	✓	✓	✓
	SAIDI	✓	✓	✓		
	SAIFI		✓			
	Major event risk	✓	✓	✓		
	Capacity Relief		✓		✓	✓
	O&M Avoidance			✓		
	Capital Avoidance			✓		
GPM Multiplier:						
Investment In EJ Communities						✓

11
12 **Q36. How does the EJ multiplier work?**
13 A36. The EJ multiplier allows projects with known benefits in EJ communities to be
14 recognized and valued. The multiplier ensures that projects selected by the model
15 demonstrate customer benefits, and within that group of projects, the prioritization

[12] See October 11, 2017 in Case No. U-18014 (pgs. 10-12) and August 20, 2020 order in Case No. U-20147 (pgs. 36-38).

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will favor those that have positive impacts on EJ communities. The EJ multiplier can range from 1.0 to 2.0 depending on the percentage of vulnerable customers impacted by the particular project or program. For example, if 80% of the customers affected by a circuit conversion project live in a vulnerable census tract, then the EJ multiplier would be 1.8 (number of vulnerable customers divided by total customers impacted by a project or program). The multiplier will increase the GPM score (the sum of the eight dimensions). As an example, if the GPM score is 100, using the example multiplier above, the final GPM score post multiplier would be 180. As a specific example in this case, the CODI: Kent/Gibson Conversion project has a score across the eight impact dimensions of 161. As 72% of the customers benefiting from this project live in vulnerable census tracts, the EJ multiplier is 1.72 and the final score is 276.

Q37. Did the Commission suggest reviewing possible changes to the EJ Multiplier in Case No. U-21860?

A37. Yes. The Order stated that "the Commission directs DTE Electric to better account for the number of residential customers on a given circuit rather than just the proportion of customers living in an EJ community, if possible, when prioritizing EJ in its GPM model[13]."

Q38. Did the Company review possible changes to the GPM EJ multiplier as directed by the Commission?

[13] Case No. U-21860 February 19, 2026 Order, pg. 423

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1 A38. Yes. The Company looked at two different methodologies to adjust the EJ
2 multiplier to account for total number of customers impacted by a program or
3 project:
4 1) Use total EJ customers impacted – This methodology sets the EJ multiplier
5 denominator to the highest total number of EJ customers impacted by a single
6 investment. In the GPM, the Vegetation Management program impacts every
7 EJ customer over a 5-year period and, as such, would affect the highest raw
8 number of EJ customers and receive a multiplier of 2.0. As another example a
9 project, 4.8kV Conversion: I-94 (Promenade), that impacts 12,882 EJ
10 customers would only receive an EJ multiplier of 1.02 (under the existing
11 methodology this project receives a multiplier of 1.96). The Company rejected
12 this method because it unfairly favors large system wide projects over smaller
13 projects. The intent of the GPM is to value projects and programs of different
14 size, cost, and duration on a level playing field (on a benefit per dollar invested
15 basis). This EJ methodology tilts the GPM exclusively in favor of large
16 programs, effectively undermining the purpose and goal of the combined
17 program and project prioritization. This methodology would also make the EJ
18 multiplier less meaningful in separating projects because virtually all of them
19 would have extremely low multipliers, between 1.0 and 1.04.
20 2) Include Commercial and Industrial Customers in the denominator – This
21 methodology was considered by the Company and is presented in this case for
22 further review by the Commission, Staff, and Stakeholders. In this methodology
23 both commercial and industrial customers are included in the denominator but
24 not included in the numerator. This methodology is an attempt to address
25 concerns that EJ scoring could unfairly weight projects that mostly benefit

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commercial and industrial customers. The benefit to this methodology is that it devalues projects that have larger numbers of commercial and industrial customers and favors projects with higher proportions of residential customers. The key drawback, and the reason why the Company chose not to adopt this methodology in this case, is that it lowers the overall EJ multipliers for virtually all projects and programs compared to the existing methodology. The Company has presented in Exhibit A-23 Schedule M17.1 as alternative GPM with this new methodology for review and consideration for future GPM iterations.

Q39. Why did the Company decide to stay with its current EJ multiplier approach?

A39. After considering these alternative approaches, the Company determined it is reasonable to continue using its original methodology with higher EJ multipliers because it believes that it is more reflective of the Commission's repeated guidance that EJ should be given a high priority in investment planning decisions.

Q40. Can you provide the full list of dimensions and associated weightings under the GPM as used in this case?

A40. Yes, the weightings are unchanged from Case No. U-21860. See Table 2 below.

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1 **Table 2 Global Prioritization Model Impact**

2 **Dimensions/Multiplier**

Impact Dimension	Drivers	Weight
Reduce Electrical Hazards	• Reduction in wire-down events	**3**
Overload Relief	• Elimination of overloaded equipment	
SAIDI	• Reduction in duration of outages	
SAIFI	• Reduction in frequency of outage events	
Major Event Risk	• Reduction in extensive substation outage events that lead to a large amount of stranded load for more than 24 hours	**2**
Capacity Relief	• Elimination of system capacity constraints	
O&M Avoidance	• Trouble event reduction and truck roll reduction • Preventive maintenance investment reduction	**1**
Capital Avoidance	• Trouble event reduction and truck roll reduction • Reduction in capital replacement either during equipment failures or avoided planned capital work	
Multiplying Factor		
Investment in EJ Communities	• 100% plus the percent of customers impacted by investment in EJ communities, such that the multiplication factor is 100% (or 1.0) if none of the customers impacted by a project live in vulnerable census tracts, and 200% (or 2.0) if all of the customers impacted by a project live in vulnerable census tracts • The initial total GPM score (sum of the other eight impact dimensions) is multiplied by the EJ factor (which ranges from 1.0 to 2.0) to provide a final GPM score	

3

4 **Q41. How are projects and programs ranked using the GPM?**

5 A41. Strategic investments are assessed, scored, and then ranked in a quantitative manner
6 on how they support and/or improve each impact dimension. Table 3 shows the
7 mapping of the investments to the impact dimensions in which they generally
8 receive a score based on the benefits the investment delivers.

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1 **Table 3 Selected programs and GPM impact dimensions/multiplier**

2

Investment Area	GPM Dimensions								GPM mult.
	Reduce Electrical Hazards	Overload Relief	SAIDI	SAIFI	Major Event Risk	Capacity Relief	O&M Avoidance	Capital Avoidance	Investment in EJ Communities
Substation Risk					X				*
4.8kV Hardening	X		X	X			X	X	X
PTMM	X		X	X			X	X	P
Cable Replacement			X	X	X			X	P
Frequent Outage			X	X			X	X	P
Breaker Replacement			X	X	X		X	X	P
URD Replacement			X	X			X	X	P
Subtransmission Redesign	X	X	X	X	X	X	X	X	*
CODI	X	X	X	X	X	X	X	X	*
4.8kV Conversion	X	X	X	X	X	X	X	X	*
System Loading	X	X	X	X	X	X	X	X	*
Automation	X		X	X					P
Vegetation Management	X		X	X			X	X	P
PM: 40 kV Pole-Top Switches			X	X					P
PM: Breakers			X	X				X	P
PM: Distribution Remote Devices			X	X					P
PM: URD Pad-mounted Transformers	X								P
PM: Overhead Capacitor and Regulator Controls							X	X	P

Investment in EJ Community Key:
* = Can address EJ communities depending on location of project
X = Addresses EJ communities
P = Program where some areas of the program will occur in EJ communities

3

4 Detailed analyses based on historical data, engineering assessments, and field
5 feedback was used to quantify each investment's benefits within each impact
6 dimension. The quantified benefits were then compared to the investment's costs

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to derive benefit-cost[14] ratios used to determine the relative difference between projects.

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

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

Dimensions which align with core safety and reliability improvements, such as Reduce Electric Hazards, one of the Company's most important impact dimensions, are given the highest weight of 3. This effectively means that a score of 100 in a lower weighted dimension will not be worth as much as a 100 rating in Reduce Electrical Hazards, the highest weight. For example, if a project's Reduce

[14] As noted above the GPM does not convert all benefits to dollars as is done in traditional BCAs.

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Electrical Hazards score is 50 (on a 0-100 scale), it will be multiplied by a weighting factor of 3 to receive a score of 150. A project with a Capacity Expansion score of 50 will be multiplied by the weighting of 2 and contribute 100 to the total scoring. This example illustrates how the impact dimension weights will rank projects higher if they provide benefits in dimensions with higher weightings. Once a program's index scores have been calculated across all impact dimensions and adjusted by weight, the index scores are summed together to determine the program's overall score. The higher the score, the better the GPM ranking.

Q42. Does the Company use other analysis to enhance the GPM prioritization methodology?

A42. Yes, the Company uses the BCA results to complement GPM results when a BCA has been performed for that investment.

Q43. How do the BCA results complement the GPM ranking?

A43. While the GPM remains our primary prioritization tool, BCA results guide our investment decisions and can be summarized into five general scenarios:

1) <u>The investment is a project and no BCA has been performed</u>: Projects where most of the benefits are not meaningfully captured through monetized reliability or cost-avoidance metrics, such as system loading projects which relieve capacity constraints, did not undergo a BCA and the BCR would not provide an informative measure of value. The project's priority is determined using the GPM score.
2) <u>A project has a BCR >0.9</u>: In this case the BCR results confirm monetized benefits approach or exceed project costs, and the projects generally deliver

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additional benefits not included in the BCR. Both the GPM and BCR are considered together when prioritizing projects.

3) A project has a BCR < 0.9: In this case, BCA results alone are not sufficient to justify the investment. In these instances, DTE Electric evaluates whether the project provides substantial benefits in GPM dimensions that are not captured in the BCA. If these benefits are not significant, the timing and the scope of the project may be reconsidered.

4) Overhead Reliability Programs: For certain reliability programs, BCAs provide insight that complements — but they do not replace — the GPM. While the GPM produces an overall program-level score, the BCA helps quantify how much of the program's investment delivers monetized benefits that exceed costs. For example, the PTMM BCA demonstrates that significant portions of the system yield BCRs above 0.9. Although PTMM is executed systemwide for safety reasons regardless of BCR, the results support a larger scale of PTMM investment than prior plans. Similarly, for Distribution Automation, BCR results help inform the total scope of investment under current assumptions. In addition to informing investment levels, circuit-level BCRs are used in annual planning.

5) Asset Replacement Programs: For asset replacement programs, BCA results determine the overall long term potential investment but they do not fully capture the value associated with addressing asset condition risk. Equipment health assessments consider factors beyond reliability and cost avoidance, and, as a result, BCAs represent only one input into replacement planning. Over time, BCAs will inform prioritization of specific asset replacements, but they

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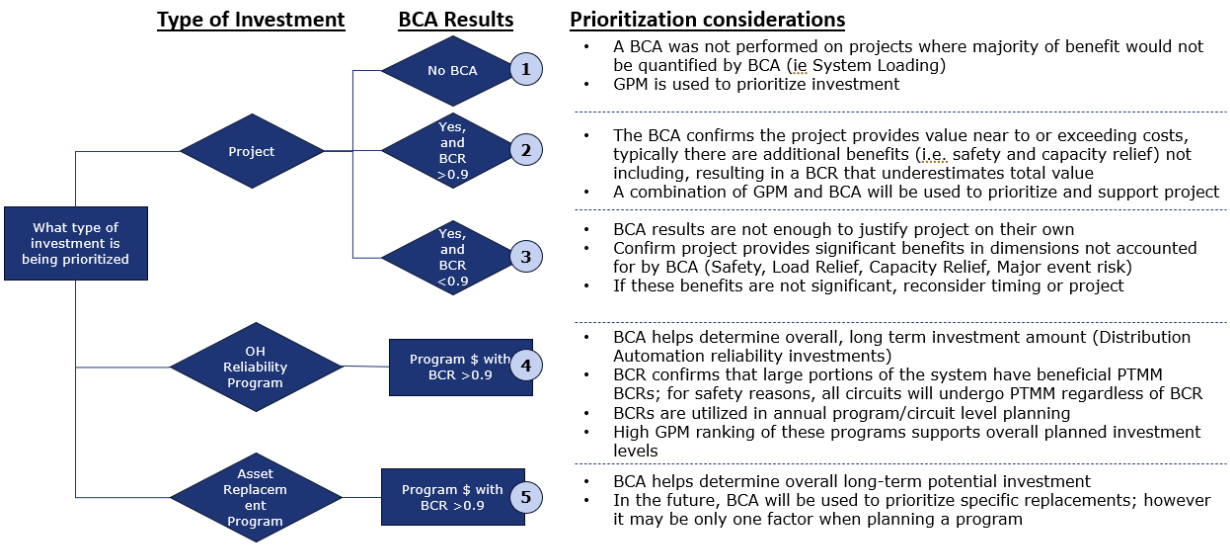
are applied alongside GPM results and engineering judgement rather than used in isolation.

A summary flow chart of how BCAs and the GPM interact in prioritization decisions is shown below in Figure 1.

Figure 1. **BCA** Prioritization Considerations and Interaction with the GPM



Q44. How do the GPM results support the Company's distribution investment decisions?

A44. The Company uses the GPM as the overarching framework to prioritize grid investments to select the highest relative benefit projects that will have the greatest impact improving the grid and the overall customer experience. Projects and programs are analyzed and ranked using the GPM on an annual basis. Investments

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that score highest in the GPM rankings are the ones that are generally selected for the Company's distribution infrastructure strategic investment plan. As described in detail below, there are some projects that are chosen outside of the GPM process or lower ranked projects within the process that are funded for various specific operational reasons.

Projects and programs that span multiple years are evaluated every year and may experience a change in GPM ranking if additional information modifies the expected project costs or benefits. However, to keep scoring relatively consistent year over year, the entire project cost as well as project benefits are still used when scoring the project, although the project costs and benefits will be adjusted for known changes (examples include cost changes, or increased benefits).

Q45. What are the GPM scores for the projects and programs proposed in this case?

A45. The total GPM scores for strategic projects and programs, ranked from highest to lowest, are illustrated in Figure 2. In addition, Table 4 lists the top 50 strategic projects and programs by name in rank order. GPM scores for all projects and programs, including scores for each of the 8 impact dimensions, are included in Exhibit A-23 M8 GPM Project and Program Rankings.

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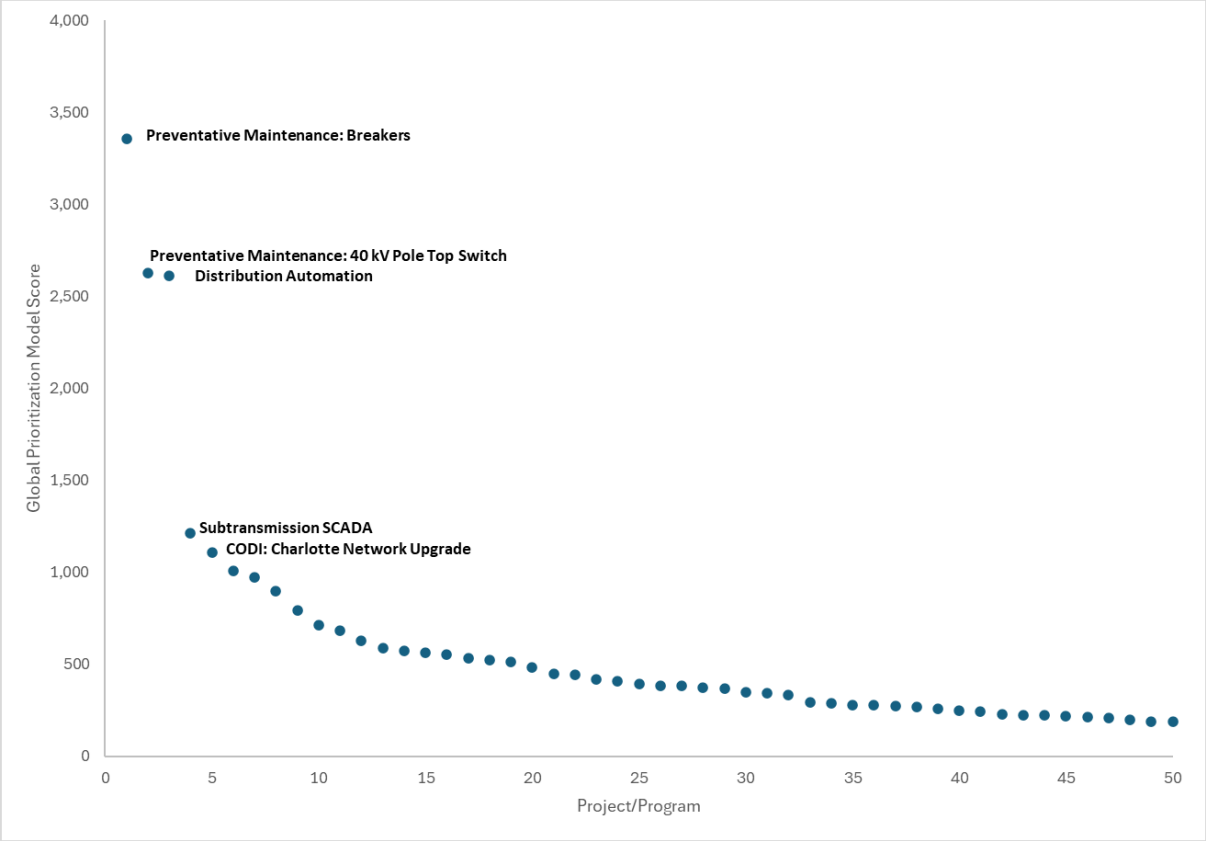
No.

1 **Figure 2. Overall GPM Scores for top 50 strategic programs and projects**



Line No.

1 **Table 4 Top 50 Strategic Programs and Projects Based on GPM**

Rank	Program/Project	Rank	Program/Project
1	Preventative Maintenance: Breakers	26	CODI: Howard Conversion
2	Preventative Maintenance: 40 kV Pole Top Switch	27	4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade)
3	Distribution Automation	28	4.8 kV CC: Hawthorne Relief and Circuit
4	Substransmission SCADA	29	Subtransmission Redesign & Rebuild: Hurst
5	CODI: Charlotte Network Upgrade	30	4.8 kV CC: Grosse Pointe Substation and Circuit Conversion - South
6	Preventative Maintenance: Distribution Remote	31	Substation Risk: Chestnut
7	Vegetation Management	32	Subtransmission Redesign & Rebuild: Bernard
8	Preventative Maintenance: OH Capacitor and	33	URD Replacement Program
9	Preventative Maintenance: URD Transformers	34	System Loading: Otsego/Capac/Shaw
10	4.8 kV Hardening	35	Substation Risk: Hood
11	NWA: Port Austin Load Relief	36	4.8 kV CC: Calla Circuit Conversion and Phase 2
12	40 kV: Automatic Pole-Top Switch	37	CODI: Kent/Gibson Conversion
13	Substation Risk: Seville	38	4.8 kV CC Barber Substation and Circuit Conversion
14	Subtransmission Redesign & Rebuild: Sandusky Transformer 101 Breaker	39	Substation Risk: Belleville Switchgear Decommission
15	CODI: Amsterdam Conversion Initiative	40	Subtransmission Redesign & Rebuild: Badax Transformer 102 Addition
16	CODI: Garfield Network Upgrade	41	4.8 kV CC: Birmingham Decommissioning and Circuit Conversion
17	Subtransmission Redesign & Rebuild: Trunk 3509	42	CODI: Islandview Substation
18	CODI: Alfred Substation Expansion	43	4.8 kV CC: Melvindale
19	Pole and Pole Top Maintenance and Modernization (PTMM)	44	NWA: Veridian
20	Frequent Outage Program (CEMI)	45	4.8 kV CC: Hilton Substation and Circuit Conversion
21	Cable Replacement Program	46	4.8 kV CC: SCOTN
22	CODI: Targeted Network Secondary Cable	47	4.8 kV CC: ISO Conversion Program
23	Subtransmission Redesign & Rebuild: Trunk 4266	48	Substation Risk: Apache
24	4.8 kV CC: Zenon Substation and Circuit Conversion - Phase 2	49	Breaker Replacement Program
25	8.3 kV CC: Pontiac Overhead/Underground Conversion	50	Subtransmission Redesign & Rebuild: Trunk 4911

2

3 **Q46. Are there other factors besides the GPM ranking that could impact the final**
4 **project and program selection and timing?**

5 A46. Yes. While the benefit-cost scores of programs and projects and their prioritization
6 ranking provide the foundation for the Company's strategic investment decisions,

Line No.

1 there are other considerations that could impact project selection and timing, as
2 listed below:

3 • Safety issues that cannot be easily quantified and indexed could warrant an
4 investment regardless of the scoring within the GPM model to protect our
5 customers or employees. For instance, subtransmission disconnect switches
6 and the Pontiac vault projects are necessary to meet operational safety
7 needs.

8 • Investment timing for programs and projects considers the impact on
9 workforce needs. Resources required for engineering, design, project
10 management, scheduling, and construction need to be evaluated not only by
11 project type (substation, overhead or underground) but also by geographic
12 location. Resource gaps and balancing are evaluated before project
13 sequencing decisions are made. Investment decisions also consider the
14 Company's capacity to perform the work, as the Company often partners
15 with third parties to plan and execute projects as noted above in Part I.

16 • System operational constraints and stability, occasionally including
17 transmission, can cause the Company to adjust the timing of a project. For
18 example, a project may be needed to address subtransmission system
19 integrity caused by load growth.

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

Line No.

- Pilot projects may be pursued independently of how they score and rank in the GPM as they are used to determine what the expected benefits and cost may be to complete an activity that the Company believes could be beneficial to its customers. In other words, the pilots help provide the data for a more adequate accounting of potential future project benefits. An example is non-wire alternative ("NWA") projects. These NWA pilot projects focus on using alternative technologies to address circuit or substation overload concerns to help delay or offset traditional grid upgrade investments. These pilots are supported by Witness Stowe and details are provided in Exhibit A-12 Schedule B5.4.1 through B5.4.7. Future pilots would be considered through the Commission's expedited pilot process.
- Capital projects are subject to certain development and execution risks in the conceptual design and early development stages, including land availability and property purchases, municipal approvals and construction permits, right-of-way acquisition and easements, and lead times when procuring major equipment. While the Company takes proactive measures to mitigate these execution risks, many of these early-stage developments are difficult for the Company to control and can introduce schedule delays or cost increases. Therefore, the Company's investment and maintenance plan is designed to include some flexibility to accommodate these unpredictable variations in timing and cost.
- Some capital replacement programs are funded annually to avoid acceleration of asset failures and the risk that a large quantity of assets would reach end-of-life concurrently, thus exceeding available resources to replace them (e.g., the underground residential distribution cable program).

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- If the Company is awarded grant money from the state or federal government for specific projects, it could impact project selection due to grant project completion requirements.
- Projects already in active construction are prioritized.
- Some Operational Technology ("OT") projects are not evaluated through the GPM, as the GPM is largely designed for investments which upgrade the physical distribution grid. The specific benefits which OT projects deliver are discussed in more detail in Witness Rademacher's testimony.
- BCA results could lead to reconsideration of investments within the GPM and are discussed more thoroughly above.

It is important to note that some programs and projects may not be funded in a particular year due to lower benefit-cost scores relative to other projects. All the programs and projects identified by the Company and evaluated by the GPM provide system improvements and benefits to customers and may be funded at some point over the next several years. While the strategic capital investment plan is primarily driven by the GPM, the Company may adjust the annual plans based on changing circumstances and grid needs.

Q47. Do the GPM scores and rankings have the potential to change over time?

A47. Yes. As the Company continues to make investments in distribution infrastructure, the benefits of capital investment are examined on a regular basis and the GPM scores may change over time as new data becomes available, and the prioritization ranking of the programs and projects may change accordingly. The addition of new programs and projects to the GPM can also change the rankings. As the

Line No.

Commission acknowledged in its 2024 Order, the Company's top 50 list and the associated cost estimates are not static.[15]

PART III: Reliability Model

Q48. What is the Company's Reliability Model and what is its purpose?

A48. The reliability model uses the strategic capital plan, historical performance, and circuit conditions for the purpose of forecasting, by year, the reliability performance (outage events, SAIDI, and SAIFI) of the DTE Electric system in typical weather with higher and lower projections for severe and mild weather scenarios. Alongside the GPM and BCA tools, the Reliability Model is an important vehicle for evaluating the overall impact of capital investments to ensure that the Company is delivering high levels of value and impact for customers.

Q49. Has the Company made any changes to its reliability model since case U-21860?

A49. Yes. Since case U-21860, the Company has replaced its Excel-based reliability model with a new statistically and algorithmically based model. The Company led the architecture and overall model design and leveraged an expert third-party developer, E Source, to code and enhance the model. This updated approach provides improved projections, incorporates additional programs, and is better equipped to run scenario analysis.

Q50. Please describe the Company's new Reliability Model.

[15] Case No. U-21534 January 23, 2025 Order pg. 97

Line No.

A50. At the conceptual level, the new Reliability Model operates on similar principles to the previous Excel-based model. The Reliability Model remains an analytical tool that estimates tangible reliability improvements associated with proposed capital investments in a data-driven framework on a circuit-by-circuit basis. See Exhibit A-23 Schedule M7 for an output of the reliability model results. The model calculates improvements from investment programs and projects based on industry-standard performance metrics and includes an adjustment for post-investment degradation over time, providing a way to numerically estimate the reliability benefits that the proposed projects will provide.

However, the new Reliability Model is more sophisticated in several important ways. First, the new model uses a circuit- and substation-based approach to develop the baseline. Second, the model forecasts reliability, using a bottom-up approach, modeling five distinct parts of the electrical system individually. For the remaining testimony, these different parts of the system will be referred to as "sections" of the electrical system. Specifically, these sections of the system are overhead distribution, underground distribution, subtransmission, substation, and secondary. Third, the model leverages satellite-images, LIDAR data, and conductor data to calculate tree strike risks on a circuit-by-circuit basis. Fourth, the model also forecasts reliability performance by severe weather, typical weather, and mild weather scenarios.

Q51. How does the Company calculate reliability improvement projections in the new Reliability Model?

Line No.

A51. The process to project reliability performance within the model can be summarized in five steps:

1) **Determine the Baseline:** The reliability calculations are performed on the five sections of the electrical system separately because each investment program has targeted benefits applied to each section. Each section uses historical performance, specific circuit or substation risk profiles, and weather severity to forecast baseline performance at a circuit and substation level that reflects the evolving nature of the system performance based on the most recent investment impacts.
2) **Calculate Program Effectiveness:** Estimate impact the modeled reliability programs would have if an asset undergoes an investment, generally calculated as a percent reduction in event volume or a reduction in customer interruptions and customer minutes per event.
3) **Apply Proposed Investment Plan and Degradation to Event Volume:** Next, the model applies the estimated impact of planned investments, as well as degradation, on each section of the system and results in a projected outage event counts at circuit and substation level.
4) **Calculate Total Customer Interruptions:** After events are determined, the model calculates average customer interruptions per event by weather scenario, the average number of customer interruptions varies by section of the system (i.e. the average number of interruptions for a substation outage is different than for a secondary system outage). Using this data, the model calculates the total customer interruptions by section, summing these interruptions to a system level provides the models SAIFI forecast.

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1 **5) Calculate Customer Outage Minutes:** The model multiplies the average
2 CAIDI by customer interruptions to calculate total outage minutes.
3 Each of these steps is described briefly below.
4
5 **Q52. How is the starting point, or baseline, calculated?**
6 A52. Each section of the system, down to a circuit or substation level has its own baseline
7 of forecasted reliability performance assuming no investments. This baseline is
8 modeled from historical outages (2021-2025) and system degradation which
9 allowed the Company to incorporate the most recent reliability data unlike the
10 previous model which was anchored to a baseline of 2018-2022. It also incorporates
11 circuit and substation risk profiles using specific characteristics including, circuit
12 voltage, circuit length, tree strike risk, asset age, circuit phase configuration, and
13 conductor material. Separate baselines are calculated for different weather
14 scenarios (mild, typical, severe).
15
16 **Q53. Which reliability investments are included in the model?**
17 A53. The model accounts for reliability improvements from the following investment
18 programs: Vegetation Management, 4.8kV Hardening, PTMM (both pole work and
19 pole-top work), 4.8kV Conversion, Distribution Automation, substation equipment
20 replacement (Switchgear, Breaker), Small Wire, Undergrounding, and URD Cable
21 Replacement.
22
23 **Q54. How does the Company estimate the effectiveness of the reliability**
24 **investments?**

Line No.

A54. Of the investment programs included in the reliability model, three utilize historical data to evaluate effectiveness. These programs are Vegetation Management, 4.8kV Hardening, and PTMM. The method to establish effectiveness begins by setting baseline non-MED circuit performance for years prior to the reliability improvement being deployed. Non-MED event data for years post deployment is compared to the baseline to calculate the reliability improvement. The year the investment is made is not used in the effectiveness analysis as the timing of the work being completed could impact in-year performance. For example, if PTMM is performed in January, reliability improvement would be expected for most of the year. If it were performed in December, little improvement would be expected that year. For all other programs, the reliability improvement is based either on the assessment from results from the 1898&Co. BCA work, industry subject matter experts, including DTE Electric's Engineering, by comparing the newer program to similar established programs, or by using a smaller subset of circuit outage data. Effectiveness analyses is presented in Exhibit A-23 Schedule M19 and includes reliability performance results from 2025 in the analysis.

Q55. How are the program effectiveness results applied within the model?

A55. In the model, investments effectiveness is applied to the type of event that is likely to be influenced by that investment. For example, if a circuit has vegetation management planned, the model will project a reduction in tree-related outage events to the subtransmission, overhead distribution, and/or secondary as appropriate.

Line No.

Q56. How does the model project outage events using historical baseline forecasts and program effectiveness?

A56. The proposed investment plan by program and project is entered into the model. For example, the model incorporates the PTMM work in 2026 that aligns with the Company's investment plan. Sections of the systems, by circuit or substation, will have program effectiveness benefits applied to the circuit or substation baseline which will reduce the future volume of events within the model. Half of the full year benefit will be applied in the year of the investment, with the assumption that some investments will occur early in the year and some later in the year and, on average, projects will be constructed and useful for half of the year. The full year benefit is then applied in the first year after the investment. The benefit will decrease over time due to factors such as the regrowth of trees, and the continued degradation and aging of electric system equipment. The model projects that rebuild work provided by 4.8kV Conversion will deliver a consistent benefit for 10 years after investment without any degradation. The impact of the Distribution Automation investment is a reduction in the CI/CMI per event on the circuit, but there is no associated reduction in event volume. If a section has no planned investment, the model will calculate an increase in future event volume, or degradation, over time. This is because the section of the system is assumed to degrade over time without inspection and/or periodic replacement. Once program effectiveness and degradation is applied to all section circuits and substations with and without investment, total forecasted events are determined and can be summed at a circuit, substation, section, or overall system level.

Line No.

Q57. How does the Reliability Model translate outage events into customer interruptions (SAIFI)?

A57. Using historical outage data, the model calculates average customer interruptions per event by section. Different average customer interruptions are determined by weather severity (mild, typical, and severe). For example, an average subtransmission outage is forecast to be much larger than an average secondary outage. Additionally, an average outage within subtransmission is larger in severe weather compared to mild weather forecasts.

The model calculates the total customer interruptions by section by multiplying number of events by the average number of customer interruptions per event by section type. Summing up these interruptions to a system level provides total interruptions on an annual basis which is then divided by total system customers to determine a system SAIFI forecast.

Q58. How does the Reliability Model forecast total outage minutes (SAIDI)?

A58. The model calculates average regional restoration time by weather scenario. DTE Electric has four different operational regions, Northwest (NW), Northeast (NE), Southwest (SW), and Southeast (SE). Each of these regions has different characteristics that influence outage restoration times. For example, SE contains the City of Detroit as well as a large amount of the surrounding urban and suburban communities (Dearborn, Royal Oak, etc.). As such, crew drive times can be shorter but older infrastructure and backyard placement can affect restoration. By comparison, NE contains the Thumb region which can have long crew drive times but have the advantage of equipment that is often located on the roadside. Because

Line No.

of these differences, regional CAIDI forecasts were determined to be more accurate than a system wide CAIDI forecast. CAIDI forecasts are not separated by section, all sections within a region assume the same regional CAIDI forecast.

The model multiplies the regional CAIDI by regional customer interruptions to calculate the outage minutes for each region to determine total outage minutes. Total system wide outage minutes are divided by total system customers to determine the forecasted system SAIDI on an annual basis.

Q59. Does the Company use the projected event reductions from the Reliability Model to determine emergent cost saving from strategic investments?

A59. Yes. The Reliability Model is used to project emergent cost reductions, shown in Exhibit A-12, Schedule B5.4 Revised, page 1, line 6, based on the projection of the number events reduced due to modelled investments.

Q60. Turning to the results of the model, based on DO investments proposed in this case, what system reliability improvements are expected?

A60. The Company's Reliability Model projects that customers are expected to experience an improvement in all-weather SAIDI of 17 minutes in 2026, 61 minutes in 2027, and 114 minutes in 2028, compared to a scenario with no strategic investment, assuming typical weather. Similarly, all-weather SAIFI will be 0.03 better in 2026, 0.12 better in 2027, and 0.22 better in 2028 compared to a scenario with no strategic investment and typical weather. Graphs of expected reliability benefits through 2030 are shown in Figure 3. Note that these projections are the most likely outcome according to the model but include a range of possibilities to

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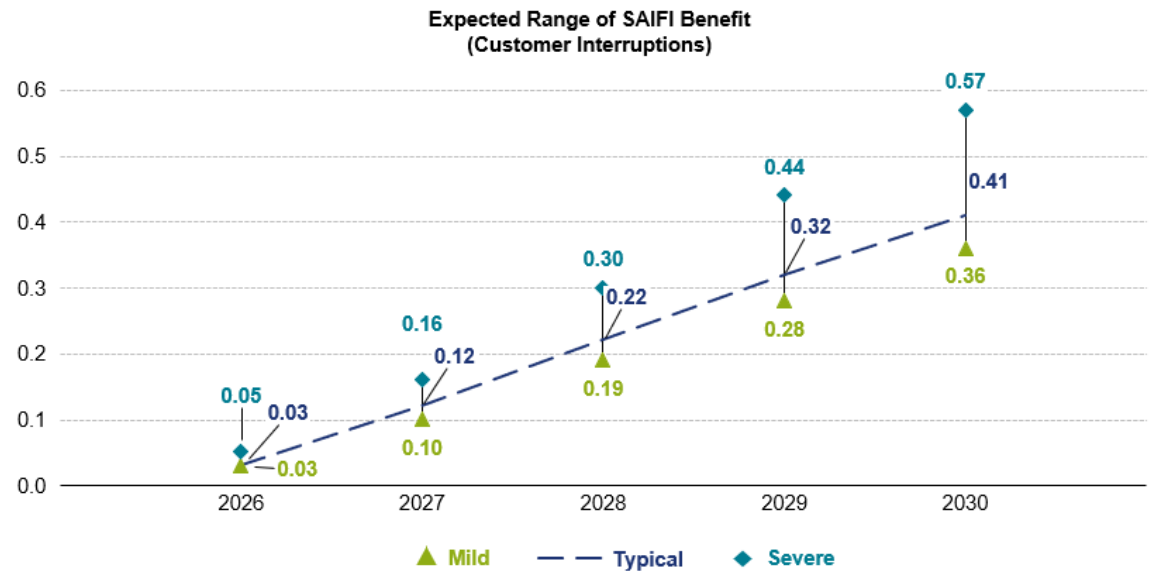
No.

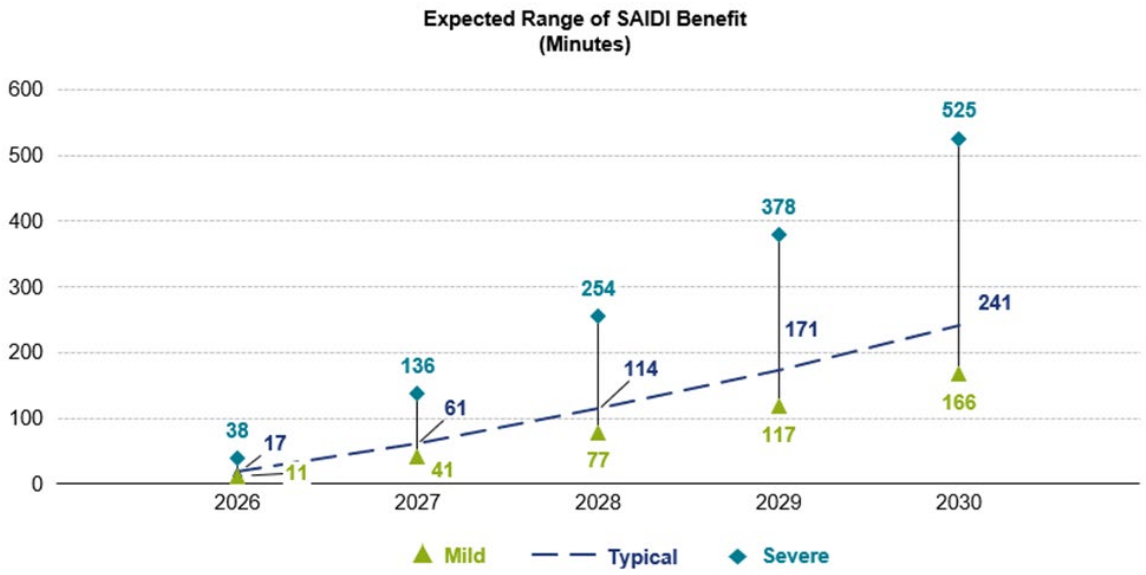
1 account for both favorable and unfavorable weather variability year to year.
2 Specific reliability projections at the circuit and system level are provided in
3 Exhibit A-23 Schedule M7 and the Reliability Model technical paper in the 2026
4 DSP.

Line No.

1 **Figure 3. Cumulative Reliability Benefits of DSP Investments For All-Weather**

2 **Conditions Across Three Reliability Scenarios[16]**





3

4 **Q61. Does the Company believe that the new Reliability Model results are an**

5 **improvement compared to the model submitted in previous cases?**

[16] Cumulative annual benefit is derived from comparing the DSP investment Reliability Model results, which includes the bridge year and test year investments requested in this case, against results without strategic or Vegetation Management investments.

Line No.

A61. Yes. The new model is more sophisticated and more analytically rigorous than its predecessor. The new model analyzes conditions by sections of distribution network (Distribution overhead, Distribution underground, Substation, Subtransmission, Secondary) before summing up to the system. This approach takes into consideration characteristics of different sections of the network. For example, it uses a broader set of relevant variables by section, such as overhead and underground conductor length, voltage type, historical outages, weather severity, tree strike risk to calculate the baseline performance by section. Additionally, the new model incorporates the characteristics by operational regions into the modeling. Finally, the new model applies investment plan by circuit and program effectiveness applicable to the section of the network to develop a more robust forecast for reliability performance when compared to the previous model.

PART IV: Model Transparency

Q62. How does the Company plan to support transparency for the BCA and the Reliability Model?

A62. Mirroring Witness Chiu transparency approach for BCA models, for the reliability model, the Company has provided a technical paper in the 2026 DSP, detailing the model's construction, inputs, outputs, as well as an excel output of detailed baseline and forecast data by circuit. The Company plans to discuss the modeling methodology at a technical conference post rate case filing and will offer subsequent model navigation sessions for those interested in reviewing the model at a more granular level.[17] See **Figure 4** for an overview of the process.

[17] Participation in the technical conference and access to proprietary and confidential Reliability Model design information will require an NDA and adherence to CEII protections, as described further below.

Line No.

1 **Figure 4. Approach to Providing Transparency for the Reliability**
2 **Model[18]**

Step	Activity	Description	Requirements
1	Technical report on Reliability Model	• Detailed write up of Reliability Model results quantifying expected reliability benefits from DSP investments using data-driven statistical modeling	• N/A – appendix in 2026 DSP filing
2	Technical Conference – Reliability Model Overview	• One-day walk-through of model design, functions, and data input/assumptions	• Recommended pre-read of the technical report • Parts of Conference may require NDA or CEII
3	Model Navigation Sessions – Virtual model navigation and tutoring	• Half-day intervenor sessions with E-source and DTE to grant virtual model access via E-source screensharing, with assistance navigating and clicking through the model	• Required technical conference attendance • 8 business days advance request, matching A&D timeline • CEII agreement required

3

4 **Q63. How does the Company anticipate structuring the technical conferences?**

5 A63. The Company anticipates organizing the technical conferences on a topical basis,
6 such as a Reliability Model overview or BCA methodology walkthrough. All
7 eligible parties would be invited to attend each session.

8

9 **Q64. For both the BCA models and the new Reliability Model, why is the Company**
10 **proposing optional model navigation sessions in connection with this case?**

11 A64. In recent proceedings, including Case No. U-21860, the Commission and parties
12 have emphasized the importance of transparency regarding distribution system
13 modeling and benefit-cost analysis, and the Company recognizes that a shared
14 understanding of these tools supports informed evaluation of its investment

[18] See direct testimony of Witness Chiu regarding the similar approach on the detail defined steps for providing additional transparency for the BCA.

Line No.

proposals. Additionally, parties have emphasized the need for increasingly rigorous and complex distribution system modeling. In response to this feedback, the Company has shifted toward greater sophistication in modeling approach and more powerful modeling platforms that exceed capabilities of more simplistic, Excel-based models.

The proposed model navigation sessions are intended to allow interested parties a full and complete review of the model without compromising the security and/or intellectual property of the Company's vendors and not requiring stakeholder to purchase and install expensive software and pay for access to power computer servers to host the models.

Q65. Who would be eligible to participate in the technical sessions?

A65. Participation would be open to any party in this proceeding that has executed a non-disclosure certification under the Commission approved Protective Order in this case. The model navigation sessions may reference Critical Energy Infrastructure Information ("CEII"), confidential system data, or protected modeling inputs that were submitted under seal in this case.

PART V: Environmental Justice

EJ Definitions and Geographic Representations

Q66. How does the Company define environmental justice?

A66. The Company defines environmental justice (EJ) in the context of the State of Michigan's MiEJ Screening tool[19] definition of environmental justice as "the

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

Line No.

1 equitable treatment and meaningful involvement of all people, regardless of race,
2 color, national origin, ability, or income in the development and application of laws,
3 regulations, and policies that affect the environment, as well as the places people
4 live, work, play, worship, and learn."[20]
5
6 **Q67. How has DTE Electric Distribution Operations defined a vulnerable**
7 **community for use with the MiEJScreen Tool?**
8 A67. An 80% threshold definition was adopted for vulnerable communities using the
9 MiEJScreen Tool score, consistent with the previously available U.S. EPA
10 EJScreen tool.[21] Following this approach, census tracts with a MiEJScreen
11 composite score at or above the 80th percentile are considered vulnerable
12 communities for the purpose of this testimony and associated analysis. The
13 MiEJScreen composite score is calculated using categories and indicators for
14 environmental and census population data as shown in Figure 5 below. On
15 November 18, 2022, the Commission directed its Energy Affordability and
16 Accessibility Collaborative to address definitions of terms such as environmental
17 justice, grid equity, and energy justice (Case No. U-20836, November 18, 2022
18 Order, pp. 461-464).

[20] State of Michigan, Department of Environment, Great Lakes, and Energy, https://www.michigan.gov/egle/public/learn/environmental-justice, accessed March 18, 2025.
[21] EPA, EJScreen Technical Documentation for Version 2.3, accessed March 19, 2025.

Line No.

1 **Figure 5. MiEJScreen Overall Score Calculation**

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

2

3 **Q68. Is the Company able to provide a geographic representation of 2025 electric**
4 **reliability data by census tracts?**

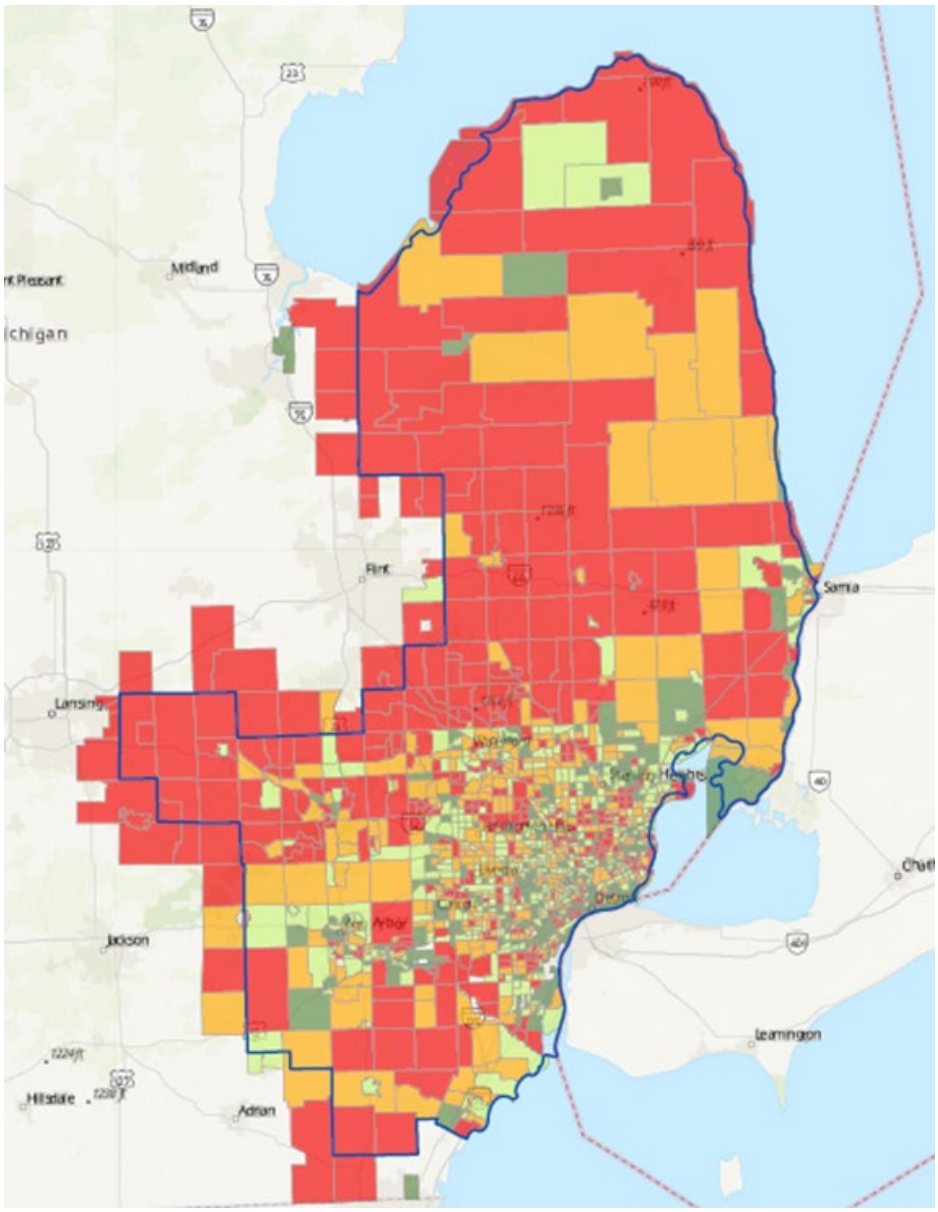
5 A68. Yes. Using the residential customer meters that are matched to census tracts, DTE
6 Electric developed reliability data for SAIFI and SAIDI by census tract and grouped
7 the data into DTE Electric reliability quartiles, with first quartile customers (shown
8 below in green) experiencing the best reliability and fourth quartile customers
9 (shown below in red) experiencing the worst reliability. Looking specifically at
10 outage frequency, first quartile reliability customers have a 2025 All-Weather
11 SAIFI performance of fewer than 0.42 interruptions, second quartile customers
12 range between 0.42 and 0.91 interruptions, third quartile customers are between
13 0.91 and 1.55 interruptions, and fourth quartile customers have performance greater
14 than 1.55 interruptions. Looking at outage duration, first quartile reliability

Line No.

customers have a 2025 All-Weather SAIDI performance less than 52 minutes, second quartile customers range between 52 and 114 minutes, third quartile customers are between 114 minutes and 233 minutes, and fourth quartile customers have experienced outage duration above 233 minutes. Maps for SAIFI and SAIDI by census tract are included in Figure 6 to Figure 9. Note that mapping can visually skew how the reliability of EJ and other communities is represented, because census tracts aren't equal in size and population, i.e. a smaller densely populated census tract can look less impactful than a larger, lower density census tract.

Line
No.

1 **Figure 6. 2025 All Weather SAIFI by Census Tract in the DTE Service Area**

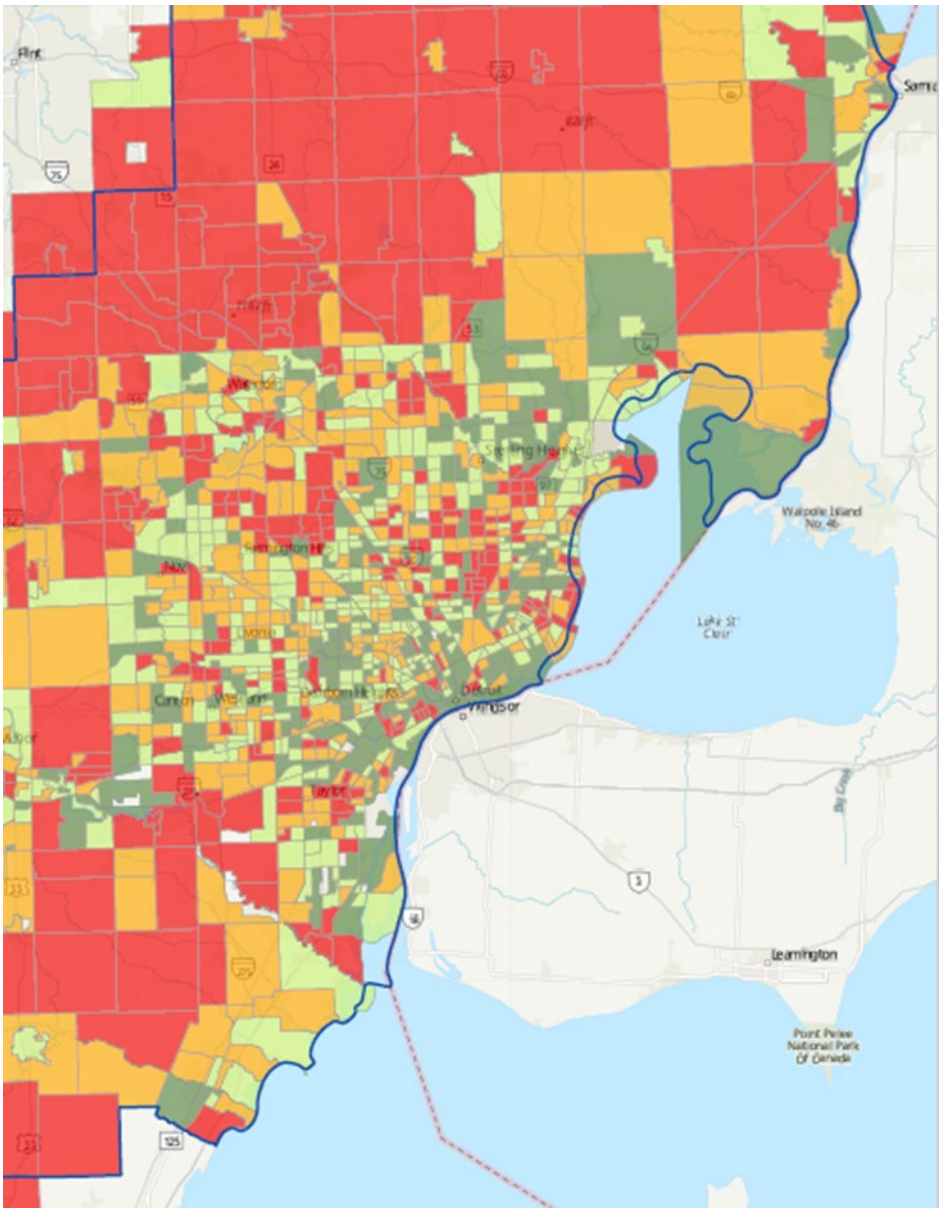


2

Quartile SAIFI	
	Q1 <= 0.42
	0.42 < Q2 ≤ 0.91
	0.91 < Q3 ≤ 1.55
	Q4 > 1.55

Line
No.

1 **Figure 7. 2025 All Weather SAIFI by Census Tract for Metro Detroit Area**

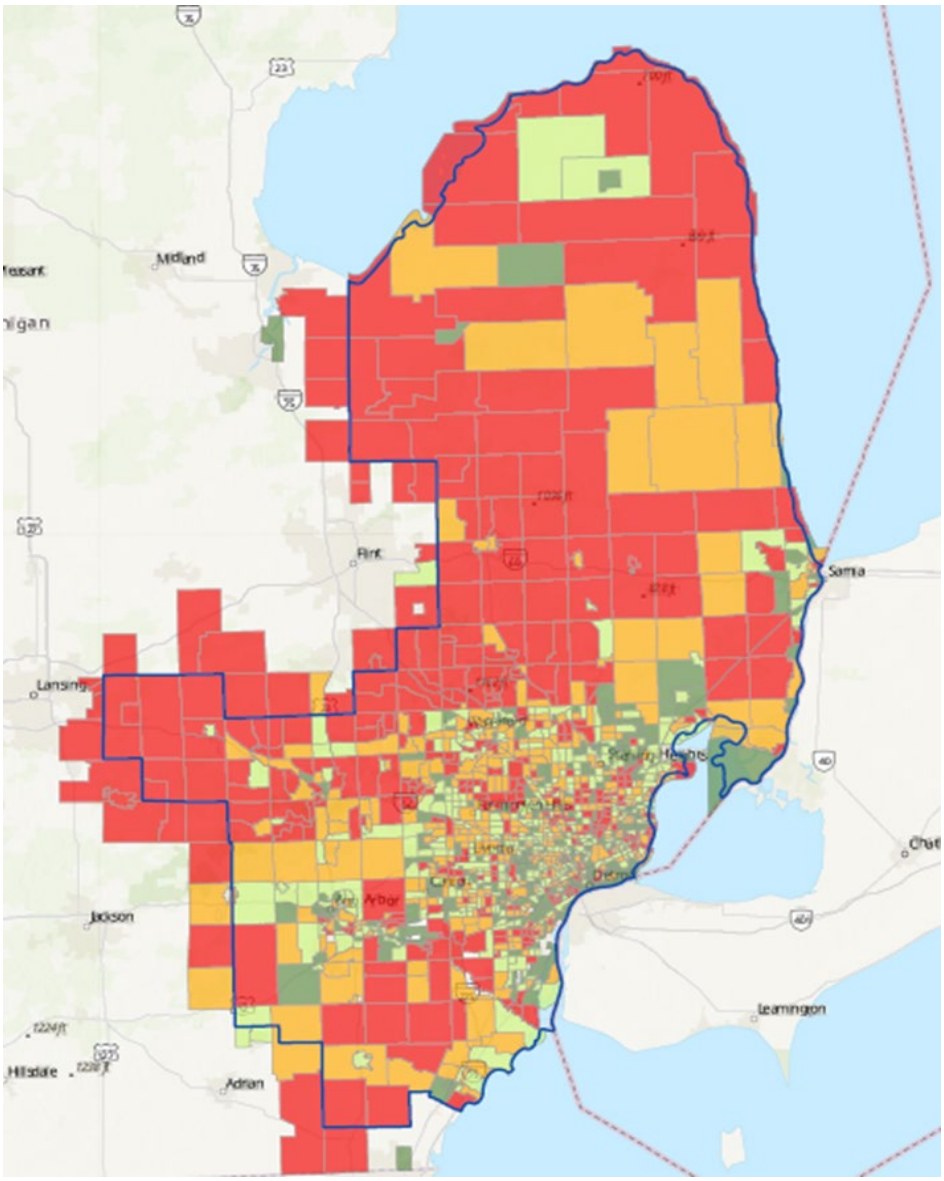


2

Quartile SAIFI	
	Q1 <= 0.42
	0.42 < Q2 ≤ 0.91
	0.91 < Q3 ≤ 1.55
	Q4 > 1.55

Line
No.

1 **Figure 8. 2025 All Weather SAIDI by Census Tract in the DTE Service Area**

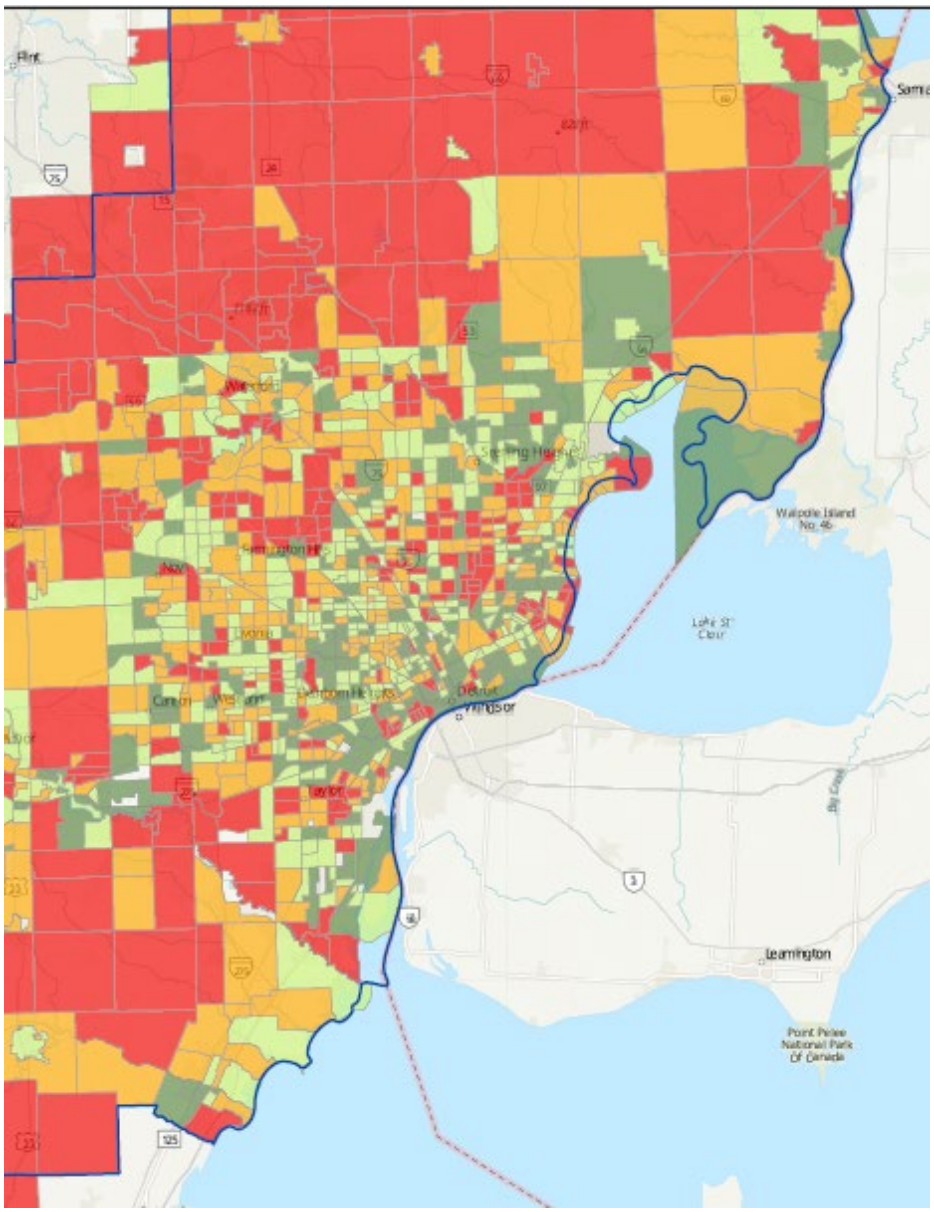


2

Quartile SAIDI	
	Q1 <= 52
	52 < Q2 ≤ 114
	114 < Q3 ≤ 223
	Q4 > 223

Line
No.

1 **Figure 9. 2025 All Weather SAIDI by Census Tract for Metro Detroit Area**



2

Quartile SAIDI	
	Q1 <= 52
	52 < Q2 ≤ 114
	114 < Q3 ≤ 223
	Q4 > 223

Line No.

1 **EJ in Grid Planning**

2 **Q69. How does DTE Electric incorporate EJ in grid planning?**

3 A69. Building on previous plans, in the 2026 DSP[22] the Company refined three core EJ
4 objectives:
5 (1) incorporate EJ considerations in investment and planning prioritization by
6 including an EJ component in the GPM and other decision-support tools, which I
7 discuss in this section of testimony below and above in Part 2: GPM.
8 (2) improve system performance for vulnerable communities experiencing
9 historically poor reliability through our targeted investment programs, which I will
10 describe here, and
11 (3) enhance support to vulnerable customers during outage events through
12 strengthened community outreach efforts, which is described in the Third-Party and
13 Community Outreach section of the 2026 DSP.
14

15 **Q70. In addition to the use of the EJ multiplier in the GPM, how else is the EJ**
16 **multiplier impacting the Company's investment decisions?**

17 A70. The Company is using an EJ Multiplier, calculated in the same way as the GPM EJ
18 multiplier discussed in the GPM testimony section, to adjust benefit cost ratios used
19 for prioritizing circuits within the PTMM and Distribution Automation Programs
20 in the 2026 investment plan. The Company has also used the EJ multiplier as an
21 input to PTMM and Distribution Automation circuit prioritization for the 2027-
22 2030 plans included in the Reliability Model and will be used for IRM circuit
23 prioritization. Witnesses Rademacher and Robinson discuss circuit prioritization
24 in their respective testimonies.

[22] Exhibit A-23 Schedule M1.

Line No.

1 **Q71. Has the Company evaluated how its investment programs have reached**
2 **vulnerable communities to improve electric distribution infrastructure and**
3 **reliability performance?**
4 A71. Yes. The Company has evaluated some of its largest distribution investment
5 projects and programs - 4.8kV Hardening, 4.8kV Conversion, and Vegetation
6 Management - with respect to if the investment was made in a vulnerable area.
7
8 The results are summarized in Table 5 and show how the Company's investments
9 are supporting vulnerable customers and communities in southeast Michigan,
10 including the City of Detroit. This analysis is based on the MiEJScreen Tool census
11 tract data and Company investment data on the circuits addressed by the following
12 three programs over the timeframe 2021-2025: 4.8kV Hardening, Vegetation
13 Management, and Conversions. For each of these investment programs, Table 5
14 shows total investment dollars by program, program investment in vulnerable
15 communities, and percentage of program investment in vulnerable communities.
16 For example, of the nearly half billion dollars investment in the 4.8kV Hardening
17 program since 2021, 86% of work performed under the Hardening program
18 occurred in vulnerable communities. As discussed by Witness Robinson, the
19 Hardening program has resulted in documented safety and reliability
20 improvements, including reduction in the frequency and duration of outages and
21 fewer downed wires, through the program's clearing of right of way, equipment
22 upgrades, and removal of arc wire.

Line No.

1 **Table 5 2021 to 2025 Investment in Vulnerable Communities**

2 **(Census Tracts with MiEJ Score of 80% to 100%)**

Investment Program (2021-2025)	Total Investment by Program ($millions)	Total Investment by Program in Vulnerable Census Tracts ($millions)	% Of Investment in Vulnerable Census Tracts
Conversion	$784	$455	**58%**
4.8kV Hardening	$542	$465	**86%**
Vegetation Management	$966	$227	**23%**

3

4 **Q72. How will the Company's planned 2026–2027 distribution investment**
5 **programs specifically support vulnerable communities, based on the execution**
6 **strategy outlined in this case?**

7 A72. To highlight investment in vulnerable communities, the Company focused on three
8 of the largest strategic investment programs. Witnesses Stowe, Robinson, and
9 Hutchinson address the Company's planned investments for 2026 and 2027 for
10 Conversions, Hardening, and Vegetation Management, respectively. Table 6
11 summarizes total investment dollars by program, total program investment in
12 vulnerable communities, and percentage of program investment in vulnerable
13 communities in 2026-2027.

14

15 **Table 6 2026-2027 Investment in Vulnerable Communities**

16 **(Census Tracts with MiEJ Score of 80% to 100%)**

Investment Program (2026-2027)	Total Investment by Program ($millions)	Total Investment by Program in Vulnerable Census Tracts ($millions)	% Of Investment in Vulnerable Census Tracts
Conversion	$397	$188	**47%**
4.8kV Hardening	$143	$116	**81%**
Vegetation Management	$360	$50	**14%**

Line No.

1 **Q73. Has the Company also analyzed investments in 5% EJ gradations?**

2 A73. Yes. The Company analyzed investments pertaining to Hardening, Vegetation
3 Management, and Conversion including CODI programs, to provide information in
4 EJ community gradations based on the MiEJScreen score as defined in the
5 December 2023 order in Case No. 21297. The gradations are defined as 0% to 5%,
6 >5% to 10%, in 5% gradations up to >95% - 100% of the MiEJScreen composite
7 score, the same as the reliability analysis above. Tables 7 to Table 12 below
8 demonstrate the Company's investment distribution by program for EJ gradations
9 by year.

10

11 Table 7 **Hardening Investments by EJ Gradations**

EJ Gradations	2021 Investment ($000)	2022 Investment ($000)	2023 Investment ($000)	2024 Investment ($000)	2025 Investment ($000)	2026 Investment Forecast ($000)	2027 Investment Forecast ($000)
0-5%	$ -	$ -	$ 1,710	$ -	$ 68	$ -	$ -
5-10%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10-15%	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,838
15-20%	$ -	$ -	$ -	$ -	$ 2	$ 0	$ -
20-25%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25-30%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
30-35%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
35-40%	$ -	$ 1,955	$ -	$ -	$ 8	$ -	$ 2,362
40-45%	$ -	$ -	$ -	$ -	$ -	$ -	$ 726
45-50%	$ -	$ -	$ -	$ -	$ 0	$ -	$ 1,897
50-55%	$ 6,284	$ -	$ -	$ -	$ 2	$ -	$ 1,680
55-60%	$ -	$ -	$ -	$ 289	$ (5)	$ -	$ 111
60-65%	$ 1,669	$ 9,026	$ -	$ -	$ 40	$ -	$ 22
65-70%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
70-75%	$ 3,032	$ 2,747	$ -	$ -	$ 1,463	$ 9,056	$ -
75-80%	$ 16,682	$ 1,691	$ 4,148	$ 273	$ 1,490	$ 11	$ -
80-85%	$ 646	$ 8,354	$ 12,660	$ 11,987	$ 2,224	$ 2,828	$ 6,759
85-90%	$ 8,858	$ 22,658	$ 32,545	$ 17,019	$ 23,724	$ 5,628	$ 6,492
90-95%	$ 13,563	$ 39,625	$ 24,866	$ 23,105	$ 34,302	$ 34,053	$ 19,187
95-100%	$ 12,315	$ 65,540	$ 40,755	$ 35,393	$ 32,981	$ 27,284	$ 13,547
Unmapped/Unscored	$ 2,313	$ 5,885	$ 10,326	$ 4,200	$ 4,055	$ 3,139	$ 6,751
Total Investment ($)	$ 65,362	$ 157,482	$ 127,010	$ 92,266	$ 100,353	$ 82,000	$ 61,370

Line No.

1 Table 8 **Percent of Hardening Investments by EJ Gradations**

EJ Gradations	2021 Investment (%)	2022 Investment (%)	2023 Investment (%)	2024 Investment (%)	2025 Investment (%)	2026 Investment Forecast (%)	2027 Investment Forecast (%)
0-5%	0%	0%	1%	0%	0%	0%	0%
5-10%	0%	0%	0%	0%	0%	0%	0%
10-15%	0%	0%	0%	0%	0%	0%	3%
15-20%	0%	0%	0%	0%	0%	0%	0%
20-25%	0%	0%	0%	0%	0%	0%	0%
25-30%	0%	0%	0%	0%	0%	0%	0%
30-35%	0%	0%	0%	0%	0%	0%	0%
35-40%	0%	1%	0%	0%	0%	0%	4%
40-45%	0%	0%	0%	0%	0%	0%	1%
45-50%	0%	0%	0%	0%	0%	0%	3%
50-55%	10%	0%	0%	0%	0%	0%	3%
55-60%	0%	0%	0%	0%	0%	0%	0%
60-65%	3%	6%	0%	0%	0%	0%	0%
65-70%	0%	0%	0%	0%	0%	0%	0%
70-75%	5%	2%	0%	0%	1%	11%	0%
75-80%	26%	1%	3%	0%	1%	0%	0%
80-85%	1%	5%	10%	13%	2%	3%	11%
85-90%	14%	14%	26%	18%	24%	7%	11%
90-95%	21%	25%	20%	25%	34%	42%	31%
95-100%	19%	42%	32%	38%	33%	33%	22%
Unmapped/Unscored	4%	4%	8%	5%	4%	4%	11%
Total Investment (%)	100%	100%	100%	100%	100%	100%	100%

2

3 **Table 9 Vegetation Management Investments by EJ Gradations**

EJ Gradations	2021 Investment ($000)	2022 Investment ($000)	2023 Investment ($000)	2024 Investment ($000)	2025 Investment ($000)	2026 Investment Forecast ($000)	2027 Investment Forecast ($000)
0-5%	$ 1,634	$ 3,055	$ 1,487	$ 547	$ 581	$ 78	$ 2,211
5-10%	$ 9,290	$ 4,653	$ 9,113	$ 2,978	$ 3,716	$ 8,056	$ 17,401
10-15%	$ 11,195	$ 12,626	$ 13,319	$ 4,167	$ 2,232	$ 5,281	$ 26,935
15-20%	$ 7,118	$ 6,069	$ 8,227	$ 5,178	$ 7,120	$ 2,962	$ 11,015
20-25%	$ 7,320	$ 11,946	$ 5,077	$ 8,194	$ 10,308	$ 7,448	$ 13,371
25-30%	$ 15,421	$ 12,696	$ 8,208	$ 8,287	$ 6,067	$ 8,114	$ 16,961
30-35%	$ 10,839	$ 16,395	$ 9,867	$ 4,576	$ 8,347	$ 10,170	$ 12,603
35-40%	$ 7,666	$ 15,467	$ 8,204	$ 3,557	$ 13,634	$ 10,086	$ 7,436
40-45%	$ 8,498	$ 13,595	$ 7,857	$ 4,493	$ 9,185	$ 7,147	$ 9,029
45-50%	$ 7,315	$ 11,990	$ 11,789	$ 6,359	$ 11,671	$ 10,713	$ 5,170
50-55%	$ 10,125	$ 13,127	$ 5,841	$ 6,575	$ 8,735	$ 8,386	$ 9,146
55-60%	$ 6,987	$ 10,363	$ 6,555	$ 8,082	$ 9,199	$ 8,698	$ 4,026
60-65%	$ 7,329	$ 9,856	$ 5,702	$ 3,712	$ 10,287	$ 7,733	$ 2,210
65-70%	$ 4,182	$ 11,035	$ 4,402	$ 4,743	$ 9,417	$ 4,662	$ 1,812
70-75%	$ 2,664	$ 4,782	$ 3,696	$ 5,625	$ 9,506	$ 4,374	$ 1,531
75-80%	$ 5,654	$ 10,001	$ 5,855	$ 9,589	$ 12,935	$ 5,787	$ 1,889
80-85%	$ 8,166	$ 15,094	$ 5,759	$ 7,688	$ 11,423	$ 6,720	$ 3,417
85-90%	$ 6,750	$ 13,184	$ 8,647	$ 20,189	$ 12,782	$ 7,770	$ 2,139
90-95%	$ 4,648	$ 16,324	$ 10,152	$ 13,350	$ 14,073	$ 10,863	$ 3,396
95-100%	$ 8,734	$ 13,113	$ 15,055	$ 10,884	$ 10,222	$ 5,518	$ 9,842
Unmapped/Unscored	$ 10,699	$ 19,887	$ 22,648	$ 22,326	$ 38,530	$ 28,465	$ 29,055
Total Investment (%)	$ 162,235	$ 245,260	$ 177,459	$ 161,099	$ 219,968	$ 169,031	$ 190,597

Line No.

1 **Table 10 Percent of Vegetation Management Investments**
2 **by EJ Gradations**

3

EJ Gradations	2021 Investment (%)	2022 Investment (%)	2023 Investment (%)	2024 Investment (%)	2025 Investment (%)	2026 Investment Forecast (%)	2027 Investment Forecast (%)
0-5%	1%	1%	1%	0%	0%	0%	1%
5-10%	6%	2%	5%	2%	2%	5%	9%
10-15%	7%	5%	8%	3%	1%	3%	14%
15-20%	4%	2%	5%	3%	3%	2%	6%
20-25%	5%	5%	3%	5%	5%	4%	7%
25-30%	10%	5%	5%	5%	3%	5%	9%
30-35%	7%	7%	6%	3%	4%	6%	7%
35-40%	5%	6%	5%	2%	6%	6%	4%
40-45%	5%	6%	4%	3%	4%	4%	5%
45-50%	5%	5%	7%	4%	5%	6%	3%
50-55%	6%	5%	3%	4%	4%	5%	5%
55-60%	4%	4%	4%	5%	4%	5%	2%
60-65%	5%	4%	3%	2%	5%	5%	1%
65-70%	3%	4%	2%	3%	4%	3%	1%
70-75%	2%	2%	2%	3%	4%	3%	1%
75-80%	3%	4%	3%	6%	6%	3%	1%
80-85%	5%	6%	3%	5%	5%	4%	2%
85-90%	4%	5%	5%	13%	6%	5%	1%
90-95%	3%	7%	6%	8%	6%	6%	2%
95-100%	5%	5%	8%	7%	5%	3%	5%
Unmapped/Unscored	7%	8%	13%	14%	18%	17%	15%
Total Investment (%)	100%	100%	100%	100%	100%	100%	100%

4 **Table 11 Conversion Investments by EJ Gradations**

EJ Gradations	2021 Investment ($000)	2022 Investment ($000)	2023 Investment ($000)	2024 Investment ($000)	2025 Investment ($000)	2026 Investment Forecast ($000)	2027 Investment Forecast ($000)
0-5%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5-10%	$ 127	$ 51	$ 399	$ 1,845	$ 1,267	$ 1,612	$ 1,343
10-15%	$ 464	$ 1,118	$ 439	$ 847	$ 1,836	$ 4,066	$ 6,114
15-20%	$ 2,359	$ 5,468	$ 1,748	$ 4,130	$ 794	$ 881	$ 372
20-25%	$ 2,423	$ 7,370	$ 3,787	$ 3,530	$ 6,647	$ 1,723	$ 3,987
25-30%	$ 523	$ 480	$ 2,094	$ 7,552	$ 515	$ 185	$ 796
30-35%	$ 3,753	$ 9,445	$ 3,464	$ 5,509	$ 5,380	$ 10,291	$ 13,711
35-40%	$ 143	$ 329	$ 319	$ 298	$ 354	$ 2,150	$ 2,665
40-45%	$ 16	$ 65	$ 235	$ 231	$ 1,624	$ 2,328	$ 4,328
45-50%	$ 505	$ 4,188	$ 1,656	$ 1,825	$ 9,126	$ 3,241	$ 7,696
50-55%	$ 380	$ 1,141	$ 887	$ 2,512	$ 6,503	$ 5,547	$ 8,238
55-60%	$ 793	$ 2,362	$ 6,227	$ 12,599	$ 6,027	$ 4,874	$ 4,164
60-65%	$ 340	$ 106	$ 497	$ 1,586	$ 3,738	$ 4,087	$ 5,248
65-70%	$ 595	$ 1,101	$ 8,909	$ 22,346	$ 15,929	$ 10,477	$ 8,235
70-75%	$ 1,001	$ 295	$ 833	$ 1,909	$ 1,674	$ 1,934	$ 1,695
75-80%	$ 3,149	$ 4,188	$ 11,090	$ 27,324	$ 15,461	$ 11,940	$ 11,765
80-85%	$ 816	$ 3,335	$ 11,149	$ 12,555	$ 22,541	$ 11,058	$ 5,254
85-90%	$ 2,147	$ 4,319	$ 11,646	$ 10,913	$ 28,275	$ 16,672	$ 11,339
90-95%	$ 4,732	$ 8,542	$ 18,081	$ 28,032	$ 21,618	$ 25,487	$ 17,807
95-100%	$ 32,162	$ 44,649	$ 67,524	$ 61,180	$ 52,377	$ 57,608	$ 38,182
Unmapped/Unscored	$ 2,665	$ 5,930	$ 11,126	$ 12,756	$ 36,701	$ 34,175	$ 33,812
Total Investment ($)	$ 59,092	$ 104,483	$ 162,109	$ 219,479	$ 238,387	$ 210,338	$ 186,750

Line No.

1 **Table 12 Percent of Conversion Investments by EJ Gradations**

EJ Gradations	2021 Investment (%)	2022 Investment (%)	2023 Investment (%)	2024 Investment (%)	2025 Investment (%)	2026 Investment Forecast (%)	2027 Investment Forecast (%)
0-5%	0%	0%	0%	0%	0%	0%	0%
5-10%	0%	0%	0%	1%	1%	1%	1%
10-15%	1%	1%	0%	0%	1%	2%	3%
15-20%	4%	5%	1%	2%	0%	0%	0%
20-25%	4%	7%	2%	2%	3%	1%	2%
25-30%	1%	0%	1%	3%	0%	0%	0%
30-35%	6%	9%	2%	3%	2%	5%	8%
35-40%	0%	0%	0%	0%	0%	1%	1%
40-45%	0%	0%	0%	0%	1%	1%	2%
45-50%	1%	4%	1%	1%	4%	2%	4%
50-55%	1%	1%	1%	1%	3%	3%	4%
55-60%	1%	2%	4%	6%	3%	2%	2%
60-65%	1%	0%	0%	1%	2%	2%	3%
65-70%	1%	1%	5%	10%	7%	3%	4%
70-75%	2%	0%	1%	1%	1%	1%	1%
75-80%	5%	4%	7%	12%	6%	6%	6%
80-85%	1%	3%	7%	6%	9%	5%	3%
85-90%	4%	4%	7%	5%	12%	8%	6%
90-95%	8%	8%	11%	13%	9%	12%	10%
95-100%	54%	43%	42%	28%	22%	28%	21%
Unmapped/Unscored	5%	6%	7%	6%	15%	17%	19%
Total Investment (%)	100%	100%	100%	100%	100%	100%	100%

2

3 **Q74. What do the Tables 5-12 show?**

4 A74. The tables demonstrate that a significant portion of the Company's distribution
5 investments are supporting vulnerable communities, and that the Company is
6 following through on its commitment to improving service reliability for these
7 communities. As highlighted in Table 5, 86%, 58%, and 23% of the investment in
8 the 4.8kV Hardening, 4.8kV Conversion, and Vegetation Management (Tree Trim)
9 programs for the period 2021 to 2025 was made in vulnerable communities.
10 Meaningful investment is expected to continue in vulnerable communities in future
11 years 2026-2027 as illustrated in Table 6 including 81%, 47%, and 14% of the total
12 investment in the Hardening, Conversion, and Vegetation Management programs
13 respectively. Both the Company's historical and future projected investment is
14 consistent with DTE Electric's commitment to improving reliability in vulnerable
15 communities.

Line No.

1 **Regulatory Requirements and Analysis of EJ**

2 **Q75. What did the Commission order in Case U-20147 regarding distribution**
3 **planning requirements related to EJ?**

4 A75. The Commission in 2025 ordered "Comparative reliability analysis of reliability
5 metrics against similarly situated non-EJ communities"[23].

6

7 **Q76. How does the current reliability performance of vulnerable community census**
8 **tracts compare with the rest of the DTE Electric system?**

9 A76. The census tracts with vulnerable customers are, on average, experiencing more
10 reliable electric service than the rest of the system.

11 As noted in Tables 13 through 16, vulnerable customers in the 80th percentile and
12 above generally see better reliability than the system average in SAIFI and SAIDI
13 in both All-Weather and Non-MED. This was also previously recognized by the
14 Commission in the Order in Case No. U-21534 where they stated "…on average,
15 vulnerable communities are seeing better reliability performance for both SAIDI
16 and SAIFI in both all-weather and when excluding MEDs.[24]" All-Weather and
17 Non-MEDs SAIFI is lower than the system average in every year and every
18 vulnerable community gradient. For Non-MED SAIDI, the vast majority of years
19 and vulnerable community gradients are better than the system average. All-
20 Weather shows more year-gradient combinations above the system average but
21 even for this metric, the majority of instances are better than the system average.

[23]Case No. U-20147 July 10, 2025 Order Exhibit A, pg. 6
[24] Case No. U-21534 January 23, 2025 Order, pg. 444.

Line No.

1 **Table 13 All Weather SAIFI Reliability Performance of Census**

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

Census Tract EJ % Group	Category	2021 SAIFI	2022 SAIFI	2023 SAIFI	2024 SAIFI	2025 SAIFI
0 to 5	AW	2.88	2.37	3.01	2.42	4.18
>5 to 10	AW	2.47	1.95	2.22	2.42	2.58
>10 to 15	AW	2.29	1.94	1.97	1.90	1.82
>15 to 20	AW	2.00	1.49	2.02	2.07	1.85
>20 to 25	AW	2.29	1.56	2.15	1.39	1.60
>25 to 30	AW	2.01	1.43	1.99	1.33	1.55
>30 to 35	AW	1.96	1.49	1.93	1.48	1.30
>35 to 40	AW	1.72	1.31	2.21	1.22	1.11
>40 to 45	AW	1.50	1.12	1.86	1.08	1.08
>45 to 50	AW	1.58	1.17	1.64	1.22	1.02
>50 to 55	AW	1.53	1.16	1.68	1.21	1.04
>55 to 60	AW	1.39	1.37	1.52	1.22	1.00
>60 to 65	AW	1.29	0.96	1.51	1.12	1.03
>65 to 70	AW	1.48	1.18	1.90	1.36	1.21
>70 to 75	AW	1.58	1.13	1.58	1.27	1.16
>75 to 80	AW	1.50	1.08	1.71	1.16	1.13
>80 to 85	AW	1.56	1.18	1.47	1.24	1.06
>85 to 90	AW	1.14	1.12	1.54	0.98	0.91
>90 to 95	AW	1.33	1.03	1.52	1.00	0.84
>95 to 100	AW	1.19	1.15	1.49	0.73	0.73
No EJ Score	AW	0.92	1.01	1.27	0.77	0.81
System Average	AW	1.58	1.25	1.72	1.25	1.16

Over performing system average

Under performing system average

System average

Line No.

1 **Table 14 Excluding MEDs SAIFI Reliability Performance of**

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

Census Tract EJ % Group	Category	2021 SAIFI	2022 SAIFI	2023 SAIFI	2024 SAIFI	2025 SAIFI
0 to 5	exMED	1.84	1.94	1.56	1.98	3.83
>5 to 10	exMED	1.35	1.54	1.27	1.86	2.33
>10 to 15	exMED	1.47	1.55	1.01	1.47	1.47
>15 to 20	exMED	1.15	1.25	1.17	1.62	1.65
>20 to 25	exMED	1.42	1.33	1.15	1.08	1.36
>25 to 30	exMED	1.16	1.17	1.13	1.00	1.34
>30 to 35	exMED	1.06	1.16	0.88	1.03	1.18
>35 to 40	exMED	0.99	1.00	1.10	0.83	1.01
>40 to 45	exMED	0.85	0.88	0.81	0.76	1.02
>45 to 50	exMED	0.94	0.98	0.75	0.86	0.94
>50 to 55	exMED	0.85	0.91	0.82	0.89	0.97
>55 to 60	exMED	0.84	1.10	0.77	0.91	0.91
>60 to 65	exMED	0.76	0.75	0.75	0.80	0.98
>65 to 70	exMED	0.84	0.98	0.93	1.03	1.16
>70 to 75	exMED	0.95	0.90	0.75	1.00	1.07
>75 to 80	exMED	0.93	0.85	0.87	0.94	1.08
>80 to 85	exMED	0.92	0.92	0.70	0.91	1.01
>85 to 90	exMED	0.68	0.78	0.71	0.80	0.85
>90 to 95	exMED	0.78	0.76	0.71	0.74	0.79
>95 to 100	exMED	0.64	0.77	0.78	0.59	0.70
No EJ Score	exMED	0.58	0.86	0.60	0.59	0.78
System Average	exMED	0.92	0.98	0.86	0.94	1.07

Over performing system average

Under performing system average

System average

Line No.

1 **Table 15 All Weather SAIDI Reliability Performance of Census**

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

Census Tract EJ % Group	Category	2021 SAIDI	2022 SAIDI	2023 SAIDI	2024 SAIDI	2025 SAIDI
0 to 5	AW	2656	1262	3278	937	620
>5 to 10	AW	1657	909	1604	867	540
>10 to 15	AW	930	916	1618	625	407
>15 to 20	AW	1096	576	1184	813	380
>20 to 25	AW	1291	527	1937	495	327
>25 to 30	AW	1174	611	1521	551	308
>30 to 35	AW	1211	692	1748	670	255
>35 to 40	AW	1027	666	1889	643	211
>40 to 45	AW	940	433	1834	433	167
>45 to 50	AW	999	426	1584	537	162
>50 to 55	AW	946	458	1482	474	167
>55 to 60	AW	775	531	1268	490	155
>60 to 65	AW	764	473	1363	498	142
>65 to 70	AW	816	416	1745	464	148
>70 to 75	AW	844	472	1515	475	153
>75 to 80	AW	820	389	1509	376	143
>80 to 85	AW	978	556	1419	539	158
>85 to 90	AW	705	735	1699	342	122
>90 to 95	AW	840	749	1675	362	132
>95 to 100	AW	804	923	1133	221	141
No EJ Score	AW	355	300	778	224	108
System Average	AW	927	584	1542	483	192

Over performing system average

Under performing system average

System average

Line No.

1 **Table 16 Excluding MEDs SAIDI Reliability Performance of**

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

Census Tract EJ % Group	Category	2021 SAIDI	2022 SAIDI	2023 SAIDI	2024 SAIDI	2025 SAIDI
0 to 5	exMED	398	487	373	501	544
>5 to 10	exMED	213	296	320	325	365
>10 to 15	exMED	209	274	236	249	245
>15 to 20	exMED	150	238	212	274	280
>20 to 25	exMED	248	182	239	199	221
>25 to 30	exMED	177	188	217	177	211
>30 to 35	exMED	136	152	158	183	180
>35 to 40	exMED	138	146	173	171	165
>40 to 45	exMED	111	103	152	106	138
>45 to 50	exMED	149	131	135	145	130
>50 to 55	exMED	124	128	136	137	139
>55 to 60	exMED	112	150	155	160	128
>60 to 65	exMED	114	138	139	122	122
>65 to 70	exMED	131	120	138	169	129
>70 to 75	exMED	122	115	119	147	120
>75 to 80	exMED	128	106	145	146	130
>80 to 85	exMED	147	156	149	144	142
>85 to 90	exMED	111	123	130	146	101
>90 to 95	exMED	112	115	129	127	116
>95 to 100	exMED	94	129	142	101	111
No EJ Score	exMED	68	98	80	88	97
System Average	exMED	136	146	157	159	151

Over performing system average

Under performing system average

System average

Line No.

1 **Q77. Is the population of customers spread equally among the EJ gradients?**

2 A77. No. The distribution of residential customers in each gradation is highlighted in
3 Table 17 below. Approximately 27% of DTE Electric residential customers fall into
4 the 80% to 100% vulnerable gradations.

5

6 **Table 17 Residential Customers by EJ Gradations**

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

7

8 **Q78. What were the Commission's findings in Case No. U-21534 (2024) related to**
9 **EJ in the Company's distribution planning?**

10 A78. In Case No. U-21534 the Commission found that the Company's use of the
11 MiEJScreen tool to be a reasonable starting point for equity-related analyses and
12 acknowledged the Company's mapping of reliability investments to vulnerable
13 communities, with significant investments in 4.8kV Hardening and 4.8kV

Line No.

1 Conversions.[25] They also issued a recommendation to evaluate changing
2 demographics over time for detailed EJ community reliability regression analysis.[26]
3
4 **Q79. What were the Commission's findings in the subsequent Case No. U-21860**
5 **(2025) related to EJ in the Company's distribution planning?**
6 A79. Expanding on the EJ analysis that DTE Electric had already performed, the
7 Commission directed the Company to 1) run a regression analysis in all of the future
8 rate cases and DSPs, 2) conduct an analysis comparing service reliability in EJ
9 census tracts to non-EJ census tracts with similar population densities and other
10 characteristics, 3) include distributions across EJ gradations in the company's
11 reliability reporting and 4) pair the MiEJScreen tool with reliability and energy-
12 burden indicators so that investments increase reliability without worsening
13 affordability.[27] I discuss the Company's response to these directives below.
14
15 **Q80. Did the Company complete the directive for the regression analysis?**
16 A80. Yes. The Company initiated an EJ regression study in 2024 in collaboration with
17 outside parties, most notably the Commission Staff and Clean Energy
18 Organizations (CEO). The objective of this effort was to evaluate the hypothesis
19 that a statistical correlation exists between the EJ score and reliability performance,
20 as measured by SAIFI and SAIDI, after adjusting for circuit-level characteristics
21 known to influence reliability outcomes. To prepare the dataset, DTE Electric
22 gathered and validated reliability metrics and circuit characteristics, reviewing
23 more than 10,000 data points to ensure completeness and accuracy. The Company

[25] Case No. U-21534, January 23, 2025 Order pg. 443-444
[26] Case No. U-21534, January 23, 2025 Order pg. 124
[27] Case No. U-21860, February 19, 2026 Order pg. 423

Line No.

ran a simple univariate analysis comparing vulnerable to non-vulnerable customers across four metrics: SAIFI and SAIDI under both all-weather and exMED conditions. Next, a set of detailed models applied multiple linear regression, testing the EJ score as both a continuous and categorical variable across the same four reliability metrics, however the linear regression approach did not meet several key assumptions necessary for valid inference. To address these limitations, the Company next developed nonlinear regression models using the log-transformed reliability metrics, however this analysis also had notable statistical concerns, particularly its inability to satisfy the independence assumption required for valid inference due to unaccounted-for factors related to circuit configuration. The team then used a more flexible framework, specifically a linear mixed-effects modeling approach. Eight models were estimated using log-transformed SAIFI and SAIDI for both all-weather and exMED, again testing the EJ score as both a continuous and categorical variable. While linear mixed-effects modeling approach was an improvement over the nonlinear modeling, it still relied on at least one assumption that did not appear to be fully met. Finally, the Company used a Generalized Estimating Equations (GEE) model where all the assumptions were satisfied and provided similar results to mixed model and log-transformed models.

DTE Electric will continue evaluating the data and refining its statistical methods to deepen understanding of system and the reliability experienced by vulnerable customers. See DSP Appendix 8.7 (Environmental Justice Regression Analysis), for the complete regression report. A summary of this work is also contained in DSP Section 4.7.

Line No.

1 **Q81. Did the Company complete the ordered changing demographics analysis?**

2 A81. Yes. The Company met with various stakeholders to align on the analysis
3 methodology to assess whether material demographic changes have occurred since
4 the MiEJScreen Tool was released. The analysis, which used the American
5 Community Survey available from the US Census Bureau, identified that the shifts
6 in the demographics of four factors since the 2020 census were very small.
7 Additional discussion of this analysis and its application is provided in the 2026
8 DSP. The technical paper detailing the changing demographics analysis is included
9 in the appendix of the 2026 DSP, Exhibit A-23, Schedule M1.

10

11 **Q82. Please describe the Company's analysis comparing service reliability in EJ**
12 **census tracts to non-EJ census tracts with similar population densities and**
13 **other characteristics.**

14 A82. The analysis comparing service reliability in EJ and non-EJ census tracts of similar
15 population density is provided in Exhibit A-23, Schedule M18 tab "Summary",
16 rows 19-36. Density was broken down into system wide quartiles for comparison
17 using 2024 reliability data. Vulnerable communities show better reliability
18 performance in every density quartile than communities that score less than 80% in
19 the MIEJScreen Tool.

20

21 **Q83. Where is the 2024 distribution reliability data for the EJ communities grouped**
22 **by EJ gradients found in Exhibit A-23, Schedule M?**

23 A83. The reliability performance across EJ population distributions in 2024, for SAIDI
24 and SAIFI metrics excluding MEDs and All-Weather compared to the systemwide
25 levels, are shown in Exhibit A-23, Schedule M18, tab "Summary", rows 1-12.

Line No.

1 **Q84. Where in Exhibit A-23, Schedule M18 is the analysis that pairs the**
2 **MiEJScreen tool scores with reliability and energy-burden indicators?**
3 A84. Yes. The paired analysis is shown in Exhibit A-23, Schedule M18, tab "2020
4 Census", columns I and N. Energy-burden is assumed to be estimated yearly
5 electricity charge divided by median household income. Energy-burden
6 information was taken from the 2024 American Community Survey available from
7 the US Census Bureau.[28]
8
9 **Q85. Were there additional directives in Case U-21860 regarding EJ?**
10 A85. Yes. As noted in the GPM section, the Order directed the Company to "better
11 account for the number of residential customers on a given circuit rather than just
12 the proportion of customers living in an EJ community, if possible, when
13 prioritizing EJ in its GPM model, incorporate EJ into its Reliability Model, and
14 build EJ considerations into the CE and SRIP programs to further target
15 disadvantaged communities."[29]
16
17 **Q86. Did the Company review potential changes to the EJ multiplier that**
18 **incorporated the number of residential customers in the GPM model?**
19 A86. Yes. The Company considered two alternative approaches to incorporate residential
20 customer count differently as part the EJ multiplier, within the GPM, and concluded
21 that the current method is most appropriate. These changes are discussed in detail
22 in Q&A above.

[28] American Community Survey, American Community Survey (ACS), accessed February 13th, 2026.
[29] Case No. U-21860, February 19, 2026 Order pg. 423

Line No.

Q87. Has the Company incorporated EJ into the Reliability Model Outputs?

A87. Yes. The Company has incorporated EJ as a field in the Reliability Model Output Exhibit A-23, M7.

Q88. Please discuss how the Company plans to incorporate EJ into the CE and SRIP programs.

A88. The Company will work with staff and stakeholders in 2026 to determine appropriate prioritization methods, with this prioritization planned to begin in 2027.

Q89. Can you provide an overview of the findings of the Audit regarding the Company's efforts to incorporate EJ into its planning.

A89. The Audit noted that the Company has made strides in integrating EJ into distribution planning and intends to continue enhancing these efforts over time. The Audit also noted that "the Company's ongoing plans to significantly invest in the hardening and replacement of aging 4.8kV infrastructure, while not targeted to Detroit's most vulnerable communities, will benefit electric reliability of those communities."[30]

Q90. What are the Company's future plans to address EJ in the context of distribution planning and operations?

A90. DTE Electric plans to continue to analyze reliability and investment data using the MiEJScreen tool, including the consideration of any updates based on the state's release of the tool's latest version. The Company intends to continue to include EJ considerations in investment decisions, as well as continue to address poor

[30] Case No. U-21305; Part Two; Ch. 1; pg. 23.

Line No.

1 performing circuits in vulnerable communities. Additionally, DTE Electric is
2 working with MPSC Staff and Stakeholders on a collaborative regression analysis
3 considering the MiEJScreen Tool Score and reliability metrics for inclusion in the
4 Company's next DGP as directed by the Commission.[31]
5
6 **Q91. Does this complete your direct testimony?**
7 A91. Yes, it does.

[31] On December 1, 2023, the Commission issued an order in Case No. U-21297 pg. 352, requesting DTE Electric to work with Commission Staff and stakeholders to develop regression analysis of customer demographics and reliability for vulnerable communities.

Case No.: U-22046
Exhibit: Revised A-13
Schedule: Revised C5.6
Witness: A. J. Kryscynski
C. J. Hartley 1/
W.T. Hutchinson 2/
J. E. Robinson 6/

Michigan Public Service Commission
DTE Electric Company
Projected Operation and Maintenance Expenses
Distribution Expenses
($000)

	(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
								Projected Adjustments					
Line No.	Description		Account	1/1/25 - 12/31/25 Historical Test Period	Historical Adjustments 3/	Normalization Adjustments 4/	Adjusted Historical Test Period	1/1/26 - 12/31/26 Inflation Adj 5/	1/1/27 - 12/31/27 Inflation Adj 5/	1/1/28 - 2/29/28 Inflation Adj 5/	Other Adjustments 6/	Total Projected Adjustments	Projected Test Period
							sum (c) thru (e)					sum (g) thru (j)	(f) + (k)
1	**Distribution Expenses**												
2	Miscellaneous Transmission Expenses		566	-	-	-	-	-	-	-	-	-	-
3	Operation Supervision and Engineering		580	63,930	-	-	63,930	1,854	1,974	327	11,033	15,188	79,117
4	Load Dispatching		581	1,355	-	-	1,355	39	42	7	-	88	1,443
5	Station Expenses		582	4,734	-	-	4,734	137	146	24	-	308	5,041
6	Overhead Line Expenses		583	5,524	-	-	5,524	160	171	28	-	359	5,883
7	Underground Line Expenses		584	834	-	-	834	24	26	4	-	54	888
8	Street Lighting and Signal System Exp	1/	585	-	-	-	-	-	-	-	-	-	-
9	Meter Expenses		586	9,643	-	-	9,643	280	298	49	-	627	10,269
10	Customer Installations Expenses		587	417	-	-	417	12	13	2	-	27	444
11	Miscellaneous Expenses		588	28,788	-	-	28,788	835	889	147	7,868	9,739	38,527
12	Amortization of Deferred ADMS Costs		588	1,174		-	1,174				-	-	1,174
13	Rents		589	2,460	-	-	2,460	-	-	-	-	-	2,460
14	Total Operation Expense			118,857	-	-	118,857	3,341	3,557	590	18,901	26,390	145,247
15	**Maintenance**												
16	Maintenance Supervision and Engineering		590	2,104	-	-	2,104	61	65	11	-	137	2,241
17	Maintenance of Structures		591	2,727	-	-	2,727	79	84	14	-	177	2,904
18	Maintenance of Station Equipment		592	15,913	-	-	15,913	461	491	82	1,733	2,767	18,680
19	Maintenance of Overhead Lines- Vegetation Management	2/	593	108,101	-	-	108,101	-	-	-	122,065	122,065	230,167
20	Maintenance of Overhead Lines-Other		593	46,227	-	47,267	93,494	2,711	2,886	479	10,019	16,095	109,589
21	Maintenance of Underground Lines		594	10,704	-	-	10,704	310	330	55	9,560	10,256	20,960
22	Maintenance of Line Transformers		595	-	-	-	-	-	-	-	-	-	-
23	Maintenance of Street Lighting and Signal Systems	1/	596	4,142	-	-	4,142	120 -	128 -	21 -	262	531	4,674
24	Maintenance of Meters		597	-	-	-	-	-	-	-	-	-	-
25	Maintenance of Misc Distribution Plant		598	-	-	-	-	-	-	-	-	-	-
26	Total Maintenance Expense			189,920	-	47,267	237,187	3,743	3,985	661	143,639	152,028	389,215
27	Total Distribution Expenses			308,777	-	47,267	356,044	7,085	7,542	1,252	162,540	178,418	534,462

Michigan Public Service Commission
DTE Electric Company
Projected Operation and Maintenance Expenses
Distribution Expenses
($000)

Other Sponsoring Witnesses

1/ Street Lighting and Signal Systems (accounts 585 and 596) are sponsored by Witness Hartley
2/ Vegetation Management Expenses (account 593) are sponsored by Witness Hutchinson (Exh. A-13 C5.6.1)

Historical Adjustments	Account	Amount
3/ No historical adjustments were required for the historical test year		
4/ Normalization Adjustments:		
Emergent Expense (Exh. A-13 C5.6 p.3, Line 18, col. (j)	593	47,267
Total Normalization Adjustments		47,267

Projection Adjustments

5/ Inflation Adjustment:	1/1/26 - 12/31/26	1/1/27 - 12/31/27	1/1/28 - 2/29/28
Annual Rate	2.90%	3.00%	2.90%
No. of Months in Period	12	12	2
Pro-rated Inflation Rate	2.90%	3.00%	0.48%

(sponsored by Witness T. Uzenski on Exh. A-13, Sch.C5.15)

6/ Other Projected Adjustments:	Account	Amount
Community Lighting Normalized Outage Repair Volume	596	262
Vegetation Management	593	122,065
Damage Prevention Increase sponsored by Witness Hill Exh. A-13, Sch. C5.6, p. 4, Line 7, Col. (i)	580	1,038
Preventative Maintenance sponsored by Witness Robinson	580, 590, 591, 592, 593, 594	8,169
7/ PTMM - Pole Top Inspections sponsored by Witness Robinson	593	2,779
7/ PTMM - Pole Inspections sponsored by Witness Robinson	593	1,391
7/ PTMM - Infrared Thermography sponsored by Witness Robinson	593	1,900
Corrective Maintenance sponsored by Witness Robinson	580, 593, 594	9,081
System Cable Testing Program sponsored by Witness Robinson	594	3,167
Workforce Augmentation	580, 592, 593, 594	6,890
ADMS: Network Management System sponsored by Witness Rademacher	588	500
Cloud Services	588	956
NERC Compliance	588	700
Next-Gen AMI sponsored by Witness Rademacher	588	3,642
Total Projection Adjustments		162,540

7/ PTMM Pole Top and Pole Inspections adjustment will not align to the BCA model results due to timing differences

Michigan Public Service Commission
DTE Electric Company
Projected Operation and Maintenance Expenses
Distribution Expenses - Emergent Expenses
($000)

Case No.: U-22046
Exhibit: Revised A-13
Schedule: Revised C5.6
Witness: B. L. Hill
Page: 3 of 4

	(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
Line No.	**Description**		**Actual 2021**	**Actual 2022**	**Actual 2023**	**Actual 2024**	**Actual 2025**	**5 Yr Avg**	**3/1/27 - 2/29/28 Projected Test Period**	**1/1/25 - 12/31/25 Historical Test Period**	**Emergent Adjustment**
											(h) - (i)
1	**Storm**										
2	Actual O&M Reported		73,429	60,850	183,671	59,672	20,929	79,710			
3	Inflation Adjustment		-	-	-	-	-	-			
4	Inflation Adjusted Historical O&M		73,429	60,850	183,671	59,672	20,929	79,710	79,710	20,929	58,782
5	Inflation 1/1/26 -12/31/26	2.90%							2,312	607	1,705
6	Inflation 1/1/27 -12/31/27	3.00%							2,461	646	1,815
7	Inflation 1/1/28 -2/29/28	0.48%							408	107	301
8	**Projected Storm**								84,891	22,289	62,602
9	**Non-Storm**										
10	Actual O&M Reported		47,657	59,116	51,165	49,199	66,178	54,663			
11	Inflation Adjustment		-	-	-	-	-	-			
12	Inflation Adjusted Historical O&M		47,657	59,116	51,165	49,199	66,178	54,663	54,663	66,178	(11,515)
13	Inflation 1/1/26 -12/31/26	2.90%							1,585	1,919	(334)
14	Inflation 1/1/27 -12/31/27	3.00%							1,687	2,043	(355)
15	Inflation 1/1/28 -2/29/28	0.48%							280	339	(59)
16	**Projected Non-Storm**								58,216	70,479	(12,263)
17	**Total Emergent Expense**										
18	**Total Emergent Normalization Adjustment (Line 4 + Line 12)**								**134,373**	**87,106**	**47,267** 1/
19	Inflation 1/1/26 -12/31/26	2.90%							3,897	2,526	1,371
20	Inflation 1/1/27 -12/31/27	3.00%							4,148	2,689	1,459
21	Inflation 1/1/28 -2/29/28	0.48%							688	446	242
22	**Total Projected Emergent Expense (Line 8 + Line 16)**								**143,107**	**92,768**	**50,339**

1/ Historical normalization adjustment carried to Account 593 (see Exhibit A-13 C5.6 page 1 line 20).

Michigan Public Service Commission
DTE Electric Company
Projected Operation and Maintenance Expenses
Distribution Expenses - Damage Prevention
($000)

Case No.: U-22046
Exhibit: Revised A-13
Schedule: Revised C5.6
Witness: B. L. Hill
Page: 4 of 4

	(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
							Projected Adjustments					
Line No.	Description		Account	1/1/25 - 12/31/25 Historical Test Period	Normalization Adjustments 1/	Adjusted Historical Test Period	1/1/26 - 12/31/26 Inflation Adj 2/	1/1/27 - 12/31/27 Inflation Adj 2/	1/1/28 - 2/29/28 Inflation Adj 2/	Other Adjustments 3/	Total Projected Adjustments	Projected Test Period
						sum (c) thru (d)					sum (f) thru (i)	(e) + (j)
1	**Distribution Damage Prevention**											
2	Miss Dig Fees		580	539	-	539	16	17	3	-	35	574
3	Contractor Staking	4/	580	8,964	-	8,964	-	-	-	1,038	1,038	10,002
4	Internal Staking		580	-	-	-	-	-	-	-	-	-
5	Administration		580	-	-	-	-	-	-	-	-	-
6				-	-	-	-	-	-	-	-	-
7	Total Damage Prevention Expense			9,503	-	9,503	16	17	3	1,038	1,073	10,576

1/ No historical adjustments were required for the historical test year

Projection Adjustments

2/ Inflation Adjustment:	1/1/26 - 12/31/26	1/1/27 - 12/31/27	1/1/28 - 2/29/28
Annual Rate	2.90%	3.00%	2.90%
No. of Months in Period	12	12	2
Pro-rated Inflation Rate	2.90%	3.00%	0.48%

(sponsored by Witness T. Uzenski on Exh. A-13, Sch.C5.15)

3/ Other Projected Adjustments:	Account	Amount
Damage Prevention Increase sponsored by Witness Hill Exh. A-13, Sch. C5.6, p. 4, Line 7, Col. (i)	580	1,038

4/ Removed inflation on Contractor Staking per Case No. U-21860 Order dated 01/19/2026, page 325

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-22046
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS

AND

REVISED DIRECT TESTIMONY

OF

JENNIFER E. NELSON

DTE ELECTRIC COMPANY
QUALIFICATIONS AND REVISED DIRECT TESTIMONY OF JENNIFER E. NELSON

Line No.

Q1. What is your name, business address, and occupation?

A1. My name is Jennifer E. Nelson. My business address is 293 Boston Post Road West, Suite 500, Marlborough, Massachusetts, 01752. I am a Vice President at Concentric Energy Advisors, Inc. ("Concentric"). Concentric is a management consulting and economic advisory firm that specializes in the North American energy and water industries. Based in Marlborough, Massachusetts; Washington, D.C.; and Calgary, Alberta, Concentric specializes in regulatory and litigation support, financial advisory services, energy market strategies, market assessments, energy commodity contracting and procurement, economic feasibility studies, and capital market analyses.

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of DTE Electric Company ("DTE Electric" or the "Company").

Q3. What is your educational and professional background?

A3. I have a Bachelor of Science degree in Business Economics from Bentley University and a Master of Science degree in Resource and Applied Economics from the University of Alaska. I am a member of the Society of Utility and Regulatory Financial Analysts and earned the Certified Rate of Return Analyst designation based on my experience and successful completion of an examination.

Q4. What is your work experience?

Line No.

1 A4. I have more than fifteen years of experience in the energy industry, having served
2 as a consultant and energy/regulatory economist for state government agencies.
3 Since 2013, I have provided consulting services to clients on a range of financial
4 and regulatory issues including cost of capital, ratemaking policy, and regulatory
5 strategy. Prior to consulting, I was a staff economist at the Massachusetts
6 Department of Public Utilities and a petroleum economist for the State of Alaska.
7 I completed utility regulatory training offered by New Mexico State University's
8 Center for Public Utilities. A summary of my professional and educational
9 background, including a list of my testimony filed before regulatory commissions,
10 is included as Exhibit A-14 Schedule D5.1.
11
12 **Q5. Have you previously submitted testimony before the Michigan Public Service**
13 **Commission ("MPSC" or "Commission")?**
14 A5. Yes, I filed testimony regarding the cost of capital on behalf of DTE Electric in
15 Case No. U-21860 and DTE Gas Company in Case No. U-21973. Additionally, I
16 have filed testimony before more than 20 state regulatory commissions as detailed
17 in Exhibit A-14 Schedule D5.1. During my time as a consultant, I have supported
18 the development of expert witness testimony and analyses regarding the cost of
19 capital (*i.e.*, Return on Equity ("ROE") and capital structure) in more than 100
20 proceedings filed before numerous U.S. state regulatory commissions and the
21 Federal Energy Regulatory Commission.

Line No.

1 **I. Purpose of Testimony**

2 **Q6. What is the purpose of your testimony?**

3 A6. The purpose of my direct testimony is to present evidence and provide the
4 Commission with a recommendation regarding DTE Electric's ROE and to
5 evaluate the reasonableness of its requested capital structure.

6

7 **Q7. Are you sponsoring any exhibits in this proceeding?**

8 A7. Yes. I am sponsoring the following exhibits:

Exhibit	Schedule	Description
Exhibit A-14	D5	Projected Cost of Common Shareholders' Equity
Exhibit A-14	D5.1	Résumé and Testimony Listing of Jennifer E. Nelson
Exhibit A-14	D5.2	Constant Growth DCF Results
Exhibit A-14	D5.3	Quarterly Growth DCF Results
Exhibit A-14	D5.4	Forward Market Return Calculations
Exhibit A-14	D5.5	CAPM and Empirical CAPM Results
Exhibit A-14	D5.6	Bond Yield Plus Risk Premium Analysis
Exhibit A-14	D5.7 Revised	Regulatory Risk Analysis
Exhibit A-14	D5.8	Proxy Group Authorized Equity Ratio

19

20 **Q8. Were these exhibits prepared by you or under your direction?**

21 A8. Yes, they were.

22

23 **II. Summary and Overview of Testimony**

24 **Q9. Please summarize your conclusions regarding the appropriate cost of equity**
25 **and capital structure in this proceeding.**

Line No.

1 A9. To develop my ROE recommendation, I rely on the results of three widely used
2 market-based financial models applied to a proxy group of companies comparable
3 in risk to DTE Electric: (1) the constant growth and quarterly growth forms of the
4 Discounted Cash Flow ("DCF") model, (2) the traditional and empirical forms of
5 the Capital Asset Pricing Model ("CAPM"), and (3) the Bond Yield Plus Risk
6 Premium analysis ("Risk Premium"). As shown in Table 1 below, these approaches
7 indicate a cost of equity in the range of 9.95 percent to 11.80 percent. My model
8 results, together with an assessment of DTE Electric's business and financial risk
9 compared to the proxy companies, fully support an ROE of 10.85 percent, which is
10 the approximate midpoint of the range. However, the Company has elected to
11 request an ROE of 10.25 percent in consideration of gradualism in adjusting key
12 drivers of rates. I support the Company's 10.25 percent ROE recommendation as
13 a reasonable and conservative estimate of DTE Electric's cost of equity.

Line No.

1 **Table 1 Summary of Results[1]**

Constant Growth DCF	Low	Mean	High
30-Day Average	9.64%	10.67%	11.57%
90-Day Average	9.59%	10.63%	11.54%
180-Day Average	9.68%	10.70%	11.66%
Quarterly Growth DCF	**Low**	**Mean**	**High**
30-Day Average	9.84%	10.88%	11.83%
90-Day Average	9.78%	10.84%	11.79%
180-Day Average	9.86%	10.95%	11.92%
CAPM		**Current 30-Year Treasury Yield (4.83%)**	**Projected 30-Year Treasury Yield (4.68%)**
Forward Market Return, 5-Yr Average Betas		12.62%	12.57%
Forward Market Return, 10-Yr Bloomberg Betas		13.49%	13.46%
Historical Market Return, 5-Yr Average Betas		9.82%	9.77%
Historical Market Return, 10-Yr Bloomberg Betas		10.38%	10.34%
Empirical CAPM		**Current 30-Year Treasury Yield (4.83%)**	**Projected 30-Year Treasury Yield (4.68%)**
Forward Market Return, 5-Yr Average Betas		13.56%	13.52%
Forward Market Return, 10-Yr Bloomberg Betas		14.22%	14.19%
Historical Market Return, 5-Yr Average Betas		10.42%	10.39%
Historical Market Return, 10-Yr Bloomberg Betas		10.84%	10.81%
Bond Yield Plus Risk Premium			
Current 30-Year Treasury Yield (4.83%)		10.36%	
Projected 30-Year Treasury Yield (4.68%)		10.28%	

2

3 As to the Company's capital structure, the requested permanent capital structure
4 consisting of 51.50 percent common equity and 48.50 percent long-term debt
5 reflects its projected capital structure and is more leveraged (*i.e.*, contains more

1 Schedules D5.2 to D5.6. DCF and CAPM model results are the average of the mean and median proxy group results. Data as of January 30, 2026.

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1 debt) than its electric utility peers on average. Accordingly, the Company's
2 requested capital structure is reasonable and should be approved.
3
4 **Q10. How do you determine your recommendation from the results summarized**
5 **above?**
6 A10. The cost of equity is an opportunity cost that cannot be precisely quantified.
7 Therefore, it must be estimated using various financial models. Each of the ROE
8 estimation models is subject to limiting assumptions and each provides a different
9 perspective on investors' return requirements under varying market conditions.
10 The use of multiple financial models, therefore, enables a robust and
11 comprehensive assessment of the cost of equity instead of relying on one specific
12 estimation model.
13
14 In addition to the analytical results summarized above, my recommendation
15 considers: (1) the Company's significant capital investment needs; (2) the regulatory
16 environment in which the Company operates; (3) DTE Electric's financial risk
17 reflected in its capital structure; and (4) the current capital market environment.
18 Although those factors are relevant to investors, their effect on the Company's cost
19 of equity cannot be directly quantified. While I do not make any explicit
20 adjustments to my ROE estimates for DTE Electric's business risks, I consider them
21 when determining my ROE recommendation.
22
23 Lastly, my recommendation reflects the current capital market and macroeconomic
24 environment in which utilities such as DTE Electric operate. Although these factors
25 are relevant to investors, their effect on the Company's cost of equity cannot be

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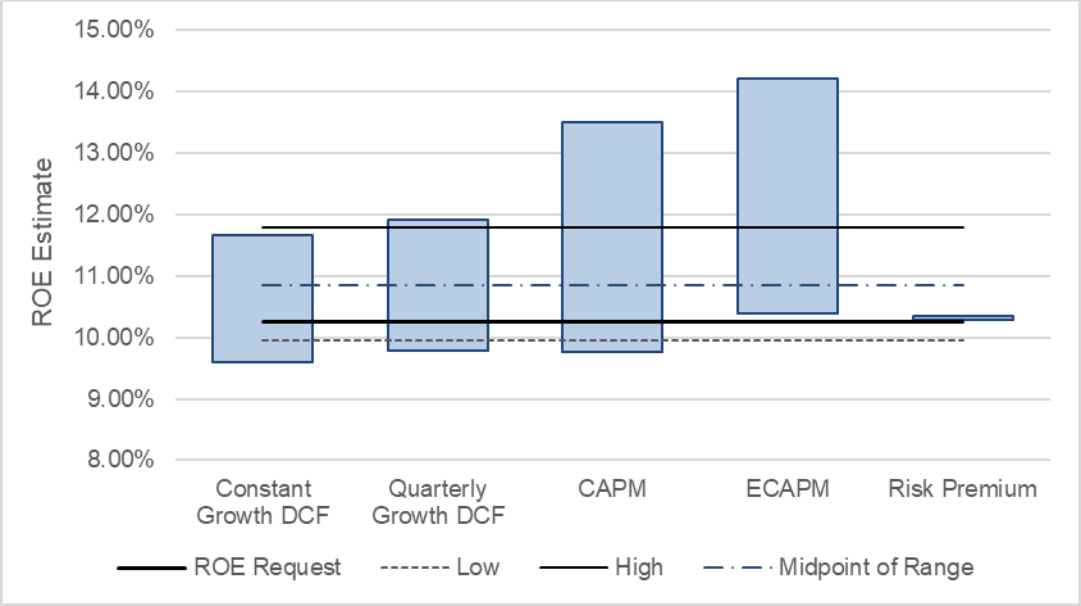
directly quantified and I have not made an explicit adjustment to my ROE recommendation to reflect these factors.

The low end of my range, 9.95 percent, is approximately equal to the average of the low DCF results, low CAPM results using the historical average market return, and Risk Premium results. The high end of my recommended range, 11.80 percent, is near the average of the CAPM and ECAPM results and high DCF results. As Figure 1 shows, an ROE of 10.85 percent is near the midpoint of the range of ROE model results, while the Company's requested 10.25 percent ROE is near the low end of the range of ROE model results and is a conservative estimate of DTE Electric's cost of equity.

Figure 1. Range of ROE Estimate Model Results and Recommendation



Q11. What is the trend in long-term interest rates and authorized ROEs for vertically integrated electric utilities?

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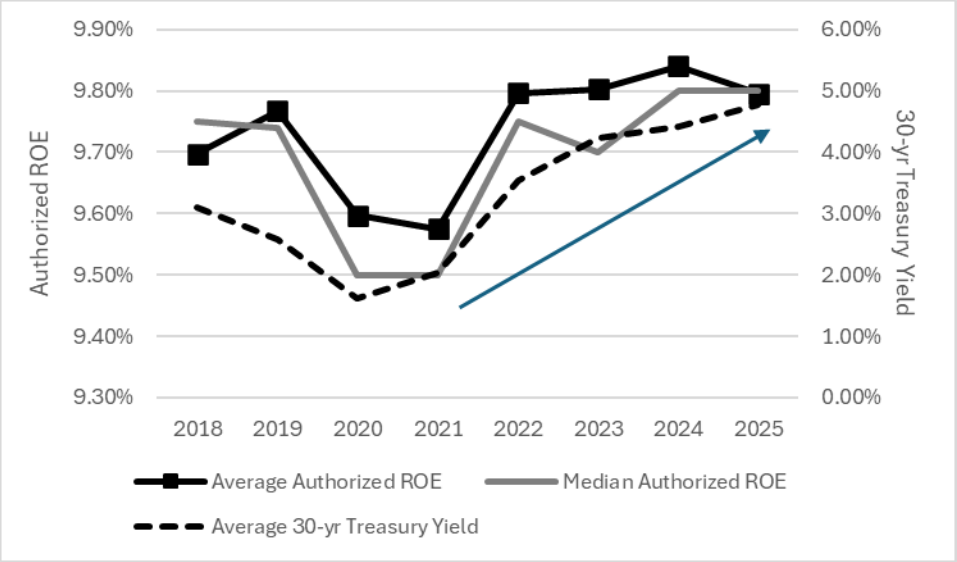
A11. Regulatory commissions have acknowledged the higher capital cost environment by authorizing higher ROEs. As shown in Figure 2, as the 30-year Treasury bond yield increased from the lows experienced in 2020 and 2021, authorized ROEs for vertically integrated electric utilities have increased. I note, however, that annual average and median authorized ROEs obscure the case specific nuances inherent in each proceeding and thus should not be viewed in a vacuum. Nevertheless, the trend in authorized ROEs has been increasing in recent years.

Figure 2. Average and Median Authorized ROEs for Vertically Integrated Electric Utilities and 30-Year Treasury Bond Yields (2018-2025)[2]



Q12. How is the remainder of your direct testimony organized?

A12. The remainder of my Direct Testimony is organized as follows:

2 Source: Regulatory Research Associates. Excludes limited issue rate rider proceedings and proceedings in which the ROE is set formulaically based on annual changes in the Treasury bond yield.

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- Section III – Summarizes the issues and regulatory guidelines relevant to the cost of capital estimation in regulatory proceedings, explains my selection of the proxy group used to develop my analytical results, and describes the analyses on which my ROE determination is based;
- Section IV – Discusses the effect of the Company's business risks on its cost of equity;
- Section V – Provides an assessment of the Company's proposed capital structure;
- Section VI – Reviews the current capital market conditions and the implication on the cost of equity; and
- Section VII – Summarizes my conclusions and recommendations.

III. Cost of Equity Estimation

Regulatory Guidelines and Principles

Q13. Before addressing the specific aspects of this proceeding, please explain the connection between the cost of capital and a utility's cost of service.

A13. Under the cost-of-service ratemaking paradigm, the development of utility rates begins with determining the utility's total cost to serve customers. This is known as the revenue requirement, since the utility's revenue must be sufficient to recover its cost to serve customers. The revenue requirement consists of four components: (1) operating and maintenance ("O&M") expenses, (2) taxes, (3) the return *of* capital through depreciation expense, and (4) the return *on* capital through the regulated return on rate base. The return on rate base is calculated as the weighted average cost of capital multiplied by the rate base. The return on capital must be sufficient to allow the utility to repay its debt obligations and compensate equity

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1 investors for the use of their financial capital. From that important perspective, the
2 return on capital reflects a cost to the utility just like any other component of the
3 revenue requirement.
4
5 **Q14. Please explain the cost of capital conceptually.**
6 A14. The cost of capital (*i.e.*, the costs of both debt and equity) is the return that investors
7 require to commit capital to a firm. Investors will provide funds to a firm only if
8 the return they *expect* is equal to, or greater than, the return they *require* to accept
9 the risk of investing capital in the firm. Simply, the cost of capital is the expected
10 rate of return prevailing in the capital markets on alternative investments of similar
11 risk.[3] Conceptually, the cost of capital is: (1) forward looking; (2) an opportunity
12 cost; (3) determined in the capital markets, and (4) dependent on, and proportional
13 to, the risk of the investment.[4]
14
15 Because the cost of equity is expectational and premised on the principle of
16 opportunity costs, it is not directly observable. Instead, it must be estimated using
17 market data applied to various financial models that reflect simplified
18 representations of investor behavior and expectations. Further, equity investors
19 have a claim on cash flows only *after* debt holders are paid; the uncertainty (or risk)
20 associated with those residual cash flows determines the cost of equity. Because
21 equity investors bear the residual risk, they take greater risks and require higher
22 returns than debt holders. In the end, the estimated cost of equity should reflect the

---

3 Lawrence A. Kolbe, James A. Read, Jr., and George R. Hall, The Cost of Capital – Estimating the Rate of Return for Public Utilities, The MIT Press, Cambridge, MA, at 13 (1985).

4 *Ibid*.

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1 return that investors require considering the subject company's risk profile and the
2 returns available on comparable investments.
3
4 **Q15. How is the cost of equity estimated in regulatory proceedings?**
5 A15. Regulated utilities primarily use long-term capital (*i.e.*, common stock, preferred
6 stock, and long-term debt) to finance their permanent rate base. The allowed rate
7 of return for a regulated utility is calculated as its weighted average cost of capital,
8 in which the costs of the individual sources of capital are weighted by their
9 respective book values. The ROE reflects the cost of raising and retaining equity
10 capital and is estimated by using one or more market-based analytical approaches.
11 However, as noted earlier, although quantitative models are used to estimate the
12 ROE, it cannot be precisely quantified through a strict mathematical exercise. As
13 such, a reasonable and appropriate ROE reflects the financial, economic, and
14 regulatory environment in which the estimate is developed, as well as the subject
15 company's relative risk profile.
16
17 **Q16. Please summarize the guiding principles used in establishing the cost of capital**
18 **for a regulated utility.**
19 A16. Public utility regulation is rooted in the principle that utilities are entitled to a fair
20 rate of return sufficient to attract the capital required to provide safe and reliable
21 public utility service for customers at reasonable rates. The U.S. Supreme Court
22 ("Supreme Court") established the guiding principles for establishing a fair rate of
23 return for a public utility in two seminal cases: (1) *Bluefield Water Works and*
24 *Improvement Co. v. Public Service Comm'n.* ("*Bluefield*");[5] and (2) *Federal Power*

5 *See, Bluefield Water Works and Improvement Co. v. Public Service Comm'n.*, 262 U.S. 679, 692 (1923).

1 *Comm'n v. Hope Natural Gas Co.* ("*Hope*").[6] In *Bluefield*, the Supreme Court
2 stated:

3 *A public utility is entitled to such rates as will permit it to earn a return*
4 *upon the value of the property which it employs for the convenience of*
5 *the public equal to that generally being made at the same time and in the*
6 *same general part of the country on investments in other business*
7 *undertakings which are attended by corresponding risks and*
8 *uncertainties; but it has no constitutional right to profits such as are*
9 *realized or anticipated in highly profitable enterprises or speculative*
10 *ventures. The return should be reasonably sufficient to assure*
11 *confidence in the financial soundness of the utility and should be*
12 *adequate, under efficient and economical management, to maintain and*
13 *support its credit, and enable it to raise the money necessary for the*
14 *proper discharge of its public duties.*[7]

15

16 In *Hope*, the Supreme Court reiterated the three primary standards for a regulated
17 rate of return:

18 *From the investor or company point of view it is important that there be*
19 *enough revenue not only for operating expenses but also for the capital*
20 *costs of the business. These include service on the debt and dividends*
21 *on the stock…By that standard the return to the equity owner should be*
22 *commensurate with returns on investments in other enterprises having*
23 *corresponding risks. That return, moreover, should be sufficient to*
24 *assure confidence in the financial integrity of the enterprise, so as to*
25 *maintain its credit and to attract capital.*[8]

26 In summary, the Supreme Court has recognized that the fair rate of return on equity
27 should be: (1) commensurate with returns investors expect to earn on other
28 investments of similar risk (the "comparable return" standard); (2) sufficient to
29 assure confidence in the company's financial integrity (the "financial integrity"
30 standard); and (3) adequate to maintain and support the company's credit and to

6 *See, Federal Power Comm'n v. Hope Natural Gas Co*., 320 U.S. 591, 603 (1944).
7 *Bluefield Water Works and Improvement Co. v. Public Service Comm'n*., 262 U.S. 679, 692 (1923).
8 *Federal Power Comm'n v. Hope Natural Gas Co*., 320 U.S. 591, 603 (1944).

1 attract capital (the "capital attraction" standard). Importantly, a fair and reasonable
2 return satisfies all three of these standards.
3
4 **Q17. Has the Commission also applied the *Hope* and *Bluefield* standards as**
5 **guidance for setting rates?**
6 A17. Yes. For example, in its Order in Case No. U-21534, the Commission stated:

7 *The criteria for establishing a fair ROE for public utilities is rooted in*
8 *the language of the landmark United States Supreme Court cases*
9 *Bluefield Waterworks & Improvement Co v Pub Serv Comm of West*
10 *Virginia, 262 US 679; 43 S Ct 675; 67 L Ed 1176 (1923) and Fed Power*
11 *Comm v Hope Natural Gas Co, 320 US 591; 64 S Ct 281; 88 L Ed 333*
12 *(1944).*[9]

13 Additionally, the Commission recognized that the determination of a fair and
14 reasonable ROE "is not subject to mathematical computation with scientific
15 exactitude but depends on a comprehensive examination of all factors involved
16 having in mind the objective sought to be attained in its use."[10]
17
18 Based on those standards, the authorized ROE is intended to provide DTE Electric
19 with the *opportunity* (which is not a guarantee) to earn a fair and reasonable return
20 and enable efficient access to external capital under a variety of market conditions.
21
22 **Q18. Why is it important for a utility to be allowed the opportunity to earn a return**
23 **that is adequate to attract capital at reasonable terms?**
24 A18. Regulated utilities have a legal obligation to serve regardless of prevailing
25 economic and capital market conditions. Unlike non-regulated firms, a regulated

---

9 Case No. U-21534, Order, at 200 (January 23, 2025).

10 Case No. U-21534, Order, at 200 (January 23, 2025), *citing*, *Meridian Twp v City of East Lansing, 342 Mich 734, 749*; *71 NW2d 234* (1955).

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1 utility cannot decide to whom it provides utility service in its footprint, how much
2 service it delivers, nor when it provides service. Utility service requires substantial
3 amounts of capital, and a utility must ensure it has access to external financial
4 capital (debt and equity) on cost effective terms to finance its assets not only during
5 times when markets are well-behaving, but also when markets are volatile or
6 constrained (*e.g.*, during periods of high inflation and interest rates, global
7 pandemics, changes in government, and economic recessions). A return that is
8 adequate to attract capital at reasonable terms enables the utility to provide safe and
9 reliable service to customers while maintaining its financial integrity. As discussed
10 above, and in keeping with the *Hope* and *Bluefield* standards, that return must be
11 commensurate with the returns expected for investments of equivalent risk.
12
13 The ratemaking process is based on the principle that, for investors and companies
14 to commit the capital needed to provide safe and reliable utility services, the utility
15 must have the opportunity to recover the return of, and the market-required return
16 on, invested capital. The allowed ROE should enable the subject utility to maintain
17 its financial integrity in a variety of economic and capital market conditions. A
18 return that is adequate to attract capital at reasonable terms enables the utility to
19 provide safe, reliable service to customers while maintaining its financial soundness.
20
21 Further, the financial community carefully monitors utility companies' current and
22 expected financial conditions, including the regulatory environment in which those
23 companies operate. In that respect, the regulatory environment is one of the most
24 important factors considered in both debt and equity investors' assessments of risk.[11]

11 *See, e.g.*, Moody's Ratings, *Rating Methodology: Regulated Electric and Gas Utilities*, August 6, 2024, at 2.

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1 That consideration is especially important during uncertain economic and financial
2 conditions in which the utility may require access to capital markets.
3
4 The outcome of the Commission's order in this case, therefore, must provide DTE
5 Electric with the opportunity to earn an ROE that is: (1) adequate to attract capital
6 at reasonable terms; (2) sufficient to ensure its financial integrity; and (3)
7 commensurate with returns on investments in enterprises having corresponding
8 risks. Providing DTE Electric with a reasonable opportunity to earn its market-
9 based cost of equity ensures that customers receive safe and reliable service at a
10 reasonable cost in all market environments.
11
12 **Q19. What are your conclusions regarding the regulatory principles pertaining to**
13 **the cost of capital for a public utility?**
14 A19. Congruent with other costs in a utility's cost of service, the regulated return on rate
15 base is a cost that DTE Electric incurs as part of its normal operations, including
16 the need to compensate equity investors for the use of their capital. Under the *Hope*
17 and *Bluefield* standards, the cost of equity authorized for DTE Electric in this
18 proceeding should be (1) adequate to attract capital at reasonable terms;
19 (2) sufficient to ensure its financial integrity; and (3) commensurate with returns on
20 investments in enterprises having corresponding risks.
21
22 Because utilities are capital intensive and investors have many investment
23 alternatives, the Company's financial profile must be adequate on a relative basis to
24 ensure its ability to attract capital under a variety of economic and financial market
25 conditions. The Commission's decision regarding the authorized ROE and capital

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1 structure in this proceeding will directly affect the Company's ability to attract the
2 capital needed to maintain and enhance service to customers.
3
4 Proxy Group Selection
5 **Q20. Why is it necessary to select a group of proxy companies to determine the cost**
6 **of equity for DTE Electric?**
7 A20. Because the ROE is a market-based concept, and DTE Electric is not a separate
8 entity with its own stock price, it is necessary to establish a group of companies that
9 are both publicly traded and comparable to the Company in certain fundamental
10 respects to serve as its "proxy" in the ROE estimation process. Even if the
11 Company were a publicly traded entity, short-term events could bias its market
12 value during a given period. A significant benefit of using a proxy group is that it
13 moderates the effects of anomalous, temporary events associated with any one
14 company. As a result of the screening criteria used to select the proxy group, the
15 companies used in my ROE analyses have similar business and operating
16 characteristics to DTE Electric and thus provide a reasonable basis for the
17 derivation and assessment of ROE estimates.
18
19 **Q21. Please provide a summary profile of DTE Electric.**
20 A21. DTE Electric is an indirect wholly owned subsidiary of DTE Energy. DTE Electric
21 is engaged in the generation, purchase, distribution, and sale of electricity to
22 approximately 2.3 million customers in southeastern Michigan.[12] The Company's
23 generation fleet consists primarily of two coal-fired plants, a combined cycle

12 DTE Energy SEC Form 10-K, at 6 (December 31, 2025).

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1 natural gas plant, a hydroelectric pumped storage plant, a nuclear plant, and wind
2 and solar assets.[13]
3
4 The Company's current long-term issuer credit ratings are as follows:
5 **Table 2 DTE Electric's Long-Term Issuer Credit Ratings[14]**
6
7

Rating Agency	Current Credit Rating	Outlook
S&P Global Ratings ("S&P")	A-	Stable
Moody's Ratings ("Moody's")	A2	Negative
Fitch Ratings ("Fitch")	A-	Stable

8
9
10
11
12
13 **Q22. How do you select the companies included in your proxy group?**
14 A22. Because estimating the cost of equity is a comparative exercise, it is necessary to
15 develop a proxy group of companies with risk profiles that are reasonably
16 comparable to the subject company. As each company is unique, no two companies
17 will have identical business and financial risk profiles. In selecting a proxy group,
18 my objective is to balance the competing interests of selecting companies that are
19 representative of the risks and prospects faced by DTE Electric, while at the same
20 time ensuring that there is a sufficient number of companies in the proxy group. To
21 develop my proxy group, I began with the 36 domestic companies that *Value Line*
22 classifies as Electric Utilities and applied the following screening criteria:

13 DTE Energy SEC Form 10-K, at 7 (December 31, 2025).
14 Sources: S&P, Moody's, and Fitch as of March 31, 2026.

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1. Because certain of the models used in my analyses assume that earnings and dividends grow over time, I exclude companies that do not consistently pay quarterly cash dividends or cut their dividend in the last two years;
2. I exclude companies that do not have (or its primary regulated electric utility subsidiary does not have) an investment-grade issuer or senior unsecured bond credit rating from S&P and Moody's;
3. To ensure that the growth rates used in my analyses are not biased by a single analyst, all the companies in my proxy group are consistently covered by at least two utility industry equity analysts;
4. Because certain of the models assume that earnings grow over time, I exclude companies that do not have positive earnings growth rates from at least two sources;
5. Because DTE Electric owns generation, I exclude companies that are not vertically integrated;
6. To incorporate companies that are primarily regulated electric utilities, I first exclude companies that have less than 60 percent of net operating income from regulated operations, on average over the three years ended 2024. I then exclude companies within this group that have less than 60 percent of total regulated operating income from regulated electric operations, on average, over the three years ended 2024;
7. I eliminate companies that have had a recent significant merger activity or transactions or a recent significant financial event that could affect its market data or financial condition; and

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1 8. To avoid any circularity concerns, I exclude the Company's parent
2 company, DTE Energy, from my proxy group.
3
4 **Q23. Which companies meet your screening criteria?**
5 A23. The criteria discussed above result in a proxy group of the following 18 companies:
6

Table 3 Proxy Group Screening Results

Company	Ticker
Alliant Energy Corporation	LNT
Ameren Corporation	AEE
American Electric Power Company, Inc.	AEP
Avista Corporation	AVA
CMS Energy Corporation	CMS
Dominion Energy, Inc.	D
Duke Energy Corporation	DUK
Entergy Corporation	ETR
Evergy, Inc.	EVRG
FirstEnergy Corporation	FE
IDACORP, Inc.	IDA
NextEra Energy, Inc.	NEE
OGE Energy Corporation	OGE
Pinnacle West Capital Corporation	PNW
Portland General Electric Company	POR
PPL Corporation	PPL
Southern Company	SO
Xcel Energy Inc.	XEL

7
8 **Q24. Do your screening criteria result in a group of companies that investors would**
9 **view as comparable to DTE Electric?**
10 A24. Yes. The proxy group has been selected to develop a group of companies that are
11 reasonably comparable (but not identical) to the financial and operational

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1 characteristics of DTE Electric in aggregate. The screening criterion requiring an
2 investment grade credit rating ensures that the proxy companies, like the Company,
3 are generally in sound financial condition. Additionally, the criterion based on the
4 percentage of net operating income from regulated electric operations distinguishes
5 between electric utilities that are subject to regulation and those with substantial
6 unregulated operations that are exposed to higher risks. In my opinion, these
7 screens collectively reflect key risk factors that investors consider in making
8 investments in electric utilities.
9
10 Cost of Equity Models
11 **Q25. What analytical approaches do you rely on to determine the Company's ROE?**
12 A25. As discussed earlier, I rely on the constant growth and quarterly growth forms of
13 the DCF model, the traditional and empirical forms of the CAPM, and the Risk
14 Premium approach. The models I apply are commonly used in practice, as well as
15 in regulatory proceedings.[15] Additionally, each model provides a different
16 perspective of investors' views of risk and return. Therefore, using multiple
17 methods provides a more comprehensive and reliable perspective on investors'
18 return requirements.
19
20 **Constant Growth Discounted Cash Flow Model**
21 **Q26. Please describe the Constant Growth DCF approach.**
22 A26. The Constant Growth DCF model is based on the theory that a stock's current price
23 represents the present value of all expected future cash flows. In its simplest form,
24 the Constant Growth DCF model expresses the cost of equity shown in Equation

15 *See, for example,* Eugene Brigham, Louis Gapenski, Financial Management: Theory and Practice, 7th Ed., 1994, at 341.

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[1] below, which sets the ROE equal to the expected dividend yield plus the expected long-term annual growth rate in perpetuity:

$$k = \frac{D_0\ (1+g)}{P} + g \qquad [1]$$

where:

k = the required market cost of equity,

D_0 = the current annualized dividend,

P = the current stock price, and

g = the expected long-term annual growth rate.

Q27. What assumptions underlie the Constant Growth DCF model?

A27. The Constant Growth DCF model assumes: (1) a constant average annual growth rate for earnings and dividends; (2) a stable dividend payout ratio; (3) a constant Price/Earnings multiple; and (4) a discount rate greater than the expected growth rate. The model also assumes that the current cost of equity remains constant in perpetuity.

Q28. What market data do you use as inputs to your Constant Growth DCF analysis?

A28. I calculate the Constant Growth DCF result for each of the proxy companies using the following inputs:

- The average daily closing prices for the 30-, 90-, and 180-trading days ended January 30, 2026, for the term P;
- The current quarterly dividend as of January 30, 2026 multiplied by 4, for the term D_0; and

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- Long-term earnings per share ("EPS") growth rate projections as of January 30, 2026, reported by Zacks, S&P Capital IQ Pro, and *Value Line*.

Q29. Why do you use three averaging periods to calculate an average stock price?

A29. I do so to ensure that the model's results are not skewed by anomalous events that may affect stock prices on any given trading day. At the same time, the averaging period should be reasonably reflective of expected capital market conditions over the long term. Using 30-, 90-, and 180-trading day averaging periods balances those concerns.

Q30. How do you calculate the expected dividend yield over the coming year?

A30. Because utility companies tend to increase their quarterly dividends at different times throughout the year, it is reasonable to assume that dividend increases will be evenly distributed over calendar quarters. Given that assumption, it is appropriate to calculate the expected dividend yield by applying one-half of the long-term growth rate to the current dividend yield. That adjustment ensures that the expected dividend yield is, on average, representative of the coming 12-month period.

Q31. Why is projected EPS growth the appropriate measure of long-term growth in the Constant Growth DCF model?

A31. In its Constant Growth form, the DCF model (*i.e.*, as presented in Equation [1] above) assumes a single expected growth estimate in perpetuity, which assumes a fixed payout ratio, and the same constant growth rate in EPS, dividends per share, and book value per share. In the long run, dividend growth can only be sustained by earnings growth.

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1 Further, academic studies have clearly and consistently shown that measures of
2 earnings and cash flow are strongly related to returns, and that analysts' forecasts of
3 growth are superior to other measures of growth in predicting stock prices.[16] For
4 example, the research of Vander Weide and Carleton demonstrates that earnings
5 growth projections have a statistically significant relationship to stock valuation
6 levels, while dividend growth rates do not.[17] An academic study from The Journal
7 of Portfolio Management found that securities analysts' growth estimates have been
8 shown to be more accurate predictors of future returns than historical earnings and
9 dividend growth rates, as well as sustainable growth rates.[18] Additionally, a 2002
10 study in the Journal of Accounting Research examined "the valuation performance
11 of a comprehensive list of value drivers" and found that "forward earnings explain
12 stock prices remarkably well" and were generally superior to other value drivers
13 analyzed.[19] A 2013 study from the journal Contemporary Accounting Research
14 found that the sell-side analysts with the most accurate stock price targets were those
15 whom the researchers found to have more accurate earnings forecasts.[20] Further,

---

16 *See, e.g.*, Andreas C. Christofi, Petros C. Christofi, Marcus Lori and Donald M. Moliver, *Evaluating Common Stocks Using Value Line's Projected Cash Flows and Implied Growth Rate*, Journal of Investing (Spring 1999); Harris and Marston, *Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts*, Financial Management at 69 (Summer 1992); and Vander Weide and Carleton, *Investor Growth Expectations: Analysts vs. History*, The Journal of Portfolio Management (Spring 1988); Robert S. Harris, *Using Analysts' Growth Forecasts to Estimate Shareholder Required Rate of Return*, Financial Management at 66-67 (Spring 1986).

17 *See* Vander Weide and Carleton, *Investor Growth Expectations: Analysts vs. History*, The Journal of Portfolio Management (Spring 1988).

18 David A. Gordon, Myron J. Gordon & Lawrence I. Gould, *Choice Among Methods of Estimating Share Yield*, The Journal of Portfolio Management, Spring 1989.

19 Liu, Jing, et al., *Equity Valuation Using Multiples*, Journal of Accounting Research, Vol. 40 No. 1, March 2002.

20 Gleason, C.A., et al., *Valuation Model Use and the Price Target Performance of Sell Side Equity Analysts*, Contemporary Accounting Research, Vol. 30 No. 1, (Spring 2013).

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1 academic studies suggest that investors base their investment decisions on analysts'
2 expectations of growth in earnings.[21]
3
4 Lastly, the only forward-looking growth rates that are available on a consensus basis
5 are analysts' EPS growth rates. The fact that earnings growth projections are the
6 only widely available estimates of growth further supports the conclusion that
7 earnings growth is the most meaningful measure of growth among the investment
8 community. For these reasons, earnings growth is the appropriate measure of long-
9 term growth in the DCF model.
10
11 **Q32. What are the results of your Constant Growth DCF analysis?**
12 A32. To provide a spectrum of DCF-based ROE estimates, I calculate the low, mean,
13 and high Constant Growth DCF result. The mean result combines the average of
14 the three EPS growth rate estimates with each proxy company's expected dividend
15 yield. The high DCF result adds the maximum EPS growth rate estimate with each
16 proxy company's expected dividend yield. Similarly, the low DCF result adds the
17 minimum EPS growth rate estimate for each proxy company to the expected
18 dividend yield. I then calculate the mean and median low, mean, and high DCF
19 results for the proxy group. In developing my ROE recommendation, I rely on the
20 average of the mean and median proxy group Constant Growth DCF results (*see*
21 Table 4, below, and Exhibit A-14 Schedule D5.2). By relying on the average of

21 *See*, *e.g.*, Harris and Marston, *Estimating Shareholder Risk Premia Using Analysts Growth Forecasts,* Financial Management, Summer 1992, at 65; and Vander Weide and Carleton, *Investor Growth Expectations: Analysts vs. History*, The Journal of Portfolio Management, Spring 1988, at 81. Please note that while the original study was published in 1988, it was updated in 2004 under the direction of Dr. Vander Weide. The results of that updated study are consistent with Vander Weide and Carleton's original conclusions.

Line No.

1 the mean and median proxy group results, I consider the individual DCF results of
2 each proxy company while mitigating the effect of the highest and lowest estimates.
3
4 **Table 4 Constant Growth DCF Results[22]**

	Low	Mean	High
30-Day Average	9.64%	10.67%	11.57%
90-Day Average	9.59%	10.63%	11.54%
180-Day Average	9.68%	10.70%	11.66%

5
6 **Quarterly Growth Discounted Cash Flow Model**
7 **Q33. Please briefly describe the Quarterly Growth DCF model.**
8 A33. As noted earlier, the Constant Growth DCF model is based on several limiting
9 assumptions, one of which is that dividends are paid annually. However, most
10 dividend-paying companies, including utilities, pay dividends on a quarterly (as
11 opposed to an annual) basis. Although the dividend yield adjustment discussed
12 earlier is meant to address that assumption (by increasing the current dividend yield
13 by one-half of the expected growth rate), it does not fully account for the quarterly
14 receipt and reinvestment of dividends. Consequently, the Constant Growth DCF
15 model likely understates the cost of equity.
16
17 The Quarterly Growth DCF model specifically incorporates investors' expectations
18 of the quarterly payment of dividends, and the associated quarterly compounding
19 of those dividends as they are reinvested at the required ROE. As noted by Dr.
20 Roger Morin:

22 *See*, Exhibit A-14 Schedule D5.2. Average of the proxy group mean and median results.

Line No.

> *Clearly, given that dividends are paid quarterly and that the observed stock price reflects the quarterly nature of dividend payments, the market-required return must recognize quarterly compounding, for the investor receives dividend checks and reinvests the proceeds on a quarterly schedule... The annual DCF model inherently understates the investors' true return because it assumes all cash flows received by investors are paid annually.*[23]

Q34. How is the dividend yield component of the Quarterly Growth DCF model calculated?

A34. To reflect the timing and compounding of quarterly dividends more accurately, the model replaces the "*D*" component of the Constant Growth DCF equation with the following equation:

$$D = d_1 (1+k)^{0.75} + d_2 (1+k)^{0.50} + d_3 (1+k)^{0.25} + d_4 (1+k)^0 \qquad [2]$$

where:

d_1, d_2, d_3, d_4 = expected quarterly dividends over the coming year; and

k = the required market cost of equity.[24]

To calculate the expected dividends over the coming year for the proxy companies (*i.e.*, d_1, d_2, d_3, and d_4), I obtained the last four paid quarterly dividends for each company and multiplied them by one plus the growth rate (*i.e.,* 1 + *g*). For the P_0 component of the dividend yield, I used the same average stock prices applied in the Constant Growth DCF analysis for each proxy company.

Q35. What are the results of your Quarterly Growth DCF analysis?

---

23 Roger A. Morin, Ph.D., New Regulatory Finance, at 344 (2006).

24 Because the required market cost of equity (*k*) is a variable in the dividend yield calculation, the Quarterly Growth DCF model is solved iteratively.

Line No.

A35. My Quarterly Growth DCF results are summarized in Table 5 below (*see also*, Exhibit A-14 Schedule D5.3). As with my Constant Growth DCF results, I rely on the average of the mean and median proxy group results.

Table 5 Quarterly Growth DCF Results[25]

	Low	Mean	High
30-Day Average	9.84%	10.88%	11.83%
90-Day Average	9.78%	10.84%	11.79%
180-Day Average	9.86%	10.95%	11.92%

Capital Asset Pricing Model and Empirical Capital Asset Pricing Model

Q36. Please describe the general form of the CAPM.

A36. The CAPM is a risk premium method that estimates the cost of equity for a given security as a function of a risk-free return plus a risk premium to compensate investors for the non-diversifiable or "systematic" risk of that security. As shown in Equation [3], the CAPM is defined by four components, each of which theoretically is a forward-looking estimate:

$$K_e = r_f + \beta(r_m - r_f) \qquad [3]$$

where:

K_e = the required market cost of equity for a security;

β = the Beta coefficient of that security;

r_f = the risk-free rate of return; and

r_m = the required return on the market as a whole.

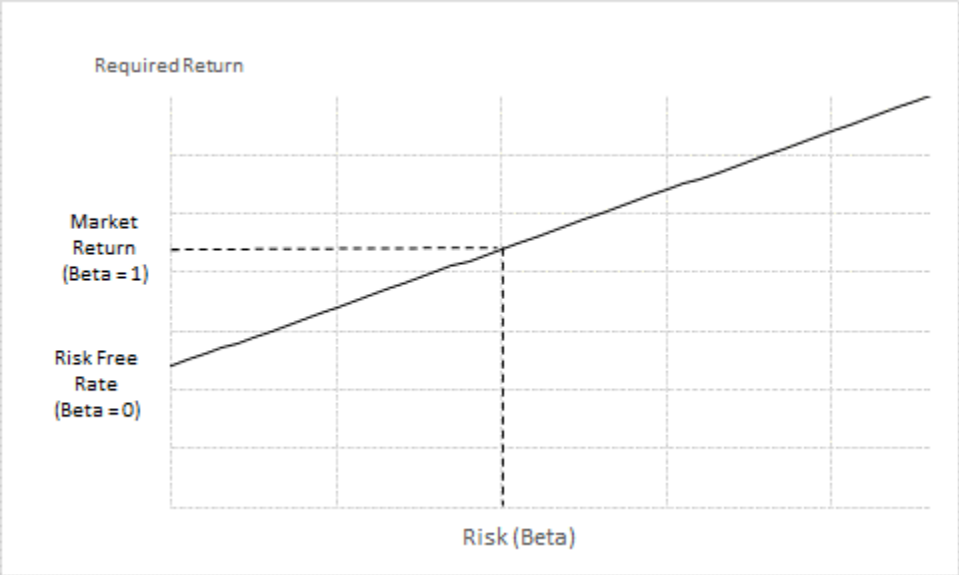
25 *See*, Exhibit A-14 Schedule D5.3. Average of the proxy group mean and median results.

Line No.

1 Equation [3] describes the Security Market Line ("SML"), or the CAPM risk-return
2 relationship, depicted in Figure 3 below. The intercept is the risk-free rate (r_f) that
3 has a Beta coefficient of zero, and the slope is the market risk premium ($r_m - r_f$). As
4 shown in Figure 3, the slope of the line is upward sloping, illustrating the principle
5 that investments of higher risk require a higher return. By definition, r_m, the return
6 on the market, has a Beta coefficient of 1.00.

7

8 **Figure 3. Security Market Line**



9

10 The CAPM assumes that all non-market or unsystematic risk can be eliminated
11 through diversification. The risk that cannot be eliminated through diversification
12 is called market, or systematic, risk. Therefore, the CAPM assumes that investors
13 require compensation only for systematic, or market, risk. Systematic (or non-
14 diversifiable) risk is measured by the Beta coefficient, which is defined as:

Line No.

1 $$\beta_j = \frac{\sigma_j}{\sigma_m} * \rho_{j,m} \quad [4]$$

2 where:

3 β_j = the Beta coefficient of company "*j*";

4 σ_j = the standard deviation of returns for company "*j*";

5 σ_m = the standard deviation of returns for the broad market (as measured,

6 for example, by the S&P 500 Index); and

7 $\rho_{j,m}$ = the correlation of returns between company *j* and the broad market,

8 "*m*".

9

10 The Beta coefficient, therefore, represents both relative volatility (*i.e.*, the standard

11 deviation) of returns, and the correlation in returns between the subject company

12 and the overall market. Intuitively, higher Beta coefficients indicate that the subject

13 company's returns have been relatively volatile and have moved in tandem with the

14 overall market.

15

16 **Q37. What risk-free rates do you assume in your CAPM analysis?**

17 A37. I apply two estimates of the risk-free rate: (1) the current 30-day average yield on

18 30-year Treasury bonds (*i.e.*, 4.83 percent)[26] and (2) a projected 30-year Treasury

19 yield (*i.e.*, 4.68 percent).[27]

20

21 **Q38. Why do you rely on the 30-year Treasury yield as the risk-free rate in your**

22 **CAPM analysis?**

---

26 Source: Federal Reserve Bank of St. Louis (FRED), as of January 30, 2026.

27 The average of: (1) the average projected 30-year Treasury yield for the six quarters ended Q2 2027 and (2) the average long-term projected 30-year Treasury yield for the years 2027-2031 and 2032-2036 reported by *Blue Chip Financial Forecasts. See,* Blue Chip Financial Forecasts, Vol. 45, No. 2, January 30, 2026, at 2 and Blue Chip Financial Forecasts, Vol. 44, No. 12, December 1, 2025, at 14.

Line No.

1 A38. In determining the security most relevant to the application of the CAPM, the term
2 (or maturity) should approximate the life of the underlying investment. Electric
3 utilities are typically long-term investments; therefore, the 30-year Treasury yield
4 is more suitable for the risk-free rate applied in the CAPM.
5
6 **Q39. What Beta coefficients do you use in your CAPM model?**
7 A39. As shown in Exhibit A-14 Schedule D5.5, I rely on two estimates of the Beta
8 coefficient. I first consider the average five-year Beta coefficients from *Value Line*
9 and Bloomberg for each proxy company as of January 30, 2026. Beta coefficients
10 from both services are calculated using weekly returns over a five-year period,
11 adjusted to reflect the tendency of Beta coefficients to regress toward the market
12 mean of 1.00. Second, I consider a version of the CAPM analysis using Bloomberg
13 Beta coefficients calculated using weekly return data over the ten years ended
14 January 30, 2026, rather than a five-year period.
15
16 **Q40. What estimates of the market return do you use to calculate the Market Risk**
17 **Premium?**
18 A40. I apply two estimates of the market return. The first calculates the market
19 capitalization-weighted ROE of the S&P 500 Index by applying the Constant
20 Growth DCF model described earlier to the S&P 500 Index. The second estimate
21 applies the long run historical arithmetic average market return of 12.23 percent
22 between 1926 and 2025 reported by Kroll (formerly Duff & Phelps).[28]

28 Source: Kroll, Cost of Capital Navigator.

Line No.

1 **Q41. Please explain your forward DCF-based approach to estimating the market**
2 **return.**

3 A41. Using the Constant Growth DCF model described earlier, I develop three estimates
4 of the forward market return for the S&P 500 Index. I consider projected earnings
5 growth rates and dividend yields from three sources: (1) S&P's Earnings and
6 Estimates Report; (2) Bloomberg Professional; and (3) *Value Line*, by applying
7 dividend yields from S&P Capital IQ and projected earnings growth rates from
8 S&P, Bloomberg, and *Value Line*. As shown in Table 6 below, these independent
9 estimates of the market return range from 16.38 percent to 19.08 percent (*see also*
10 Exhibit A-14 Schedule D5.4). To be conservative, I rely on *Value Line*'s market
11 return estimate of 16.38 percent in my CAPM analysis.

12

13 **Table 6 DCF-Based Forward Market Return**

Source	Market Return
Value Line	16.38%
Bloomberg Professional	19.08%
S&P Earnings & Estimates Report	18.56%

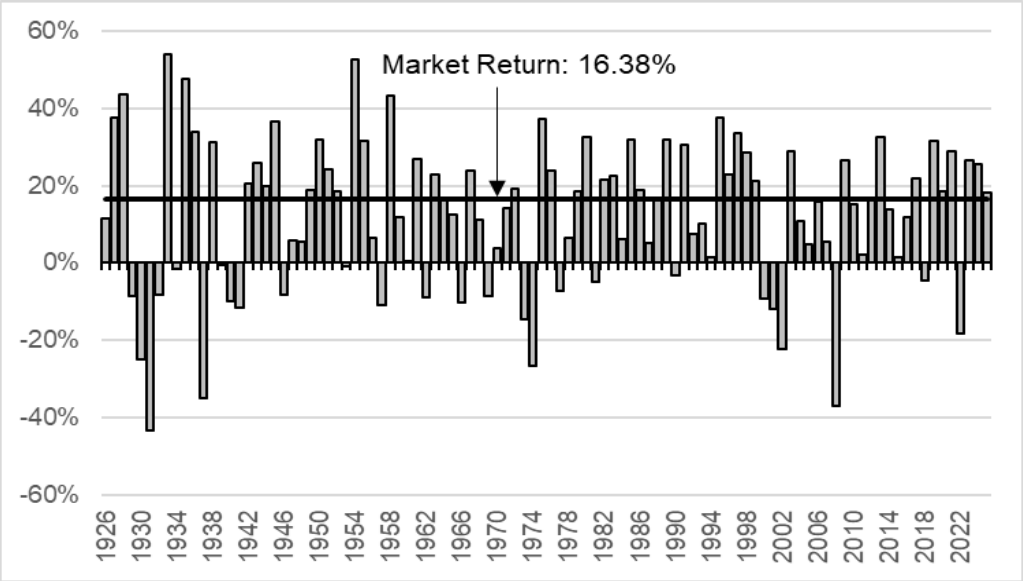
14

15 **Q42. Is the *Value Line* DCF-based market return estimate of 16.38 percent**
16 **consistent with actual observed returns on the market?**

17 A42. Yes, it is. As shown in Figure 4 below, a market return of 16.38 percent or higher
18 occurred in 48 of the last 100 years (*i.e.,* nearly 50 percent of the time). Since 2009,
19 the annual market return has averaged 15.72 percent, and equaled or exceeded
20 16.38 percent in nine of the last 17 years. In other words, an annual market return
21 of 16.38 percent, or higher, has occurred frequently and is not an outlier.

Line No.

1 **Figure 4. Annual Market Return (1926-2025)[29]**



2

3 **Q43. Why do you also consider the long-term arithmetic average historical return**
4 **on the market of 12.23 percent as an alternate estimate of the market return?**

5 A43. My objective is to develop a reasonable estimate of the market return over the long
6 term to calculate a market risk premium. Because the cost of equity is forward
7 looking, any estimate – whether based on historical or projected data – assumes the
8 estimate reflects investors' expectations into the future. Although the 16.38 percent
9 market return is highly consistent with historically observed market returns (as
10 shown in Figure 4 above), it is above the long-term arithmetic annual average
11 market return. Therefore, it may be reasonable to expect that, over the long term,
12 the market return will revert to its long-run historical arithmetic average. From that
13 perspective, the application of the long-run historical arithmetic average market
14 return as an alternate estimate of the market return is prospective in nature.

29 Source: Kroll, 2023 SBBI Yearbook, Appendix A-1, (years 1926-2022); Cost of Capital Navigator (years 2023-2025).

Line No.

1 **Q44. With the risk-free rates and market return estimates described above, how do**
2 **you calculate the market risk premium?**
3 A44. I apply two estimates of the risk-free rate and two estimates of the market return.
4 Combined, those variables produce four estimates of the market risk premium,
5 ranging from 7.40 percent to 11.70 percent, as shown below in Table 7.
6
7 **Table 7 Market Risk Premium Estimates**

	Current Risk-Free Rate (4.83%)	**Projected Risk-Free Rate (4.68%)**
Value Line DCF-based Forward Market Return (16.38%)	11.55%	11.70%
Long-Term Historical Average Market Return (12.23%)	7.40%	7.56%

8
9 **Q45. What are the results of your CAPM analysis?**
10 A45. As shown in Table 8 below, the CAPM results range from 9.77 percent to 13.47
11 percent (*see also*, Exhibit A-14 Schedule D5.5).
12 **Table 8 Summary of CAPM Results[30]**

	Current 30-Year Treasury Yield (4.83%)	**Projected 30-Year Treasury Yield (4.68%)**
DCF-Based Forward Market Return (Average 5-year Beta)	12.62%	12.57%
DCF-Based Forward Market Return (10-year Bloomberg Beta)	13.49%	13.46%
Long-Term Historical Average Market Return (Average 5-year Beta)	9.82%	9.77%
Long-Term Historical Average Market Return (10-year Bloomberg Beta)	10.38%	10.34%

30 *See*, Exhibit A-14 Schedule D5.5.

Line No.

1 **Q46. Do you consider another form of the CAPM?**

2 A46. Yes, I also consider the Empirical CAPM ("ECAPM") approach, which calculates
3 the product of the adjusted Beta coefficient and the Market Risk Premium and
4 applies a weight of 75.00 percent to that result. The model then applies a 25.00
5 percent weight to the Market Risk Premium, without any effect from the Beta
6 coefficient.[31] The results of the two calculations are summed, along with the risk-
7 free rate, to produce the ECAPM result, as noted in Equation [5] below:

8 $$K_e = r_f + 0.75\beta(r_m - r_f) + 0.25(r_m - r_f) \qquad [5]$$

9 where:

10 K_e = the required market cost of equity for a security;

11 β = the Beta coefficient of that security;

12 r_f = the risk-free rate of return; and

13 r_m = the required return on the market as a whole.

14

15 **Q47. What is the benefit of the ECAPM approach?**

16 A47. The ECAPM addresses the tendency of the CAPM to underestimate the cost of
17 equity for companies, such as regulated utilities, with relatively low Beta
18 coefficients. As discussed below, the ECAPM recognizes academic research that
19 indicates the risk-return relationship is flatter than that estimated by the CAPM, and
20 that the CAPM underestimates the Alpha (α), or the constant return term.[32]

21

22 Numerous tests of the CAPM have measured the extent to which security returns
23 and Beta coefficients are related as predicted by the CAPM. The ECAPM method

31 *See*, *e.g.*, Roger A. Morin, New Regulatory Finance, at 189-190 (2006).
32 *Id.*, at 191.

Line No.

1 reflects the finding that the actual SML described by the CAPM formula is not as
2 steeply sloped as the predicted SML.[33] Fama and French state that "[t]he returns on
3 the low beta portfolios are too high, and the returns on the high beta portfolios are
4 too low."[34] Similarly, Dr. Morin states:

5 *With few exceptions, the empirical studies agree that . . . low-beta*
6 *securities earn returns somewhat higher than the CAPM would predict,*
7 *and high-beta securities earn less than predicted.*

8 ***

9 *Therefore, the empirical evidence suggests that the expected return on a*
10 *security is related to its risk by the following approximation:*

11 $$K = R_F + x\,(R_M - R_F) + (1-x)\beta(R_M - R_F)$$

12 *where x is a fraction to be determined empirically. The value of x that*
13 *best explains the observed relationship Return = 0.0829 + 0.0520 β is*
14 *between 0.25 and 0.30. If x = 0.25, the equation becomes:*

15 $$K = R_F + 0.25(R_M - R_F) + 0.75\,\beta(R_M - R_F)$$ [35]

16

17 The relationship between expected returns from the CAPM and ECAPM can be seen
18 in Figure 5 below. This figure uses my current risk-free rate and historical market
19 risk premium and illustrates the extent to which the CAPM understates the expected
20 return relative to the ECAPM when Beta coefficients are less than 1.00.

---

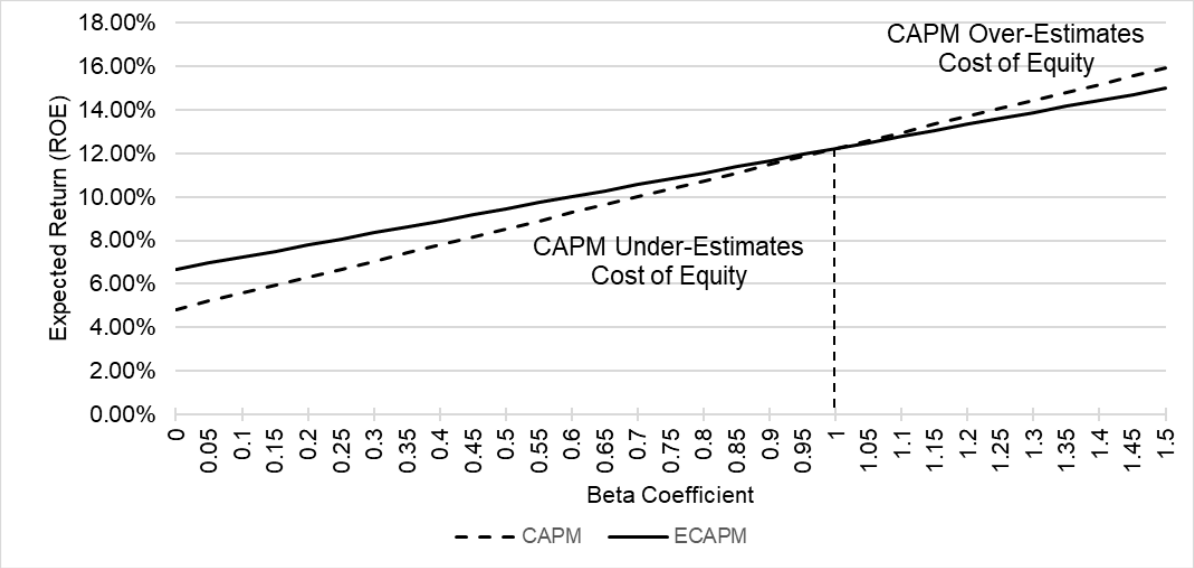
33 Roger A. Morin, Ph.D., New Regulatory Finance, at 175 (2006). The Security Market Line plots the CAPM estimate on the Y-axis, and Beta coefficients on the X-axis.

34 Eugene F. Fama & Kenneth R. French, *The Capital Asset Pricing Model: Theory and Evidence*, Journal of Economic Perspectives, Vol. 18, No. 3, Summer 2004, at 33.

35 Roger A. Morin, New Regulatory Finance, at 175, 190 (2006).

Line No.

1 **Figure 5. CAPM and ECAPM Expected Returns**



2

3 **Q48. Does the use of adjusted Beta coefficients in the ECAPM address the empirical**
4 **issues with the CAPM?**

5 A48. No, it does not. Beta coefficients are adjusted because of their general regression
6 tendency to converge toward 1.00 over time, *i.e.*, over successive calculations. As
7 also noted earlier, numerous studies have determined that at any given point in time,
8 the SML described by the CAPM formula is not as steeply sloped as the predicted
9 SML. To that point, Dr. Morin explains:

10 *Some have argued that the use of the ECAPM is inconsistent with the use*
11 *of adjusted betas, such as those supplied by Value Line and Bloomberg.*
12 *This is because the reason for using the ECAPM is to allow for the*
13 *tendency of betas to regress toward the mean value of 1.00 over time,*
14 *and, since Value Line betas are already adjusted for such trend, an*
15 *ECAPM analysis results in double-counting. This argument is*
16 *erroneous. Fundamentally, the ECAPM is not an adjustment, increase*
17 *or decrease, in beta. This is obvious from the fact that the expected*
18 *return on high beta securities is actually lower than that produced by the*
19 *CAPM estimate. The ECAPM is a formal recognition that the observed*
20 *risk-return tradeoff is flatter than predicted by the CAPM based on*
21 *myriad empirical evidence. The ECAPM and the use of adjusted betas*
22 *comprised two separate features of asset pricing. Even if a company's*

Line No.

> *beta is estimated accurately, the CAPM still understates the return for low-beta stocks. Even if the ECAPM is used, the return for low-beta securities is understated if the betas are understated. Referring back to Figure 6-1, the ECAPM is a return (vertical axis) adjustment and not a beta (horizontal axis) adjustment. Both adjustments are necessary.*[36]

Therefore, it is appropriate to rely on adjusted Beta coefficients in both the CAPM and ECAPM.

Q49. Are you aware of academic studies that support the use of the ECAPM for utilities?

A49. Yes, I am. In a 2011 study by Stéphane Chrétien and Frank Coggins, the authors studied the CAPM's ability to estimate the risk premium for the utility industry in particular subgroups of utilities.[37] The study considered the traditional CAPM approach, the Fama-French three-factor model, and a model similar to the ECAPM. In the study, the ECAPM relied on adjusted Beta coefficients similar to *Value Line*'s approach. As Chrétien and Coggins found, the ECAPM significantly outperformed the traditional CAPM model at predicting the observed risk premium for the various utility subgroups.

Q50. Have any regulatory commissions explicitly accepted the ECAPM?

A50. Yes. The New York Public Service Commission ("NYPSC") relies on both the traditional and empirical forms of the CAPM.[38] Additionally, the North Carolina Utilities Commission ("NCUC") accepted the ECAPM in recent orders for Duke

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36 *Id*., at 191.

37 Stéphane Chrétien and Frank Coggins, *Cost of Equity for Energy Utilities: Beyond The CAPM*, Energy Studies Review, Vol. 18, No. 2 (2011).

38 *See*, New York Public Service Commission, Case 16-G-0058, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of KeySpan Gas East Corporation d/b/a National Grid for Gas Service*, Order Adopting Terms of Joint Proposal and Establishing Gas Rate Plans, December 16, 2016, at 32. The NYPSC refers to the ECAPM as the "zero-beta CAPM."

Line No.

1 Energy Carolinas and Duke Energy Progress.[39] I note that both the NYPSC and
2 NCUC used adjusted Beta coefficients with the ECAPM analysis. Additionally, I
3 am aware that the ECAPM has been accepted by regulatory commissions in Alaska,
4 Maryland, and Mississippi.[40] Lastly, I am aware the ECAPM has been presented
5 by state regulatory commission staff in Maryland, Nevada, and by the Department
6 of Commerce in Minnesota.[41] Consequently, I believe the ECAPM is an accepted
7 approach used by investors and should be accepted by the Commission.
8
9 **Q51. What are the results of your ECAPM analyses?**
10 A51. I apply the same market return estimates, Beta coefficients, and risk-free rates
11 described earlier in my CAPM analysis to Equation [5] above. The results of my
12 ECAPM analyses are summarized in Table 9 below.

---

39 *See*, *In the Matter of Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina and Performance-Based Regulation*, Docket No. E-7, Sub 1276, Order Accepting Stipulations, Granting Partial Rate Increase, Requiring Public Notice, And Modifying Lincoln CT CPCN Conditions, at 209-210; *In the Matter of Application of Duke Energy Progress, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina and Performance-Based Regulation*, Docket No. E-2, Sub 1300, Order Accepting Stipulations, Granting Partial Rate Increase, and Requiring Public Notice, at 162-163.

40 *See,* Regulatory Commission of Alaska, Docket No. P-97-4, Order No. 151, at 146; Maryland Public Service Commission, Case No. 9311, Order No. 85724, at 105; Mississippi Public Service Commission, Docket No. 01-UN-0548, *Notice of Intent of Mississippi Power Company to Change Rates for Electric Service in its Certificated Areas in the Twenty-Three Counties of Southeast Mississippi*, Final Order, December 3, 2001, at 19.

41 *See,* Maryland Public Service Commission, Case No. 9311, Order No. 85724, at 88; Minnesota Public Utilities Commission, MPUC Docket No. G011/GR-15-736, *Findings of Fact, Conclusions of Law, and Recommendation*, August 19, 2016, at 29; Public Utilities Commission of Nevada, Docket No. 12-02019, Second Modified Final Order, at 36.

Line No.

1 **Table 9 Summary of ECAPM Results[42]**

	Current 30-Year Treasury Yield (4.83%)	Projected 30-Year Treasury Yield (4.68%)
DCF-Based Forward Market Return (Average 5-year Beta)	13.56%	13.52%
DCF-Based Forward Market Return (10-year Bloomberg Beta)	14.22%	14.19%
Long-Term Historical Average Market Return (Average 5-year Beta)	10.42%	10.39%
Long-Term Historical Average Market Return (10-year Bloomberg Beta)	10.84%	10.81%

2

3 **Risk Premium Approach**

4 **Q52. Please describe the Risk Premium approach.**

5 A52. The Risk Premium approach is based on the basic financial principle of risk and
6 return, which states that equity investors require a premium over the return required
7 as a bondholder to account for the incremental residual risk associated with equity
8 ownership. Risk premium approaches estimate the cost of equity as the sum of the
9 equity risk premium and the yield on a particular class of bonds.

10

11 **Q53. Please explain how you perform your Risk Premium analysis.**

12 A53. I first define the equity risk premium as the difference between the authorized ROE
13 and the then-prevailing 30-year Treasury bond yield, using the authorized ROE for
14 1,857 electric utility rate proceedings between January 1, 1980 and January 30,
15 2026. To reflect the prevailing level of bond yields during the pendency of the
16 proceedings, I calculate the average 30-year Treasury yield over the average lag

42 *See*, Exhibit A-14 Schedule D5.5.

Line No.

period between the filing of the rate case and the date of the final order (approximately 202 days).

Because the data covers several economic cycles, the analysis is helpful in assessing the change in the equity risk premium over time. Prior research, for example, has shown that the equity risk premium is inversely related to the level of bond yields.[43]

Q54. How do you analyze the relationship between bond yields and the equity risk premium?

A54. I estimate the relationship between bond yields and the equity risk premium by applying a regression analysis, in which the equity risk premium described above is the dependent variable, and the 30-year Treasury yield is the independent variable. To account for the variability in bond yields and authorized ROEs over several decades, I use the semi-log regression, in which the equity risk premium is expressed as a function of the natural log of the 30-year Treasury yield:

$$RP = \alpha + \beta\,(\mathrm{LN}(T_{30})) \qquad [6]$$

where:

RP = the equity risk premium;

T_{30} = the lagged 30-year Treasury bond yield;

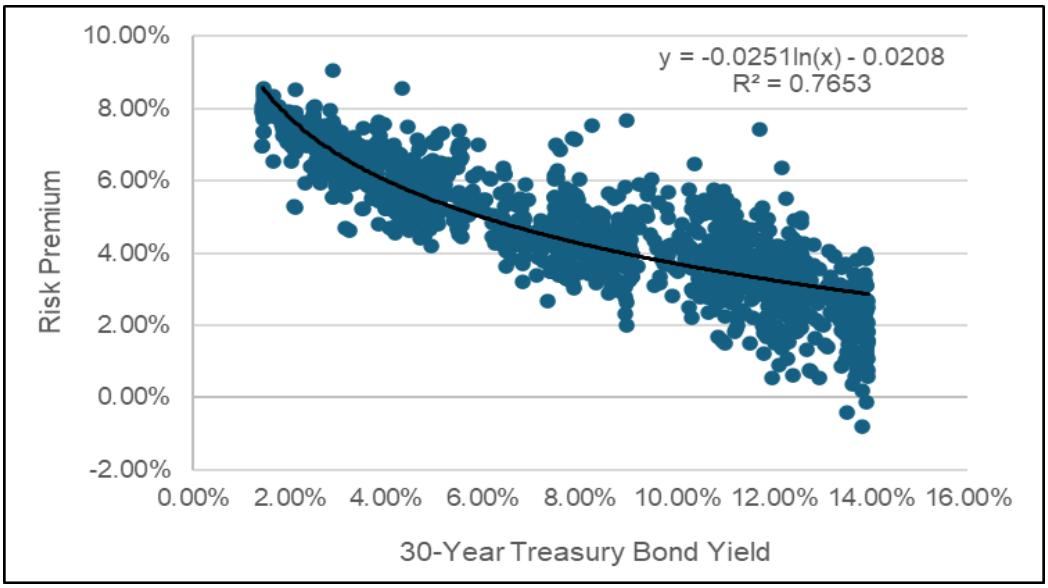
α = the constant term of the regression; and

β = the slope coefficient of the regression.

43 *See, e.g.,* Robert S. Harris and Felicia C. Marston, *Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts*, Financial Management at 63-70 (Summer 1992); Eugene F. Brigham, Dilip K. Shome, and Steve R. Vinson, *The Risk Premium Approach to Measuring a Utility's Cost of Equity*, Financial Management at 33-45 (Spring 1985); and Farris M. Maddox, Donna T. Pippert, and Rodney N. Sullivan, *An Empirical Study of Ex Ante Risk Premiums for the Electric Utility Industry*, Financial Management at 89-95 (Autumn 1995).

Line No.

1 **Figure 6. Equity Risk Premium**[44]



2

3

4 As Figure 6 illustrates, the equity risk premium increases as interest rates fall. The
5 finding that the equity risk premium and interest rates are inversely related is
6 supported by published research. For example, Dr. Morin notes that: "…
7 [p]ublished studies by Brigham, Shome, and Vinson (1985), Harris (1986), Harris
8 and Marston (1992, 1993), Carleton, Chambers, and Lakonishok (1983), Morin
9 (2005), McShane (2005), and others demonstrate that, beginning in 1980, risk
10 premiums varied inversely with the level of interest rates – rising when rates fell and
11 declining when interest rates rose."[45] Based on the regression coefficients in Figure
12 6, the implied ROE is between 10.28 percent and 10.36 percent (*see* Table 10 and
13 Exhibit A-14 Schedule D5.6).

44 *See*, Exhibit A-14 Schedule D5.6.

45 Roger A. Morin, Ph.D., New Regulatory Finance, Public Utilities Reports, Inc., 2006, at 128. (clarification added).

Line No.

1 **Table 10 Summary of Bond Yield Plus Risk Premium Results**[46]

	30-Year Treasury Bond	Risk Premium	Return on Equity
Current 30-Year Treasury	4.83%	5.52%	10.36%
Projected 30-Year Treasury	4.68%	5.61%	10.28%

2

3 **Q55. What are the advantages of the Risk Premium approach?**

4 A55. There are several advantages. First, authorized ROEs in other jurisdictions are a
5 significant part of the market information that investors consider when evaluating
6 their investment alternatives. Therefore, they are a direct measure of returns
7 available to other electric utilities, as required under the comparable return standard
8 of the *Hope* and *Bluefield* decisions. The authorized ROE also provides a signal to
9 investors about the degree of regulatory support that a company can expect with
10 regard to its ability to compete for capital and to ensure its financial integrity. An
11 ROE below its peers for a given period may be an impediment to the Company's
12 ability to attract capital and finance the infrastructure required to provide safe,
13 reliable service to its customers.

14

15 Second, the use of the Risk Premium model in conjunction with the DCF and CAPM
16 approaches adds diversity to the model results, which enables a more robust and
17 reliable ROE estimate. The fewer models that are relied upon, the more likely it is
18 that model risk biases the ultimate ROE determination. For the same reasons that
19 diversity is a wise and prudent investment strategy, diversity of the models used to
20 estimate the ROE is similarly prudent, as it reduces the risk that the results of any
21 single model may not reasonably reflect investors' return requirements.

46 *See*, Exhibit A-14 Schedule D5.6.

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1 A third advantage of the Risk Premium approach is its simplicity and reliance on
2 inputs that are directly observable and less contentious. The Risk Premium
3 approach adds a measure of stability because it is less vulnerable to changes in
4 market data. As shown in the regression equation in Figure 6, the change in the risk
5 premium (and therefore the ROE estimate) as a result of a change in bond yields is
6 less than one-to-one. For example, as shown in Table 10 above, a 15-basis point
7 increase in the bond yield (from 4.68 percent to 4.83 percent) results in an 8-basis
8 point increase in the ROE from 10.28 percent to 10.36 percent.
9
10 **Q56. Is the Risk Premium model circular because it references authorized ROEs?**
11 A56. No. While my Risk Premium analysis is developed by reference to authorized
12 ROEs and the prevailing Treasury yields at the time the regulatory decisions were
13 issued (adjusted for the average length of a rate case), investors' return
14 requirements are informed by allowed ROEs from hundreds of rate case decisions.
15 A fundamental principle in setting a just and reasonable return is that the return
16 must be comparable to returns available from other investments of similar risk. In
17 that regard, the returns that have been authorized for other electric utility companies
18 are highly relevant to investors. Moreover, the use of over 1,800 rate case decisions
19 over the last 46 years mitigates the effect of the unique circumstances of any one
20 rate case. Lastly, commissions are tasked with determining the appropriate
21 regulated return that is based on a utility's cost of equity. In my experience,
22 regulators like this Commission carefully weigh the results of various models that
23 reflect investor behavior and use *market data*. From that perspective, authorized
24 ROEs reflect the commission's informed determination of the utility's market cost

Line No.

of equity. Consequently, the Risk Premium ROE estimates are based on market data and are not circular.

Q57. Do investors use a Risk Premium approach similar to your method?

A57. Yes. As an example, in a December 2023 report from UBS on the utility sector, the investment bank presents a regression analysis which shows that current authorized ROEs are below what would be expected given the historical level of the 10-year Treasury bond yield – *i.e.*, the premise of my Risk Premium analysis.[47]

IV. Business Risks and Other Considerations

Q58. Are there factors specific to DTE Electric's operating environment that you considered in your ROE recommendation?

A58. Yes, there are several additional factors that have a direct bearing on DTE Electric's ability to earn a fair return and on the Company's riskiness relative to the proxy group, including (1) its substantial capital expenditure program, and (2) the regulatory environment in which it operates. Those factors, which are discussed below, should be considered in terms of their overall effect on the Company's business risk and, therefore, its cost of equity.

Capital Expenditure Program

Q59. Do you have any preliminary thoughts on the importance of access to capital for electric utilities such as DTE Electric?

A59. Yes, I do. As a capital-intensive enterprise, the allowed ROE should enable DTE Electric to finance capital expenditures and working capital requirements at

47 UBS, *US Utilities 2024 Outlook: A Year for Resolutions and Resolve*, December 12, 2023, at 10.

Line No.

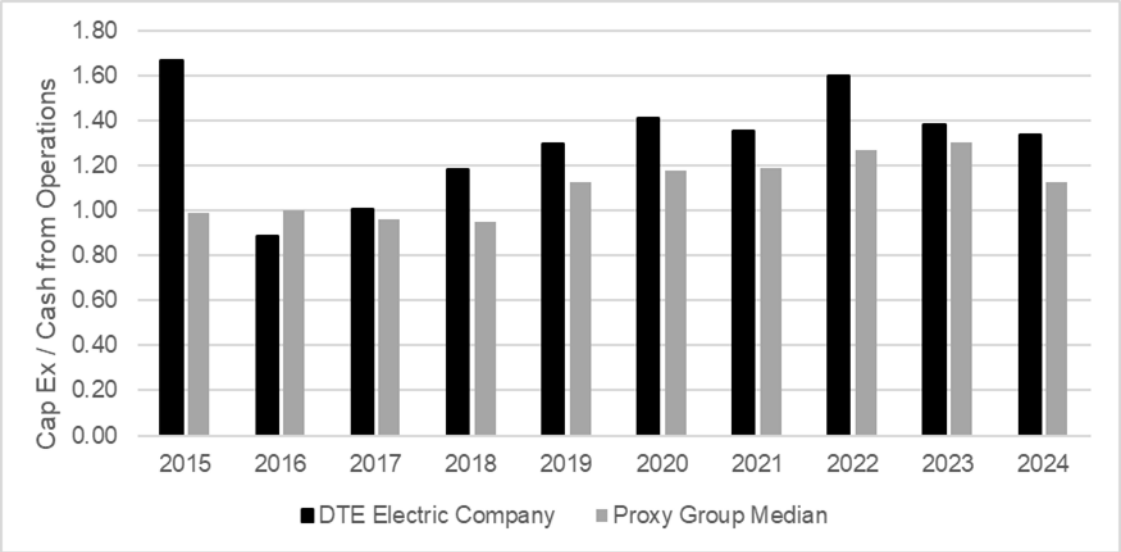
1 reasonable rates and to maintain its financial integrity in a variety of economic and
2 capital market conditions. As discussed throughout my Direct Testimony, a return
3 that is adequate to attract capital on reasonable terms enables a utility to provide
4 safe, reliable service while maintaining its financial soundness to the benefit of
5 customers.
6
7 Electric utilities are one of the most capital-intensive market sectors. On average,
8 electric utilities generate less than 30 percent as much revenue per dollar of assets
9 as the non-utility U.S. companies covered by *Value Line*.[48] To fund the significant
10 capital expenditures needed to maintain, expand, and modernize existing
11 infrastructure, electric utilities require sufficient internally generated cash flow and
12 ongoing access to investor supplied capital. Because electric utilities are often cash
13 flow negative (*i.e.*, cash spent on plant is often more than cash flow received from
14 operations), it is critical that regulation enable timely cost recovery and provide
15 predictable, adequate, and achievable allowed returns that support the financial
16 integrity of the utility.
17
18 As shown in Figure 7 below, the Company's ratio of cash outflows for plant to net
19 cash flow from operations has generally been above 1.0[49] and greater than the proxy
20 group median ratio in nine of the last ten years. Because cash spent on plant is
21 greater than cash received from operations, the Company requires more external
22 capital to finance its capital expenditures than the median proxy company does. In

48 Source: *Value Line*, accessed February 12, 2026.
49 In other words, cash spent on plant is greater than cash received from operations.

Line No.

1 the end, customers benefit from the Company's ability to access external capital on
2 cost effective and favorable terms.

3 **Figure 7. Ratio of Cash Outflow for Plant to Net Cash from Operations (2015 to**
4 **2024)[50]**



5
6
7 **Q60. Please discuss DTE Electric's capital expenditure program.**
8 A60. The Company is planning to invest $30 billion in new generation and reliability
9 capital expenditures over the 2026 to 2030 period that includes approximately $15
10 billion for cleaner generation investments, $11 billion in distribution infrastructure
11 investments, and $4 billion in base infrastructure investments.[51] Company witness
12 Chiu describes DTE Electric's capital investment needs in more detail.
13
14 **Q61. How do DTE Electric's capital expenditure requirements affect its risk**
15 **profile?**

50 Source: S&P Capital IQ.
51 DTE 2025 Year-end Earnings Conference Call Investor Presentation, at 14 (February 17, 2026).

Line No.

A61. As with any utility facing substantial capital expenditure requirements, the Company's risk profile is affected in two significant and related ways: (1) the heightened level of investment increases the risk of under recovery or delayed recovery of the invested capital; and (2) an inadequate return would put downward pressure on key credit metrics due to both the reduction in cash flow and an increase in debt to fund its expenditures.

Q62. Do credit rating agencies recognize the risk associated with increased capital expenditures?

A62. Yes. From a credit perspective, the additional pressure on cash flows associated with high levels of capital expenditures exerts corresponding pressure on credit metrics and, therefore, credit ratings. To that point, S&P explains the importance of regulatory support for large capital projects:

> *When applicable, a jurisdiction's willingness to support large capital projects with cash during construction is an important aspect of our analysis. This is especially true when the project represents a major addition to rate base and entails long lead times and technological risks that make it susceptible to construction delays. Broad support for all capital spending is the most credit-sustaining. Support for only specific types of capital spending, such as specific environmental projects or system integrity plans, is less so, but still favorable for creditors. Allowance of a cash return on construction work-in-progress or similar ratemaking methods historically were extraordinary measures for use in unusual circumstances, but when construction costs are rising, cash flow support could be crucial to maintain credit quality through the spending program. Even more favorable are those jurisdictions that present an opportunity for a higher return on capital projects as an incentive to investors.*[52]

Moody's also notes that increasing capital expenditures are pressuring utility credit profiles by widening cash flow deficits and weakening their financial strength:

52 S&P Global Ratings, *Assessing U.S. Investor-Owned Utility Regulatory Environments*, August 10, 2016, at 7.

Line No.

1 *Credit pressure is emerging most acutely for companies with large,*
2 *complex or multiyear projects or for those that are experiencing a delay*
3 *in the recovery of investment costs. Unlike exogenous events of recent*
4 *years – such as severe storms, commodity price spikes and the COVID-*
5 *19 pandemic, which we viewed as temporary events – capital spending*
6 *and related financings are core long-term financial policy issues.*[53]

7 To the extent that the regulatory environment does not enable timely and sufficient
8 cost recovery of its full cost of doing business, including capital costs, DTE Electric
9 will face increased pressure on its credit metrics, thus raising the cost of both debt
10 and equity. Maintaining the ability to access capital markets on favorable terms, in
11 the form of financial integrity (*i.e.*, capital structure and return on equity), is
12 especially important for utilities and their customers during periods of significant
13 capital investment.

14

15 **Q63. Have the credit rating agencies commented on DTE Electric's elevated capital**
16 **investment program and the effect on its risk?**

17 A63. Yes. On March 30, 2026, Moody's changed the rating outlook of DTE Electric to
18 'Negative' from 'Stable,' due to its elevated capital expenditure program and the
19 associated greater pressure on its credit profile, noting:

20 *The revision of DTE Electric's outlook to negative reflects our*
21 *expectation that the utility's financial profile will face increasing*
22 *pressure during the current elevated capital investment cycle.*

23 ***

24 *While Michigan's regulatory framework remains generally constructive,*
25 *we expect the company's financial metrics to weaken, including a ratio*
26 *of cash flow from operations before changes in working capital (CFO*
27 *pre-WC) to debt that will remain in the 18%–20% range over the next*
28 *few years, which is below our threshold for a potential downgrade of*
29 *21%. In 2025, DTE Electric's CFO pre-WC to debt ratio was 19.6%,*

53 Moody's Ratings, *High capital spending will weigh on credit quality without supportive company actions*, October 21, 2024, at 2.

Line No.

1 *excluding the impact for securitization debt and nuclear*
2 *decommissioning obligations.* [54]

3 S&P noted the Company's elevated capital plan, noting "[c]apital spending remains
4 elevated, and negative discretionary cash flow is likely to persist, which indicates
5 external funding needs."[55]

6

7 **Q64. What is your conclusion regarding the effect of DTE Electric's projected**
8 **capital expenditure program on its risk profile and cost of equity?**

9 A64. DTE Electric is undertaking a substantial capital spending program through (at
10 least) 2030 that will require the Company to maintain access to capital markets on
11 reasonable terms and conditions. Further, DTE Electric requires more external
12 financial capital than the majority of its peers. For these reasons, it is important
13 that the authorized ROE be set at a level that allows DTE Electric to continue to
14 attract both debt and equity under favorable terms under a variety of economic and
15 financial market conditions.

16

17 Regulatory Environment

18 **Q65. Does the regulatory environment influence utilities' access to capital?**

19 A65. Yes it does. The regulatory environment is a key driver of investors' assessment
20 of a utility's risk. Investors and rating agencies understand that a constructive
21 regulatory environment is critical to support utilities' credit ratings and financial
22 integrity, especially during adverse market conditions. Rating agencies also

54 Moody's Ratings, "Moody's Ratings changes DTE Electric's outlook to negative, affirms A2 rating; affirms DTE Energy and DTE Gas ratings with stable outlooks," March 30, 2026.

55 S&P Global Ratings, *DTE Electric Co*., at 1 (March 10, 2026).

Line No.

1 recognize the importance of the regulatory environment when assessing a utility's
2 business risk profile
3
4 Moody's considers the regulatory structure to be so important that 50 percent of the
5 factors that weigh in a ratings determination are related to the nature of
6 regulation.[56] The predictability and consistency of regulatory actions are among
7 the key factors considered by Moody's in assessing the regulatory framework:

8 *As the revenues set by the regulator are a primary component of a*
9 *utility's cash flow, the utility's ability to obtain predictable and*
10 *supportive treatment within its regulatory framework is one of the most*
11 *significant factors in assessing a utility's credit quality. The regulatory*
12 *framework generally provides more certainty around a utility's cash*
13 *flow and typically allows the company to operate with significantly less*
14 *cushion in its cash flow metrics than comparably rated companies in*
15 *other industrial sectors.*

16 ***

17 *In situations where the regulatory framework is less supportive, or is*
18 *more contentious, a utility's credit quality can deteriorate rapidly.*[57]

19
20 S&P states that regulatory advantage is "of critical importance" because "[i]t defines
21 the environment in which a utility operates and has a significant bearing on a utility's
22 financial performance."[58] S&P explains that it considers four subfactors when
23 assessing a utility's ability to recover all its costs "on time and in full – and to earn
24 a return on the capital it deploys."[59] Those four subfactors are (1) regulatory
25 stability, (2) tariff-setting procedures and design, (3) financial stability, and (4)

---

56 Moody's Ratings, *Rating Methodology: Regulated Electric and Gas Utilities,* at 2 (August 6, 2024).

57 Moody's Investors Service, *Regulatory Frameworks – Ratings and Credit Quality for Investor-Owned Utilitie*s, at 2 (June 18, 2010).

58 S&P Global Ratings, *Sector-Specific Corporate Methodology*, Section 29 Regulated Utilities, at 147 (April 4, 2024).

59 *Id*.

Line No.

1 regulatory independence and insulation.[60] With respect to capital expenditures,
2 S&P notes that a regulatory "framework's ability to attract long-term capital, and
3 the availability of capital support during construction," support a utility's financial
4 stability as they "alleviate funding and cash flow pressure when heavy investment
5 is needed."[61] Thus, predictability and consistency of regulatory actions are among
6 the primary concerns for the rating agencies, as is full and timely cost recovery,
7 including recovery of capital costs.
8
9 **Q66. How do the credit rating agencies view the regulatory environment in which**
10 **the Company operates?**
11 A66. The rating agencies view Michigan as a credit supportive regulatory environment
12 and the Company's current credit ratings depend on the continued stability and
13 predictability of Michigan's regulatory environment. In its most recent report in
14 which it revised its outlook for the Company from 'Stable' to 'Negative,' Moody's
15 explains that the Negative outlook reflects its expectation for weaker financial
16 metrics, even as "Michigan's regulatory framework remains generally
17 constructive." [62] Importantly, Moody's also observed that "[o]ver the last two years,
18 the outcomes of DTE Electric's rate cases have been less credit-supportive."[63]
19 Moody's commentary is a signal that it is closely monitoring rate case outcomes
20 for signs that Michigan's historically constructive regulatory environment is
21 weakening. Moody's further noted that DTE Electric could be downgraded "if
22 there is an adverse change in Michigan's regulatory environment, leading to more

60 *Id*.
61 *Id*.
62 Moody's Ratings, Credit Opinion, *DTE Electric Company, Update to credit analysis following outlook change to negative*, at 1 (March 31, 2026).
63 *Id*., at 3.

Line No.

1 contentiousness and a material delay in cost recovery, less transparency, or
2 insufficient cost recovery and returns."[64] Moody's comments emphasize the
3 significance that preserving Michigan's constructive regulatory environment
4 conveys on the Company's credit profile.
5
6 **Q67. Have you compared DTE Electric's regulatory risk relative to the electric**
7 **utilities within the proxy group?**
8 A67. Yes, I have. To assess the regulatory environment of the proxy companies and DTE
9 Electric, I reviewed the key cost recovery mechanisms and ratemaking frameworks
10 for each of the electric operating companies within the proxy group in the
11 jurisdictions in which they operate, including the cost recovery and volumetric risk
12 mitigation mechanisms in place, test year, and rate base methodology.
13
14 As shown in Exhibit A-14 Schedule D5.7 Revised, like DTE Electric, all the proxy
15 group operating companies with retail supply obligation have a fuel and/or
16 purchased power cost recovery mechanism, 83 percent have a mechanism to recover
17 energy efficiency program costs, and 68 percent have a capital cost recovery
18 mechanism. Further, 55 percent of the jurisdictions in which the proxy companies
19 operate allow a full or partial forecast test year like the Company. However, unlike
20 56 percent of the proxy group, DTE Electric does not have a mechanism to mitigate
21 volumetric risk, such as revenue decoupling or a lost revenue adjustment mechanism
22 for its energy efficiency programs. Further, 56 percent of the jurisdictions in which
23 the proxy companies operate use year-end rate base, unlike the Company.

64 *Id.*, at 2.

Line No.

1 From an investor perspective, the Company's regulatory mechanisms do not offer
2 any level of risk mitigation that is meaningfully different from the proxy companies.
3 Furthermore, these regulatory mechanisms are only as effective as their
4 implementation, including a compensatory return. It is in customers' best interest
5 that the regulatory environment in Michigan be viewed as predictable, balanced, and
6 supportive of utility investment.
7
8 **Q68. The Commission recently approved a performance-based ratemaking**
9 **("PBR") mechanism for the Company.[65] Does this PBR mechanism reduce**
10 **DTE Electric's risk?**
11 A68. No, it does not. This PBR mechanism provides DTE Electric an opportunity to
12 earn an incentive of up to $10 million per year, though the Company could also
13 incur a penalty of up to $10 million per year, based on its performance across
14 several reliability metrics.[66] This PBR mechanism does not reduce DTE Electric's
15 risk because the incentive and penalty structures feature deadbands that are not
16 centered on the performance targets and require that all Service Reliability and
17 Quality Standards targets must be satisfied for the company to receive a net
18 incentive through the PBR mechanism. These provisions make it challenging for
19 the Company to earn an incentive, but easy for the Company to incur a penalty.
20 This is even true during particularly severe storm seasons, of which DTE does not
21 control the frequency nor severity. Despite this increased risk, I do not make an
22 adjustment to my recommended ROE based on this PBR mechanism.

---

65 *In the matter of the application of DTE Electric Company for approval to implement a performance-based ratemaking mechanism*, Order Approving Settlement Agreement, Case No. U-21909, December 18, 2025.

66 *Id*., Settlement Agreement section, at 5-6.

Line No.

1 **Q69. Do the Company's regulatory mechanisms reduce its risk relative to its peers?**

2 A69. No, they do not. While DTE Electric's regulatory mechanisms may serve to reduce
3 its *absolute* level of risk, the cost recovery mechanisms employed by the Company
4 are similar to those used by the proxy group; as such, its risk *relative* to the proxy
5 group is not reduced due to its rate structures. In other words, the Company's
6 regulatory mechanisms are credit supportive, but not necessarily credit enhancing
7 relative to its peers. Further, because the proxy companies all have similar
8 mechanisms, investors' views regarding the effects on the cost of equity associated
9 with the rate mechanisms are implicitly reflected in the analytical model results.

10

11 It is important to remember that risk assessment is a comparative exercise. Risk
12 reducing regulatory mechanisms are common in the utility industry, and the
13 financial community is fully aware of their prevalence. As noted earlier, the proxy
14 companies have similar mechanisms as DTE Electric. While the specific details of
15 the mechanics of the rate adjustment mechanisms may differ from utility to utility
16 and jurisdiction to jurisdiction, their objective is the same - to improve the timeliness
17 of cost recovery and mitigate (but not necessarily eliminate) earnings erosion
18 associated with regulatory lag. Because the proxy companies all have mechanisms
19 that improve the timeliness of cost recovery, the Company's regulatory mechanisms
20 simply render it more comparable to its peers. Therefore, there is no reduction in
21 the Company's risk, or its ROE, on account of its regulatory mechanisms.

22

23 **Q70. What are your conclusions regarding the effect of the Company's capital**
24 **expenditure plans, its need to maintain access to capital, and the regulatory**
25 **environment on its risk profile?**

Line No.

1 A70. The Company's capital expenditure program reflects a significant increase of its net
2 plant in service and places increased pressure on its cash flows, making regulatory
3 support critical to DTE Electric's ability to finance and earn a reasonable return on
4 its planned utility investments. The Company's capital expenditure plan emphasizes
5 the importance of the Commission's decision in this proceeding, which will have a
6 direct bearing on the Company's ability to maintain its financial profile and its
7 access to the capital market at reasonable costs and terms.
8
9 The Company will need to rely on external sources of capital to fund critical
10 generation and distribution investments to meet DTE Electric's significant
11 distribution system requirements. In order to maintain access to external capital at
12 reasonable costs and terms for customers in all market environments, the Company
13 must have a reasonable opportunity to recover its full cost of service, including
14 timely cost recovery of its capital investments and a competitive and compensatory
15 return.
16
17 **V. <u>Capital Structure</u>**
18 **Q71. What is DTE Electric's requested capital structure?**
19 A71. As explained by Company witness Timothy Lepczyk, the Company is requesting a
20 permanent capital structure consisting of 51.50 percent equity and 48.50 percent
21 long-term debt. I understand that these figures correspond to the Company's
22 projected actual capital structure.
23
24 **Q72. How does capital structure affect the cost of capital?**

Line No.

1 A72. A company's total risk consists of business risk and financial risk. Business risk
2 includes operating, market, regulatory, and competitive uncertainties, while
3 financial risk is the incremental risk to investors associated with additional
4 leverage, or levels of debt. Therefore, the capital structure indicates a company's
5 financial risk, which reflects the risk that a company may not have adequate cash
6 flows to meet its financial obligations.
7
8 As the percentage of debt in the capital structure increases, so do the fixed
9 obligations for the repayment of that debt and the risk of financial distress.[67] In
10 essence, even if two firms face the same business risks, a company with
11 meaningfully higher levels of debt in its capital structure is riskier, which increases
12 its costs of both debt and equity.
13
14 **Q73. Please summarize the approaches to determining the appropriate capital**
15 **structure for regulated utilities.**
16 A73. There are two primary approaches regulators use to determine the appropriate
17 capital structure for ratemaking purposes. The most common approach is to use
18 the subject utility's actual[68] capital structure. This approach is preferred when the
19 subject utility (1) issues its own debt, (2) has its own credit rating, and (3) its actual
20 capital structure is within industry standards and practice. When the subject utility
21 does not issue its own debt and have its own credit rating, or when the actual capital
22 structure deviates substantially from industry practice, a hypothetical capital
23 structure may be imputed.

---

67 *See,* Roger A. Morin, Ph.D., New Regulatory Finance, Public Utility Reports, Inc. at 45-46 (2006).

68 As used in this case, a utility's actual capital structure refers to the capital structure that DTE Electric includes in its projected test year.

Line No.

1 **Q74. Does DTE Electric issue its own debt and have its own credit rating?**

2 A74. Yes. Therefore, the next step is to assess the reasonableness of its actual capital
3 structure within the context of industry practice.

4

5 **Q75. What are the regulatory guidelines for determining whether a utility's capital**
6 **structure is consistent with sound utility practice?**

7 A75. In a 2020 publication titled *A Cost of Capital and Capital Markets Primer for*
8 *Utility Regulators*, NARUC advises that actual capital structure ratios should be
9 used unless they "greatly diverge" from sound industry practice:

10 *A utility management must be permitted latitude, discretion, and*
11 *flexibility in managing capital structure ratios. Since there is no*
12 *practical methodology to pinpoint theoretically optimal capital structure*
13 *ratios, targeted ratios can only be broadly conceptualized. Appropriate*
14 *ratios may shift over time as capital market conditions or business risk*
15 *characteristics change. Additionally, the timing of upcoming issuances*
16 *and maturities may influence the capital structure ratios because both*
17 *the size and frequency of issuances are affected by the relative cost-*
18 *effectiveness of various issuance increments.*

19 *Given these practical considerations, capital structure ratios cannot be*
20 *deemed to be inappropriate unless the ratios greatly diverge from sound*
21 *industry practice and cause a lack of financial flexibility that may lead*
22 *to higher overall costs.*

23 ***

24 *As increasing financial leverage shifts the weight from common equity*
25 *to lower cost debt, it also increases both the cost of debt and the cost of*
26 *common equity. In practice, these offsetting impacts cancel each other*
27 *out over a wide range of capital structure ratios, so hypothetical capital*
28 *structures that micro-manage a utility's capital structure ratios by a 1%*
29 *or 5% increment offer minimal opportunity to actually reduce the*
30 *WACC.*

31 ***

32 *As a result, financial theory and practice indicate that a regulator has*
33 *little to gain by attempting to micro-manage capital structure ratios*

Line No.

1 *unless they significantly deviate from relevant standards of*
2 *comparison.*[69]

3 Further, James C. Bonbright explains in his seminal text *Principles of Public Utility*
4 *Rates* that a hypothetical capital structure should be used only when actual capital
5 structures are "clearly unsound" or "extravagantly conservative," reasoning that
6 using hypothetical capital structures "substitutes an estimate of what the capital cost
7 would be under non-existing conditions for what it actually is or will soon be under
8 prevailing conditions."[70]
9
10 **Q76. Have you assessed whether DTE Electric's capital structure is consistent with**
11 **sound industry practice?**
12 A76. Yes, I have. The proxy group has been selected to reflect comparable companies
13 in terms of business and financial risks. Therefore, it is appropriate to compare the
14 financial capital structures of the proxy group companies to the financial capital
15 structure requested by DTE Electric in order to assess whether the Company's
16 capital structure is reasonable and consistent with industry standards for companies
17 with commensurate risk. Company witness Lepczyk calculated the average capital
18 structures for each of the proxy group operating companies using the most recent
19 year for which data is available. Exhibit A-14 Schedule D1.1 demonstrates that the
20 Company's projected common equity ratio of 51.50 percent is consistent with, yet
21 somewhat lower than, the proxy group average equity ratio of 53.0 percent.

---

69 NARUC, *A Cost of Capital and Capital Markets Primer for Utility Regulators* (April 2020), at 11-12 (emphasis added).

70 James C. Bonbright, Principles of Public Utility Rates, at 243-44 (1961). Republished with permission by the Regulatory Assistance Project.

Line No.

1 For another perspective, I reviewed the proxy group's current authorized equity
2 ratios to assess whether a 51.50 percent equity ratio would align with the equity
3 ratios authorized for DTE Electric's peers. As shown in Exhibit A-14 Schedule
4 D5.8, a 51.50 percent equity ratio is consistent with the mean and median authorized
5 equity ratios for the proxy companies as shown in Table 11.
6
7 **Table 11 Proxy Group Current Authorized Equity Ratio**
8 **Summary Statistics[71]**

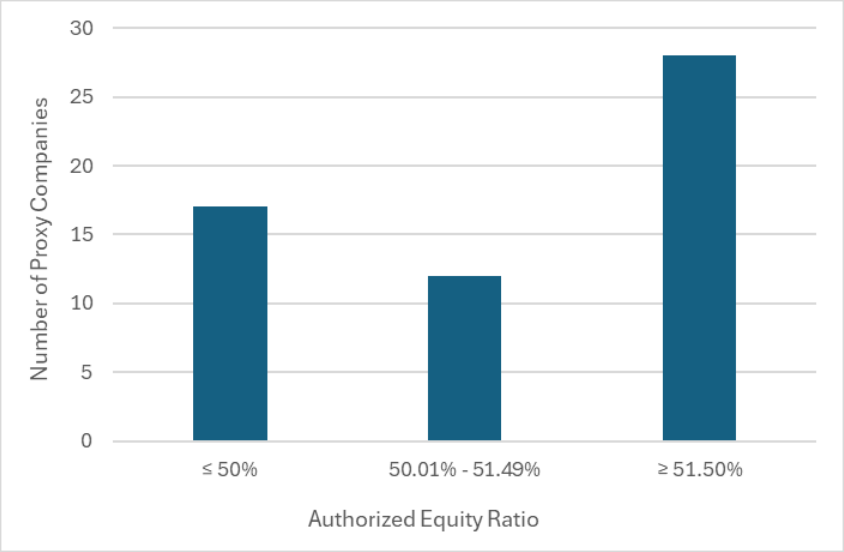
	All Proxy Companies (Distribution & Vertically Integrated)	Only Vertically Integrated Proxy Companies
Low	42.50%	44.00%
High	60.70%	60.70%
Mean	51.56%	51.75%
Median	51.21%	52.04%
Proportion > 50.00%	70.18%	68.09%
Proportion ≥ 51.50%	49.12%	53.19%

9
10 I also evaluated the distribution of authorized equity ratios and confirmed that a 50
11 percent equity ratio is at the low end of the peer group, indicating that the Company
12 has more financial risk than its peers. As Figure 8 shows, only 17 (*i.e.,* 30 percent)
13 proxy companies have an authorized equity ratio of 50 percent or lower, whereas 40
14 (*i.e.,* 70 percent) proxy companies have an equity ratio greater than 50 percent.
15 Further, nearly half have an equity ratio equal to or greater than 51.50 percent.
16 Consequently, the company's requested capital structure is consistent with its peers
17 and is reasonable.

71 See Exhibit A-14, Schedule D5.8. Data source: Regulatory Research Associates.

Line No.

1 **Figure 8. Distribution of Proxy Company Current Authorized Equity Ratios**[72]



2

3

4 **Q77. Is the Company's requested capital structure balanced?**

5 A77. Yes. I understand that the Commission has long expressed a preference for a capital
6 structure that "appropriately balance[s] the interests of the utility's investors and
7 the customers," which it has recently interpreted as a capital structure consisting of
8 equal parts debt and equity.[73] In my opinion, a balanced capital structure considers
9 not only the proportions of debt and equity, but also the Company's risk profile, its
10 financial and credit profile, its unique capital financing needs at a given time,
11 capital market uncertainty, comparability of the capital structure to its peers, and
12 the benefits and costs to customers. At any given time, a particular capital structure
13 that is "balanced" in one market environment may become unbalanced in another.
14 Given its substantial capital investment requirements, and the uncertain economic
15 environment in which it will need to raise capital going forward, it is critical that

72 *See*, Exhibit A-14, Schedule D5.8. Includes both electric distribution proxy companies and vertically integrated electric proxy companies. Data source: Regulatory Research Associates.

73 *See, e.g.*, *In the matter of the application of Consumers Energy Company for authority to increase its rates for the generation and distribution of electricity and for other relief*, Case No. U-21585, Order, March 21, 2025, at 231-232.

Line No.

1 the Company has the financial flexibility to manage its capital structure as the
2 market changes. As discussed below, the Company's risk profile has weakened
3 recently and an increase in the authorized equity ratio will help support its current
4 credit rating and potentially avoid a downgrade that could increase its cost of debt
5 and equity to customers.
6
7 **Q78. Please describe the weakening in DTE Electric's credit profile.**
8 A78. As noted in Section IV, Moody's recently revised DTE Electric's outlook to
9 'Negative,' due to a weakening of the Company's financial metrics driven by its
10 "debt funded expanded capital program."[74] Specifically, Moody's explains:

11 *DTE Electric's negative outlook reflects our expectation that the*
12 *company's elevated investment plan will continue to pressure its credit*
13 *metrics including a [Cash From Operations pre-Working Capital,*
14 *"CFO pre-WC"] to debt ratio below 21%, excluding the impact of*
15 *securitization debt and nuclear decommissioning obligations.*

16 ***

17 *Given the negative outlook, an upgrade is unlikely in the near term. DTE*
18 *Electric's outlook could return to stable if the regulatory environment*
19 *remains supportive and we expect DTE Electric's financial profile to*
20 *improve such that the company's ratio of CFO pre-WC to debt will be*
21 *21% or higher on a sustained basis, when adjusted for securitization*
22 *debt and nuclear decommissioning obligations.*

23 ***

24 *DTE Electric's rating could be downgraded if there is an adverse change*
25 *in Michigan's regulatory environment, leading to more contentiousness*
26 *and a material delay in cost recovery, less transparency, or insufficient*
27 *cost recovery and returns. Also, if DTE Electric's financial metrics*
28 *remain weak including a ratio of CFO pre-WC to debt below 21%,*
29 *excluding the impact of securitization debt and nuclear decommissioning*
30 *obligations, a downgrade could be possible.*[75]

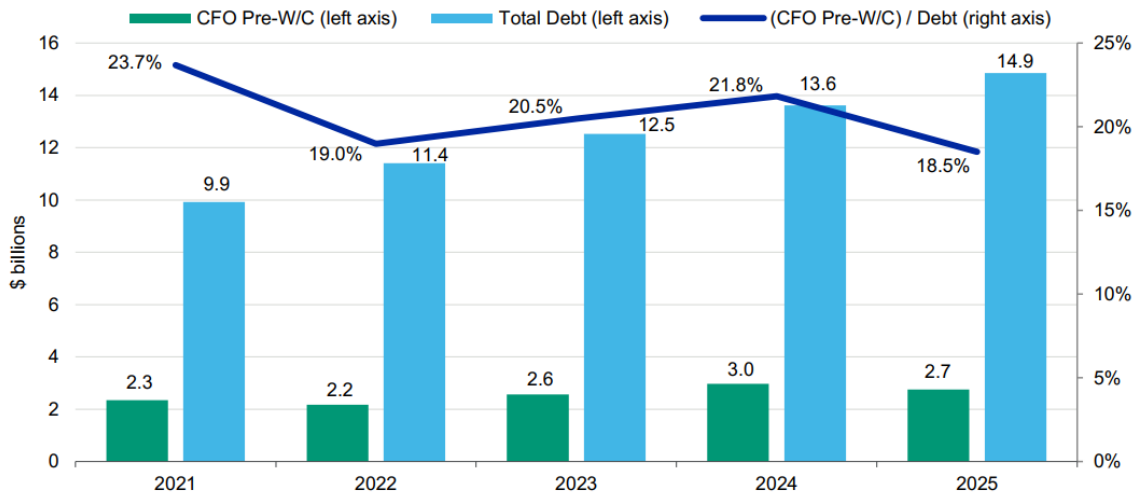
---

74 Moody's Ratings, Credit Opinion, *DTE Electric Company: Update to credit analysis following outlook change to negative*, at 2 (March 31, 2026).

75 *Id*., at 2 [clarification added].

Line No.

1 As shown in Figure 9 below, the weakening in the Company's CFO pre-WC metric
2 is driven primarily by an increase in total debt (light blue bars). A moderate increase
3 in the Company's authorized equity ratio would improve the numerator in its CFO
4 pre-WC metric by increasing cash from operations, as well as potentially stabilize
5 or decrease the debt ratio in the denominator by requiring less debt than DTE
6 Electric would otherwise need to fund its capital expenditures. In short, an increase
7 in DTE Electric's authorized equity ratio would help it maintain its current credit
8 rating from Moody's and potentially avoid a downgrade, as well as signal that the
9 regulatory environment in Michigan remains credit supportive.
10
11 **Figure 9. DTE Electric Historical CFO Pre-WC, Total Debt, and Ratio of CFO**
12 **Pre-WC to Debt (2021-2025)[76]**



All data based on adjusted financial data, which follow our Financial Statement Adjustments in the Analysis of Nonfinancial Corporations methodology.
For analytical purposes, we exclude securitization bonds and the underfunded portion of the Nuclear Decommissioning Trust (NDT) in the credit metric calculations. DTE Electric's CFO pre-W/C to debt ratio in 2023, 2024, and 2025 would be 23.1%, 24.2% and 19.6%, respectively, when we make these adjustments.
Source: Moody's Financial Metrics™

76 *Id.*, at 1.

Line No.

1 **Q79. What is your conclusion regarding DTE Electric's requested capital**
2 **structure?**
3 A79. The Company's requested equity ratio is consistent with sound industry practice
4 and would help support its weakening credit profile. The requested 51.50 percent
5 common equity ratio is in the lower half of the range of the Company's peers (and
6 its debt ratio is in the upper half of its peers) as shown in Exhibit A-14 Schedule
7 D1.1. Further, 70 percent of the proxy companies' current authorized equity ratios
8 are above 50 percent, and approximately 49 percent have an authorized equity ratio
9 equal to or greater than 51.50 percent. Based on the foregoing, the Company's
10 requested capital structure is reasonable, balanced, and should be approved.
11
12 **VI. <u>Capital Market Environment</u>**
13 **Q80. Do economic conditions influence the required cost of capital, including the**
14 **ROE?**
15 A80. Yes. The required cost of capital, including the ROE, is a function of prevailing
16 and expected economic and capital market conditions. Each of the analytical
17 models used to estimate the required ROE is influenced by current and expected
18 capital market conditions. Therefore, an evaluation of current and projected market
19 conditions is integral to any ROE recommendation.
20
21 **Q81. What are the key macroeconomic factors affecting the cost of equity for**
22 **regulated utilities in the current and prospective capital markets?**
23 A81. The cost of equity for regulated utilities is currently affected by several key factors,
24 including: (1) the interest rate environment and central bank monetary policy; (2)
25 inflationary pressure and the longer-term outlook for inflation; and (3) uncertainty

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1 in the economic environment due to geopolitical events. As discussed below,
2 although the Federal Reserve reduced the Federal Funds rate three times in both
3 2024 and 2025, interest rates and inflation are expected to remain above the levels
4 experienced prior to the COVID-19 pandemic. Further, geopolitical events present
5 uncertainties with respect to the near-term economic and capital market in which
6 the Company will be raising external capital.
7
8 **Q82. How have economic and financial market conditions changed in recent**
9 **months?**
10 A82. At the end of 2024, financial markets were optimistic that the Federal Reserve was
11 close to attaining a "soft landing" by taming inflation without a consequential rise
12 in unemployment. In 2025, however, economic and federal policy uncertainty
13 climbed sharply. As *Blue Chip Financial Forecasts* explains, "Numerous Fed
14 officials have noted that there are currently upside risks to the inflation outlook
15 while there are downside risks to the employment outlook, a combination that
16 makes the near-term course for monetary policy very uncertain."[77] Further, in its
17 Outlook 2026 report, J.P. Morgan Private Bank emphasized the structural, rather
18 than temporary, shift in the state of inflation.[78] J.P. Morgan notes that inflation is
19 expected to remain more volatile and prone to upward shocks compared with the
20 pre-pandemic period.[79] Consumer sentiment fell 21 percent between January 2025
21 and February 2026.[80]

---

77 Blue Chip Financial Forecasts, Vol. 44, No. 12, December 1, 2025, at 1.
78 J.P. Morgan Private Bank, *2026 Outlook: Promise and Pressure*, at 7.
79 *Id.*
80 University of Michigan, Survey of Consumers, *Final Results for February 2026*, accessed February 21, 2026, https://www.sca.isr.umich.edu/.

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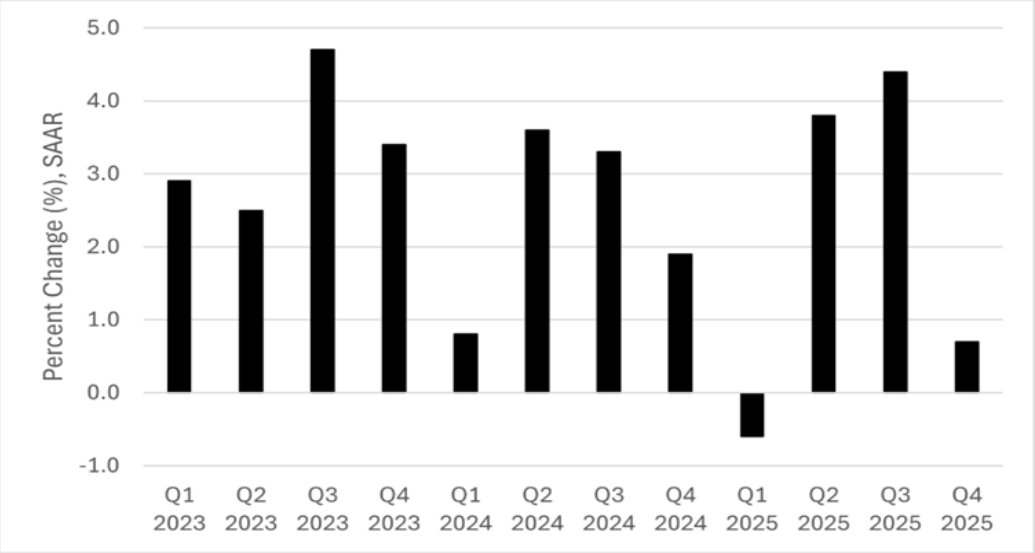
Despite the uncertain economic outlook and weak consumer sentiment, Gross Domestic Product ("GDP") remained resilient, though growth has slowed in the most recent quarter. As shown in Figure 10, after posting a decline in the first quarter of 2025, real GDP rose in each of the next three quarters, though only posted an annual increase of 0.7 percent in the fourth quarter of 2025.[81] This demonstrates that there are mixed signals among the economic indicators.

Figure 10. Quarterly Real GDP (Seasonally Adjusted at Annual Rates)[82]



Q83. Please describe recent monetary policy actions by the Federal Reserve.

A83. At its December 2025 meeting, the Federal Open Market Committee ("FOMC") lowered the target range of the federal funds rate for the third time in 2025 by 25 basis points to 3.50 to 3.75 percent. In doing so, the FOMC noted the downside risks to employment on one hand but that "[i]nflation has moved up since earlier in

81 U.S. Bureau of Economic Analysis, GDP (Second Estimate), 4th Quarter and Year 2025, https://www.bea.gov/sites/default/files/2026-03/gdp4q25-2nd.pdf.

82 Source: U.S. Bureau of Economic Analysis.

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1 the year and remains somewhat elevated."[83] The FOMC maintained its federal
2 funds rate target range at its January and March 2026 meetings, noting that inflation
3 remains "somewhat elevated" and that uncertainty about the economic outlook
4 remains "elevated."[84]
5
6 **Q84. Do the Federal Reserve's recent cuts to the Federal Funds rate mean that long-**
7 **term government and utility bond yields will automatically follow?**
8 A84. Not necessarily. Long-term bond yields – like the 30-year Treasury yield that is
9 applied in the ROE models and used as a benchmark for long-term utility debt –
10 are less sensitive to the Federal Reserve's monetary policy. Long-term interest
11 rates are influenced by the demand and supply for long-term bonds, inflation
12 expectations, fiscal policy, and federal debt levels. As explained in more detail
13 below, consumers' long-term inflation expectations remain elevated and fiscal
14 policy has become more uncertain; thus, long-term government bonds have not
15 declined commensurate with the Federal Reserve's reductions in the Federal Funds
16 rate. As shown in Table 12 below, since the end of June 2024 (prior to the Fed's
17 first round of rate cuts), the 1-year and 2-year Treasury yields declined by 161 and
18 119 basis points, respectively, whereas the 30-year Treasury yields *increased* by 36
19 basis points. Since models used to estimate the just and reasonable ROE rely on
20 long-term yields, the market movement of short-term yields does not influence the
21 ROE model results in the way that long-term yields do.

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83 Federal Reserve FOMC Press Release, December 10, 2025, https://www.federalreserve.gov/newsevents/pressreleases/monetary20251210a.htm.

84 Federal Reserve FOMC Press Release, January 28, 2026, https://www.federalreserve.gov/newsevents/pressreleases/monetary20260128a.htm; Federal Reserve FOMC Press Release, March 18, 2026, https://www.federalreserve.gov/newsevents/pressreleases/monetary20260318a.htm.

Line No.

1 **Table 12 U.S. Treasury Yields (June 2024 vs. January 2026)**[85]

	1-year Treasury	2-year Treasury	30-year Treasury
June 28, 2024	5.09%	4.71%	4.51%
January 30, 2026	3.48%	3.52%	4.87%
Change	-1.61%	-1.19%	+0.36%

2

3 **Q85. Are changes in long-term bond yields more relevant to the cost of equity for**
4 **utilities than short-term interest rates?**

5 A85. Yes. The 30-year Treasury bond yield is a direct input to both the CAPM and Risk
6 Premium models because the term of the bond aligns with the long life of electric
7 utility assets. As long-term bond yields increase, the cost of capital generally
8 increases, and the ROE estimates from those two models also increase, although
9 not on a one-to-one basis. While interest rates are not a direct input to the DCF
10 model, dividend yields on utility stocks must compete with yields on Treasury
11 bonds. As interest rates on government bonds increase, utilities must offer a higher
12 dividend yield to attract and retain investors, signaling an increase in the cost of
13 equity for utilities. All else equal, higher dividend yields produce higher ROE
14 estimates in the DCF model.

15

16 **Q86. What are the expectations for inflation and long-term government and utility**
17 **bond yields in the near term?**

18 A86. Both inflation and long-term government and utility bond yields are expected to
19 remain elevated and significantly above their pre-pandemic levels. As shown in
20 Figures 11 and 12 below, inflation and long-term government and utility bond
21 yields have been higher than the levels experienced in 2019 prior to the COVID-19

85 Source: Federal Reserve Board of Governors, H.15 Selected Interest Rates.

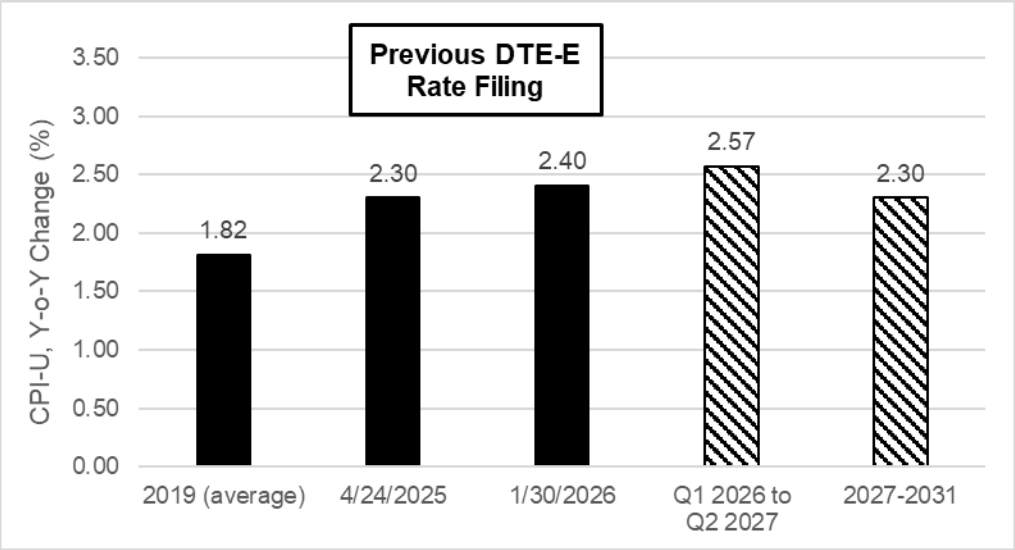
Line No.

1 pandemic and are expected to remain elevated and near current levels over the next

2 five years.

3

4 **Figure 11. Consumer Price Index (2019 vs. 2026 and Forecasted)[86]**



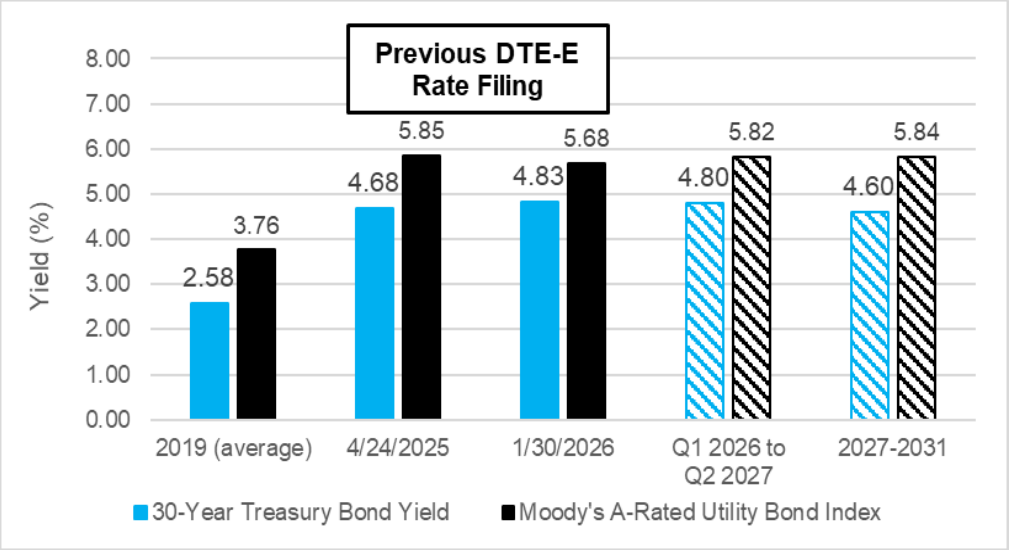
5

86 Sources: Bureau of Labor Statistics, 12-month percentage change, Consumer Price Index, selected categories, not seasonally adjusted, https://www.bls.gov/charts/consumer-price-index/consumer-price-index-by-category-line-chart.htm; Blue Chip Financial Forecasts, Vol. 45 No. 2, at 2 and Blue Chip Financial Forecasts, Vol. 44, No. 12, at 14.

Line No.

1 **Figure 12. 30-Year Treasury Yield and Moody's A Rated Utility Bond Index**

2 **(2019 vs. 2026 and Forecasted)[87]**



3

4 **Q87. How might persistent inflation and elevated interest rates affect the cost of**

5 **equity for utilities?**

6 A87. Longer-term bonds like the 30-year Treasury bond are more sensitive to inflation

7 expectations than shorter-term bonds because their value is influenced more by

8 inflation due to their longer maturity holding period and reinvestment rate

9 implications. Thus, as the value (price) of bonds declines due to higher inflation

10 expectations, the yield increases. Because utilities are capital intensive enterprises,

11 higher inflation and interest rates tend to have a negative effect on utility stocks.

12 Higher inflation and interest rates lead to increases in the cost of capital for utilities.

87 Sources: Federal Reserve Bank of St. Louis, FRED Economic Database, series DGS30, https://fred.stlouisfed.org/series/DGS30; Bloomberg Professional; Federal Reserve Bank of St. Louis, FRED Economic Database, series DAAA, https://fred.stlouisfed.org/series/DAAA; Blue Chip Financial Forecasts, Vol. 45 No. 2, at 2 and Blue Chip Financial Forecasts, Vol. 44 No. 12, at 14. Projected Utility "A" bond yields are estimated from *Blue Chip Financial Forecasts'* projected AAA corporate bond yields plus the average historical spread between AAA-rated corporate and A-rated utility bond yields over the last five years.

Line No.

1 **Q88. Please discuss the recent changes in U.S. trade and geopolitical policy.**

2 A88. During 2025 and 2026, the Trump administration announced, implemented, or
3 delayed implementation of tariffs on numerous U.S. trade partners. A highlight of
4 this is when, on April 2, 2025, President Trump announced the administration
5 would impose a 10 percent base tariff on all imports from nearly every country plus
6 an additional "reciprocal" tariff customized for each of approximately 60
7 countries.[88] These reciprocal tariffs were subsequently paused, but significant
8 uncertainty remains around the future course of U.S. trade policy and how it will
9 affect the economy. More recently, on February 20, 2026, the Supreme Court
10 struck down President Trump's tariffs,[89] though he responded with a pledge to
11 impose a new global 15 percent tariff.[90]

12

13 This created significant policy and market uncertainty; as can be seen in Figure 13
14 below, the Federal Reserve Bank of St. Louis' Economic Policy Uncertainty Index
15 (the "EPU Index") spiked to levels not seen since the COVID-19 pandemic. While
16 the EPU Index has partially subsided in recent months (to 349.75 as of January
17 2026), it is still significantly above the average over the past eleven years (154.02).
18 This heightened U.S. policy and market uncertainty is further evidenced by the
19 weakened U.S. dollar ("USD"), which depreciated against gold and a broad set of
20 foreign currencies in 2025; from December 31, 2024, to December 31, 2025, the
21 USD depreciated 7.80 percent against the Federal Reserve's trade-weighted USD
22 index, and gold prices (as measured in USD) increased by approximately 65

88 https://www.whitehouse.gov/presidential-actions/2025/04/regulating-imports-with-a-reciprocal-tariff-to-rectify-trade-practices-that-contribute-to-large-and-persistent-annual-united-states-goods-trade-deficits/.

89 https://apnews.com/article/supreme-court-tariffs-trump-0485fcda30a7310501123e4931dba3f9.

90 https://www.nytimes.com/2026/02/21/business/trump-tariffs.html.

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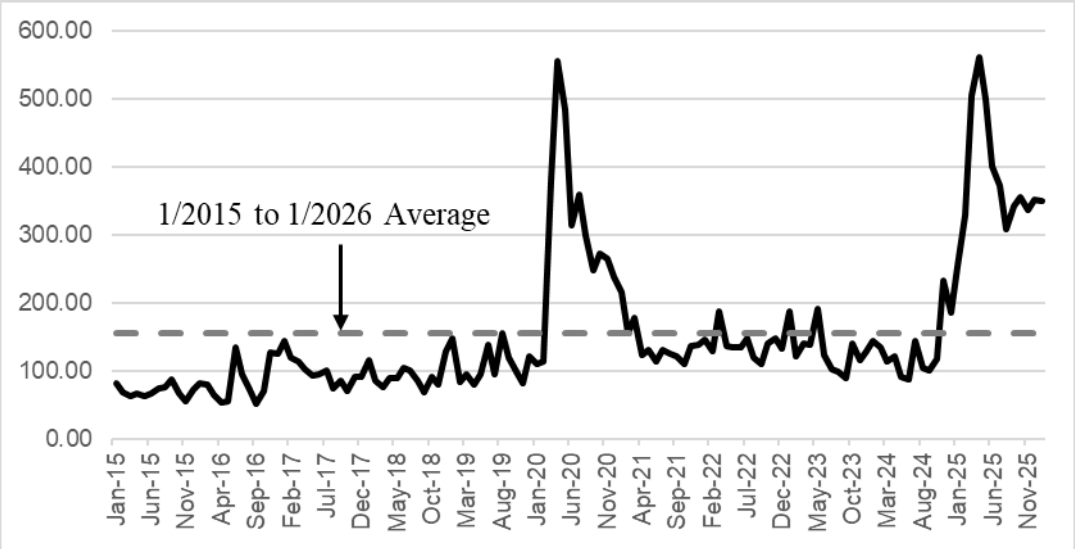
1 percent.[91] The January 3, 2026 U.S. bombing of Venezuela and subsequent capture
2 of Venezuelan President Maduro,[92] potential criminal investigations into Federal
3 Reserve board members, including Chair Powell,[93] and the U.S. and Israeli conflict
4 with Iran[94] further add to the economic and geopolitical uncertainty. Uncertainty
5 increases risk, which increases the cost of equity, all else equal.
6

7 **Figure 13. Economic Policy Uncertainty Index January 1, 2015 – January 31,**
8 **2026[95]**



9
10

11 **Q89. What conclusions do you draw from your review of the current capital market**
12 **environment and its implications for the Company's cost of equity?**

---

91 Sources: Federalreserve.gov H10 data; Goldprice.org.

92 https://www.cbsnews.com/live-updates/venezuela-us-military-strikes-maduro-trump/.

93 https://abcnews.go.com/Politics/doj-launches-criminal-investigation-fed-chair-jerome-powell/story?id=129114228https://abcnews.go.com/Politics/doj-launches-criminal-investigation-fed-chair-jerome-powell/story?id=129114228.

94 https://www.pbs.org/newshour/world/u-s-and-israel-launch-a-major-attack-on-iran-trump-says-supreme-leader-khamenei-killed.

95 Source: Federal Reserve Bank of St. Louis, FRED Economic Database, series USEPUINDXD, https://fred.stlouisfed.org/series/USEPUINDXD/.

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1 A89. My primary conclusion is that the economic and financial market environment is
2 uncertain concerning inflation, the strength of the economy, the outcome of federal
3 trade policy and other geopolitical events, and the path of monetary policy.
4 Although the Federal Reserve cut the level of short-term interest rates in 2025,
5 long-term government and utility bond yields have not followed suit and remain
6 elevated relative to the very low-interest rate environment experienced in the prior
7 decade. Lastly, inflation is expected to remain elevated and above pre-pandemic
8 levels. These factors underscore the importance of using multiple models when
9 determining the Company's cost of equity to gain a comprehensive perspective of
10 the effect of fluid and evolving market conditions on the cost of equity.
11
12 **VII. <u>Conclusions and Recommendation</u>**
13 **Q90. What is your conclusion regarding the ROE and capital structure for DTE**
14 **Electric?**
15 A90. As discussed throughout my Direct Testimony, it is important to consider a variety
16 of quantitative and qualitative information in reviewing analytical results and
17 arriving at ROE determinations. Based on my review of the results from three
18 commonly used analytical approaches, I conclude an ROE in the range of 9.95
19 percent to 11.80 percent represents the range of equity investors' required return on
20 investment in electric utilities that are comparable to DTE Electric in today's capital
21 market environment, which would support an ROE of 10.85 percent, representing
22 the approximate midpoint of the range. The Company's requested ROE of 10.25
23 percent is a reasonable and conservative estimate of DTE Electric's cost of equity,
24 designed to ensure gradualism in terms of the impact on customer rates.

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As to capital structure, the Company's requested permanent capital structure of 51.50 percent common equity and 48.50 percent long-term debt is within the range of capital structures that finance the regulated electric utility operations of the proxy group and, therefore, is reasonable and appropriate and should be approved.

Q91. Does this conclude your Direct Testimony?

A91. Yes, it does.

Proxy Group Regulatory Risk Comparative Assessment

				Adjustment Clauses							Ratemaking Framework Component		
Company	Parent	Jurisdiction	Service	Fuel/ Purchased Power	Volumetric Risk Mitigation [1]	New Capital Investment [2]	Energy Efficiency [3]	Renewables & RPS [4]	Environmental [5]	Other [6]	Jurisdiction Test Year	Jurisdiction Rate Base Methodology	RRA Commission Ranking [7]
Ameren Illinois Company	AEE	Illinois	Electric	✓	✓	✓	✓	✓	✓	✓	Forecast Permitted	Year End	Average / 3
Union Electric Company	AEE	Missouri	Electric	✓	✓	✓	✓	✓	✓	✓	Partially Forecast	Year End	Average / 2
Southwestern Electric Power Company	AEP	Arkansas	Electric	✓	✓	✓	✓		✓	✓	Forecast Permitted	Year End	Average / 1
Indiana Michigan Power Company	AEP	Indiana	Electric	✓	✓	✓	✓	✓	✓	✓	Forecast Permitted	Year End	Average / 1
Kentucky Power Company	AEP	Kentucky	Electric	✓	✓	✓	✓	✓	✓	✓	Historical	Year End	Average / 2
Southwestern Electric Power Company	AEP	Louisiana	Electric	✓	✓	✓	✓	✓	✓	✓	Historical	Average	Average / 2
Indiana Michigan Power Company	AEP	Michigan	Electric	✓	✓		✓	✓	✓	✓	Fully Forecast	Average	Average / 1
Ohio Power Company	AEP	Ohio	Electric	✓	✓	✓	✓	✓		✓	Partially Forecast	Year End	Average / 1
Public Service Company of Oklahoma	AEP	Oklahoma	Electric	✓	✓	✓	✓	✓		✓	Historical	Year End	Average / 3
Kingsport Power Company	AEP	Tennessee	Electric	✓		✓				✓	Fully Forecast	Average	Above Average / 3
AEP Texas Inc.	AEP	Texas	Electric	NA		✓	✓		✓	✓	Historical	Year End	Below Average / 1
Southwestern Electric Power Company	AEP	Texas	Electric	✓		✓	✓	✓		✓	Historical	Year End	Below Average / 1
Appalachian Power Company	AEP	Virginia	Electric	✓		✓	✓	✓	✓	✓	Forecast Permitted	Average	Average / 1
Appalachian Power / Wheeling Power	AEP	West Virginia	Electric	✓		✓	✓	✓	✓	✓	Historical	Average	Below Average / 1
Alaska Electric Light and Power Company	AVA	Alaska	Electric	✓						✓	Historical	Average	Below Average / 1
Avista Corporation	AVA	Idaho	Electric	✓	✓		✓			✓	Historical	Average	Average / 2
Avista Corporation	AVA	Washington	Electric	✓	✓	✓	✓	✓		✓	Forecast Permitted	Average	Average / 3
Consumers Energy Company	CMS	Michigan	Electric	✓			✓	✓		✓	Fully Forecast	Average	Average / 1
Dominion Energy South Carolina	D	South Carolina	Electric	✓			✓	✓	✓	✓	Historical	Year End	Average / 2
Dominion Energy North Carolina	D	North Carolina	Electric	✓	✓		✓	✓	✓	✓	Historical	Year End	Above Average / 3
Virginia Electric and Power Company	D	Virginia	Electric	✓		✓	✓	✓	✓	✓	Forecast Permitted	Average	Average / 1
Duke Energy Florida, LLC	DUK	Florida	Electric	✓		✓	✓	✓	✓	✓	Partially Forecast	Average	Above Average / 2
Duke Energy Indiana, LLC	DUK	Indiana	Electric	✓	✓	✓	✓	✓	✓	✓	Forecast Permitted	Year End	Average / 1
Duke Energy Kentucky, Inc.	DUK	Kentucky	Electric	✓	✓		✓		✓	✓	Historical	Year End	Average / 2
Duke Energy Carolinas, LLC	DUK	North Carolina	Electric	✓	✓		✓	✓	✓	✓	Historical	Year End	Above Average / 3
Duke Energy Progress, LLC	DUK	North Carolina	Electric	✓	✓	✓	✓	✓	✓	✓	Historical	Year End	Above Average / 3
Duke Energy Ohio, Inc.	DUK	Ohio	Electric	✓	✓	✓	✓	✓		✓	Partially Forecast	Year End	Average / 1
Duke Energy Carolinas, LLC	DUK	South Carolina	Electric	✓	✓		✓	✓	✓	✓	Historical	Year End	Average / 2
Duke Energy Progress, LLC	DUK	South Carolina	Electric	✓	✓		✓	✓	✓	✓	Historical	Year End	Average / 2
Entergy Arkansas, LLC	ETR	Arkansas	Electric	✓	✓	✓	✓		✓	✓	Forecast Permitted	Year End	Average / 1
Entergy Louisiana, LLC	ETR	Louisiana	Electric	✓	✓	✓	✓		✓	✓	Historical	Average	Average / 2
Entergy Mississippi, LLC	ETR	Mississippi	Electric	✓	✓	✓				✓	Forecast Permitted	Average	Above Average / 3
Entergy New Orleans, LLC	ETR	Louisiana - NOCC	Electric	✓	✓	✓	✓		✓	✓	Forecast Permitted	Average	Average / 3
Entergy Texas, Inc.	ETR	Texas	Electric	✓		✓	✓			✓	Historical	Year End	Below Average / 1
Evergy Kansas Central	EVRG	Kansas	Electric	✓	✓		✓		✓	✓	Historical	Year End	Average / 3
Evergy Kansas Metro	EVRG	Kansas	Electric	✓			✓		✓	✓	Historical	Year End	Average / 3
Evergy Missouri Metro	EVRG	Missouri	Electric	✓	✓	✓	✓		✓	✓	Partially Forecast	Year End	Average / 2
Evergy Missouri West	EVRG	Missouri	Electric	✓	✓	✓	✓	✓	✓	✓	Partially Forecast	Year End	Average / 2
Cleveland Electric Illuminating Company	FE	Ohio	Electric	✓		✓	✓	✓		✓	Partially Forecast	Year End	Average / 1
Jersey Central Power & Light Company	FE	New Jersey	Electric	✓	✓	✓	✓	✓	✓	✓	Partially Forecast	Year End	Average / 3
Ohio Edison Company	FE	Ohio	Electric	✓		✓	✓	✓		✓	Partially Forecast	Year End	Average / 1
FirstEnergy Pennsylvania Electric Co.	FE	Pennsylvania	Electric	✓		✓	✓			✓	Fully Forecast	Year End	Above Average / 2
Monongahela Power Company	FE	West Virginia	Electric	✓				✓	✓	✓	Historical	Average	Below Average / 1
Potomac Edison Company	FE	Maryland	Electric	✓			✓	✓	✓	✓	Forecast Permitted	Average	Below Average / 3
Potomac Edison Company	FE	West Virginia	Electric	✓				✓	✓	✓	Historical	Year End	Below Average / 1
Toledo Edison Company	FE	Ohio	Electric	✓		✓	✓	✓		✓	Partially Forecast	Year End	Average / 1
Idaho Power Co.	IDA	Idaho	Electric	✓	✓		✓			✓	Historical	Average	Average / 2
Idaho Power Co.	IDA	Oregon	Electric	✓			✓	✓		✓	Partially Forecast	Average	Average / 3
Interstate Power and Light Company	LNT	Iowa	Electric	✓		✓	✓	✓	✓	✓	Historical	Year End	Above Average / 3
Wisconsin Power and Light Company	LNT	Wisconsin	Electric	✓						✓	Fully Forecast	Average	Above Average / 3
Florida Power & Light Company	NEE	Florida	Electric	✓		✓	✓	✓	✓	✓	Partially Forecast	Average	Above Average / 2
Oklahoma Gas and Electric Company	OGE	Arkansas	Electric	✓	✓	✓	✓		✓	✓	Forecast Permitted	Year End	Average / 1
Oklahoma Gas and Electric Company	OGE	Oklahoma	Electric	✓	✓	✓	✓			✓	Historical	Year End	Average / 3
Arizona Public Service Company	PNW	Arizona	Electric	✓	✓	✓	✓	✓	✓	✓	Historical	Year End	Below Average / 2

Company	Parent	Jurisdiction	Service	Fuel/ Purchased Power	Volumetric Risk Mitigation [1]	New Capital Investment [2]	Energy Efficiency [3]	Renewables & RPS [4]	Environmental [5]	Other [6]	Jurisdiction Test Year	Jurisdiction Rate Base Methodology	RRA Commission Ranking [7]
Portland General Electric Company	POR	Oregon	Electric	✓	✓	✓	✓	✓	✓	✓	Partially Forecast	Average	Average / 3
Kentucky Utilities Company	PPL	Kentucky	Electric	✓	✓		✓		✓	✓	Historical	Year End	Average / 2
Old Dominion Power Company	PPL	Virginia	Electric	✓							Forecast Permitted	Average	Average / 1
Louisville Gas and Electric Company	PPL	Kentucky	Electric	✓	✓		✓		✓	✓	Historical	Year End	Average / 2
PPL Electric Utilities Corporation	PPL	Pennsylvania	Electric	✓		✓	✓			✓	Fully Forecast	Year End	Above Average / 2
Rhode Island Energy	PPL	Rhode Island	Electric	✓	✓	✓	✓	✓		✓	Historical	Average	Average / 2
Alabama Power Company	SO	Alabama	Electric	✓	✓	✓			✓	✓	Historical	Year End	Above Average / 1
Georgia Power Company	SO	Georgia	Electric	✓		✓	✓		✓	✓	Fully Forecast	Average	Above Average / 2
Mississippi Power Company	SO	Mississippi	Electric	✓	✓	✓		✓	✓	✓	Forecast Permitted	Average	Above Average / 3
Public Service Company of Colorado	XEL	Colorado	Electric	✓	✓	✓	✓	✓	✓	✓	Historical	Average	Average / 1
Northern States Power Company - WI	XEL	Michigan	Electric	✓				✓		✓	Fully Forecast	Average	Average / 1
Northern States Power Company - MN	XEL	Minnesota	Electric	✓	✓	✓	✓	✓	✓	✓	Fully Forecast	Average	Average / 2
Southwestern Public Service Company	XEL	New Mexico	Electric	✓		✓	✓	✓		✓	Forecast Permitted	Average	Below Average / 1
Northern States Power Company - MN	XEL	North Dakota	Electric	✓		✓		✓		✓	Partially Forecast	Average	Average / 1
Northern States Power Company - MN	XEL	South Dakota	Electric	✓	✓	✓	✓		✓	✓	Historical	Average	Average / 2
Southwestern Public Service Company	XEL	Texas	Electric	✓		✓	✓			✓	Historical	Year End	Below Average / 1
Northern States Power Company - WI	XEL	Wisconsin	Electric	✓						✓	Fully Forecast	Average	Above Average / 3
		% of Proxy Group		100%	56%	68%	83%	61%	62%	99%	55%	45%	46%
											% Partial or Fully Forecast	*% Average Rate Base Methodology*	*% jurisdictions rated equal to or better than Average / 1*
DTE Electric Company	DTE	Michigan	Electric	✓		✓	✓	✓	✓	✓	Fully Forecast	Average	Average / 1

Notes:

A mechanism may cover one or more cost categories; therefore, designations may not indicate separate mechanisms for each category. Texas T&D electric utilities do not have retail obligation, thus do not need a fuel or purchased power cost recovery mechanism.

[1] Volumetric Risk Mitigation mechanisms include full or partial decoupling, straight fixed variable rate design, weather normalization adjustment clauses, recovery of lost revenues as a result of Energy Efficiency programs, and earnings true-up mechanisms, such as formula rate plans or annual rate review riders.

[2] Includes recovery of capital investment related to new generation projects, transmission capital, infrastructure replacement, system integrity/hardening, Smart Grid, AMI metering, and other capital expenditures.

[3] Utility-sponsored conservation, energy efficiency, load control, or other demand side management programs.

[4] Recovers costs associated with renewable energy projects, distributed energy resources, REC purchases, net metering, RPS expense, and renewable PPAs.

[5] EPA upgrade costs, emissions control & allowance purchase costs, nuclear/coal plant decommissioning, and other costs to comply with state and federal environmental mandates.

[6] Cost recovery for items such as pension expenses, bad debt expense, low income programs, storm costs, vegetation management, RTO/transmission expense (not capital), government & franchise fees and taxes, and regulatory fees.

[7] RRA maintains three principal rating categories, Above Average, Average, and Below Average, with Above Average indicating a relatively more constructive, lower-risk regulatory environment from an investor viewpoint, and Below Average indicating a less constructive, higher-risk regulatory climate from an investor viewpoint. Within the three principal rating categories, the numbers 1, 2, and 3 indicate relative position. The designation 1 indicates a stronger (more constructive) rating; 2, a mid range rating; and, 3, a weaker (less constructive) rating. We endeavor to maintain an approximately equal number of ratings above the average and below the average.

Sources: Regulatory Research Associates, Adjustment Clauses: A State-by-State Overview, September 22, 2025; Regulatory Research Associates Quarterly State Regulatory Evaluations - July 2025; RRA - Commission Profiles; SEC Form 10-Ks; Company tariffs.

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-22046
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS

AND

REVISED DIRECT TESTIMONY

OF

JOSEPH E. ROBINSON

DTE ELECTRIC COMPANY
QUALIFICATIONS AND REVISED DIRECT TESTIMONY OF JOSEPH E. ROBINSON

Line No.

I. Background & Qualifications

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

A1. My name is Joseph E. Robinson. My business address is One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Electric ("DTE Electric" or the "Company").

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of DTE Electric.

Q3. Please state your educational background.

A3. I hold a Bachelor of Science in Electrical Engineering and a Master of Science in Electrical Engineering, both from Michigan Technological University.

Q4. Please summarize your work experience.

A4. Since joining DTE Electric in 1993 as an electrical engineer, I have advanced through a variety of roles in engineering, operations, and regulatory compliance. My early career focused on technical disciplines, including industrial control system design, process control strategy development, and plant performance optimization. Building on this foundation, I transitioned into leadership positions where I directed initiatives to improve reliability and ensure compliance, such as implementing an advanced vegetation management program and overseeing comprehensive NERC compliance activities. In recent years, I have led teams responsible for system operations, central engineering functions, and regulatory audit responses, including Case No. U-21305.

Line No.

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

2 **A5.** As Director of DO Asset & Work Management, I lead the team that is responsible for
3 the power delivery asset lifecycle health and condition monitoring to obtain greater
4 asset performance and electric grid reliability.

5

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

8 **A6.** Yes. I have sponsored testimony in the following cases:

9 U-17767 2014 DTE Electric Rate Case
10 U-20836 2022 DTE Electric Rate Case
11 U-21193 2023 DTE Electric Integrated Resource Plan
12 U-21297 2023 DTE Electric Rate Case
13 U-21860 2025 DTE Electric Rate Case

Line No.

II. Overview & Executive Summary

Q7. What is the purpose of your testimony in this proceeding?

A7. The purpose of my testimony is to support, as reasonable, prudent, and necessary, expenditures for the distribution strategic capital category of the Resilience and Hardening pillar, as well as Preventative Maintenance and Corrective Maintenance. This testimony supports the following expenditure periods:

1) the historical test period for both the capital and Operations and Maintenance (O&M) expenditures for 2025,
2) the projected capital and O&M expenditures for the 14-month bridge period ("Bridge Period") between January 1, 2026, through February 28, 2027, and
3) the projected capital and O&M expenditures for the projected test year ("Projected Test Year") which runs from March 1, 2027 through February 29, 2028.

Q8. How is your testimony organized?

A8. Following the introductory material above and the executive summary material below, my testimony is organized by programs and projects within the Resilience & Hardening pillar as follows:

III. 4.8kV Hardening Program
IV. Small Wire Replacement Program
V. Pole and Pole-Top Maintenance and Modernization Program ("PTMM")
VI. Frequent Outage Programs ("Customers Experiencing Multiple Interruptions", "CEMI")
VII. Restoration Readiness and Community Resilience

Line No.

A. Mobile Fleet Program

VIII. Pilot: Strategic and Service Undergrounding

IX. Substation Risk Projects

A. Flood-related Substation Risk Projects

B. Failed Equipment-Related Substation Risk Projects

X. System Equipment Replacement Program

A. Substation Equipment Investments

B. Overhead Equipment Investments

C. Underground System Investments

D. Station Upgrade Projects

XI. Preventative Maintenance ("PM") Program

XII. Corrective Maintenance ("CM") Program

Q9. Are you sponsoring any exhibits in this proceeding?

A9. Yes. I am supporting the following exhibits:

Exhibit	Schedule	Description
A-12	B5.4 Revised	Projected Capital Expenditures – Distribution Plant (Pages 1-3, 9, 16-23)
A-12	B5.4.8	Electric Rate Case (ERC) and Infrastructure Recovery Mechanism (IRM) Revenue Recovery Partition
A-13	C5.6 Revised	Projected Operation and Maintenance Expenses – Distribution Expenses (Pages 1-2)
A-23	M3	Distribution Plant Capital Project Detail –Resilience and Hardening
A-23	M9	Wood Pole Maintenance Specification

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A-23	M10	Pole-Top Maintenance Specification
A-23	M11	PTMM Audit Recommendation Analysis
A-23	M12	PTMM Industry Standards Summary
A-23	M13	4.8kV Hardening Program Alternative Analysis

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

A10. Yes, they were.

Q11. Can you explain the focus and goals of the Company's Resilience and Hardening pillar?

A11. The Resilience and Hardening pillar, as introduced by Witness Chiu, includes programs and projects focused on near-term grid infrastructure investments that harden the system against an increasing frequency and severity of high winds and storms,[1] address frequent outage circuits, and replace damaged and/or defective infrastructure, or equipment that is beyond useful life expectancy, determined by asset health assessments, as I discuss later in my testimony. Additionally, investments in this pillar are essential to maintain the Company's electric distribution system and meet customer expectations for safety, reliability, power capacity, and quality.

Q12. What investment are you supporting with this testimony in the instant case?

A12. My testimony supports both capital and O&M costs related to the Resilience and Hardening pillar and base capital for the Corrective Maintenance program. My testimony also supports O&M for Preventative Maintenance. Resilience and Hardening pillar capital investments include, approximately $315.7 million in the 2025 historical

[1] See the discussion by Witness Chiu on the severity of recent storm impacts to a grid that is in need of significant system hardening.

Line No.

1 test year, approximately $230.8 million within the 14-month bridge period between
2 January 1, 2026, through February 28, 2027, and approximately $276.9 million in the
3 projected test year spanning from March 1, 2027, to February 29, 2028.[2]
4 Base capital for Corrective Maintenance is approximately $34.8M for the projected test
5 year. The O&M projected adjustments supported through this testimony is
6 approximately $9.1 million in the bridge and projected test year (spanning from March
7 1, 2027 to February 29, 2028).[3]
8
9 **Q13. What O&M costs are you sponsoring?**
10 **A13.** I sponsor the Pole-Top Maintenance inspections, both pole and pole-top inspections,
11 infrared thermography, as well as the Preventative Maintenance (PM) program and
12 Corrective Maintenance (CM), with the Corrective Maintenance category split between
13 capital and O&M. Additionally, I sponsor system cable testing within the system cable
14 program.
15
16 **Q14. How does the Resilience and Hardening pillar relate to the Company's**
17 **Distribution Operations Business Unit's investment strategy?**
18 **A14.** As Witnesses Chiu and Kryscynski explain in their direct testimonies, the Company's
19 Distribution Operations Business Unit ("Distribution Operations") has identified near-
20 term and longer-term initiatives to improve near-term reliability and develop a roadmap
21 to sustain long-term reliability improvements and modernize the grid. These
22 investments are organized within the Reliability and Modernization Investment
23 Framework, which is comprised of five key pillars, including the Resilience and
24 Hardening pillar.

[2] U-22046 Ex. A-12, Sch. B5.4 Revised, p 1
[3] U-22046 Ex. A-13, Sch. C5.6 Revised, p. 2

Line No.

The Resilience and Hardening pillar is comprised of programs and projects designed to improve the foundation of DTE Electric's distribution system and make it safer and more reliable and resilient.

In that regard, it focuses investments on equipment replacement for equipment that fails inspection, is defective and prone to premature failure, is at or nearing the end of its useful life, or is obsolete, meaning there is limited availability of spare replacement parts. Replacing failed, failing, and obsolete equipment is essential for maintaining and improving the Company's distribution service.

Q15. What is new or different with respect to the Resilience and Hardening pillar since the Company filed its previous electric rate case, Case No. U-21860?

A15. A new organizational category, Restoration Readiness and Community Resilience, has been established to further structure projects within the Company's Resilience and Hardening pillar. While the naming, formal designation, and consolidation of this category are new, the underlying work and program included within it—such as the mobile fleet program—is not new and has been an ongoing Company initiative. The purpose of this category is to organize and present the Company's investments that are intended to remediate failures that have already occurred and to mitigate the risk of catastrophic failures in the future.

The Company has reclassified the Strategic Undergrounding program from the Redesign & Modernization Pillar to the Resilience and Hardening Pillar and renamed the program Strategic and Service Undergrounding. This reclassification more accurately reflects the program's primary purpose. The Strategic and Service

Line No.

1 Undergrounding program is designed to enhance system resiliency and improve
2 reliability by reducing outage risk associated with overhead infrastructure. In contrast,
3 the Redesign & Modernization Pillar is focused on addressing capacity-driven system
4 needs. Accordingly, the reclassification aligns the program more directly with the
5 objectives of the Resilience and Hardening Pillar.
6
7 **III. <u>4.8kV Hardening Program</u>**
8 **Q16. Can you explain the purpose and scope of the 4.8kV Hardening Program?**
9 **A16.** The 4.8kV Hardening Program's goals are to enhance public and employee safety,
10 improve customer reliability, and reduce grid risk by increasing the Company's grid
11 resiliency. This program supports safety by removing Detroit Public Lighting
12 Department ("DPLD") arc wire that is co-located with DTE Electric equipment and at
13 risk of becoming energized. Two features specific to the City of Detroit distribution
14 infrastructure dictate the scope of the Program: (1) the existence of DPLD arc wire
15 owned by the City of Detroit and (2) the co-location of the DPLD arc wire with
16 Company infrastructure. Accordingly, the Program does not address DPLD arc wire
17 that is not co-located with the Company's existing infrastructure, as it does not pose
18 the same safety risk when it is not co-located with the Company's existing
19 infrastructure. More specifically, the Program focuses on the co-located DPLD arc
20 wire because it may present a safety risk due to its close proximity to energized wire
21 and its potential for energization. Further, while the Program does not target areas that
22 do not contain DPLD arc wire, there are instances where a circuit contains some arc
23 wire, but that arc wire is not along the entirety of the circuit. In those instances, the
24 Program will harden the entire circuit to optimize program investment, as there is
25 inherent cost to plan work and mobilize crews and there are resulting benefits to all

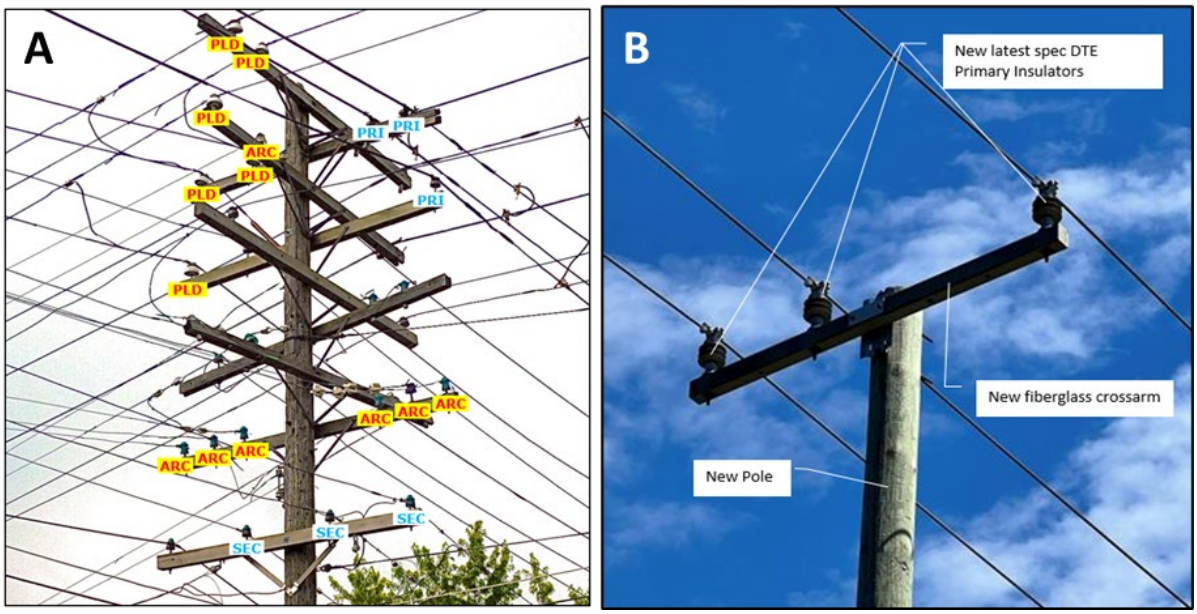
Line No.

1 customers in the area in terms of improved safety and reliability. In summary, the
2 Program enhances grid safety by removing DPLD arc wire that is co-located with DTE
3 Electric equipment and is at risk of becoming energized, as well as improves reliability
4 by replacing damaged poles and pole-top equipment in areas with some of the oldest
5 infrastructure in DTE Electric's service territory.
6
7 The Company implemented the Program beginning in 2018 to address all overhead
8 circuits in and around the city of Detroit in areas known to contain DPLD arc wire.
9 The Program's work activities include:
10 • Inspecting all utility poles that have Company equipment attached and replace
11 or reinforce those poles as needed;
12 • Trimming trees, as required, to support construction activities;
13 • Removing DPLD arc wire from Company-owned equipment and leaving
14 Company wires in a safe configuration;
15 • Removing DPLD distribution wire from Company-owned equipment when it
16 can be confirmed that the wire is not serving customers;
17 • Replacing wooden crossarms with fiberglass crossarms as needed;
18 • Replacing other pole-top equipment as required, allowing for rebalancing of the
19 remaining conductor;
20 • Removing service lines to abandoned properties; and
21 • Performing any additional work necessary as dictated by field conditions.
22
23 Upon completion of the 4.8kV Hardening Program's work activities, the Company will
24 have inspected almost every pole on the selected circuits, and the poles will have new

Line No.

cross arms and pole-top equipment where needed, as shown in Figure 1 below. As a result, the distribution infrastructure will be safer and more reliable.

Figure 1. (A) Before Hardening and (B) After Hardening



Shown above is an example of a pole (A) before hardening and a pole (B) after hardening. Note the terms above: PLD - DPLD Distribution Wire; ARC - DPLD Arc Wire; PRI - DTE Electric Primary Wire; and SEC - DTE Electric Secondary Wire

Q17. Has the 4.8kV Hardening Program always included tree trimming and pole and pole-top equipment replacement in addition to the removal of DPLD arc wire?

A17. Yes, as the Company explained in Case Nos. U-21534 and U-21860, these activities are necessary for worksite accessibility and improved safety. Specifically, tree trimming is necessary for field crews to access the poles and wires to perform the work activities, and testing and replacing or reinforcing poles is necessary to improve safety for the field crews and the public, as well as to support improved resiliency and reliability. The replacement or reinforcement of poles enhances safety by making the infrastructure more resilient to weather and other external factors, such as tree

Line No.

interference and vehicle accidents. This pole focused work also reduces the risk of poles breaking and/or downed wires, thereby improving protection for both the public and crews from potential electrical hazards.

Q18. How does the 4.8kV Hardening Program benefit customers?

A18. This program was found by the Audit Report to be "sound" and to have improved "resiliency and safety." Specifically, the hardening program has reduced the number of outages and the duration of outages our customers have experienced. In addition, it has reduced wire down events.

Q19. Are there additional benefits in the overall 4.8 kV Hardening Program beyond the reliability benefits of tree trimming?

A19. Yes, as I explain below, the Commission found in Case No. U-21534 that "DTE Electric demonstrated the benefits that are accruing to customers as a result of both hardening and wire removal" and that the Company did not need to "show that the improved reliability metrics are solely due to the hardening effort in order to find value in this work."[4] These benefits include enhanced public safety by reducing wire downs, as well as improving reliability by reducing both the number of outages and the duration of outages.

[4] Case No. U-21534 Commission Order dated January 23, 2025, p. 104

Line No.

1 **Q20. How has the Commission responded to the Company's prior investments in the**
2 **4.8kV Hardening Program, including DTE Electric's associated work activities**
3 **you described?**
4 **A20.** The Commission approved the Company's 4.8kV Hardening Program investments in
5 Case Nos. U-20162, U-20561, U-20836, U-21297, U-21534, and U-21860. Further, the
6 4.8kV Hardening Program aligns with the Commission's expectation that the Company
7 remove DPLD arc wire.[5]
8 The Commission reiterated its support for the Company's 4.8kV Hardening Program
9 in Case No. U-21534 stating:
10 Beyond the primary safety issue, DTE Electric demonstrated the
11 benefits that are accruing to customers as a result of both hardening and
12 wire removal. For example, all-weather SAIFI and SAIDI excluding
13 MEDs have both improved in the wake of the hardening effort, as have
14 wire downs. While not a formal BCA, the Commission is satisfied with
15 the level of quantification reflected in the company's evidence.
16 Moreover, the Commission does not find that the company needs to
17 show that the improved reliability metrics are solely due to the
18 hardening effort in order to find value in this work. This program was
19 never expected to eliminate the risk of all downed wires, but it is clearly
20 addressing the risk associated with downed arc wire. The company has
21 also shown that the benefits of the hardening and tree trimming will not
22 necessarily be lost when the conversion to 13.2kV takes place (such as
23 retention of the crossarms); the program is not redundant with PTMM;

[5] In its September 28, 2018, Order in Case No. U-18484 the Commission noted that "[a]ppropriate integration of arc wire removal with other DTE Electric programs, such as the hardening and conversion programs, is a crucial aspect of planning and executing strategies." (U-18484 Order, p. 6.)

Line No.

and it doubles the number of circuit miles addressed for tree trimming, pole top inspection and replacement, and pole inspection and replacement. For all of these reasons, the Commission approves the capital expenditures reported and projected by DTE Electric.[6]

Q21. Did the Liberty Consulting Group's document titled Final Report Utility Distribution Audit of DTE Energy ("Audit Report") in Case No. U-21305 include any conclusions related to the 4.8kV Hardening Program?

A21. Yes, the Audit Report did include a conclusion specific to the DTE Electric 4.8kV Hardening Program, recognizing that "[c]ompletion of the City of Detroit 4.8kV hardening program as the DGP plans is sound."[7] Further, the Audit Report stated, "[t]his program, which continues the removal of arc wire that formed an integral part of its institution, is nearing completion. It has improved resiliency and safety."[8]

Q22. What is the status of the Company's efforts to remove the DPLD arc wire as part of the 4.8kV Hardening Program?

A22. As outlined in Table 1 below, the Company hardened a total of approximately 1,119 miles and removed a total of approximately 435 miles of arc wire between 2018 and 2022.

[6] U-21534 Commission Order, January 23, 2025, p. 104
[7] Case No. U-21305, 068cs00000AyaNpAAJ, Audit Report, Part Two, Chapter 2, p. 75.
[8] Ibid, pg. 75.

Line No.

1 **Table 1 - 4.8kV Miles Hardened and Arc Wire Removed (2018-2022)**

4.8kV Hardening	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	Total
Miles Hardened	105	128	209	202	475	**1,119**
Arc Wire Miles	59	52	105	64	155	**435**
Capital Investment ($ millions)	$40.3	$48.3	$55.25	$65.4	$157.5	

2

3 As outlined in Table 2 below, the Company subsequently hardened approximately 762
4 miles from 2023 through 2025. In that same time frame, a total of 438 miles of arc wire
5 was removed. In 2026 and 2027, the Company estimates an additional 313 miles will
6 be hardened and an additional 187 miles of arc wire will be removed.

7

8 **Table 2 - 4.8kV Miles Hardened and Arc Wire Removed (2023-2027)** [9]

4.8kV Hardening	2023 Actuals	2024 Actuals	2025 Actuals	2026 Forecast	2027 Forecast	Total
Miles Hardened	373	164	225	175	138	1,075
Arc Wire Miles	208	24	206	105	82	625
Capital Investment ($ millions)	$130.5	$92.3	$126.1	$82.0	$61.4	

[9] Arc miles are included in the year the circuit is completed. Arc miles may exceed the number of miles hardened in a year for this reason.

Line No.

Q23. Why is there a variance between miles of DPLD arc wire removed and miles hardened in each year of the 4.8kV Hardening Program?

A23. There are fewer miles of DPLD arc wire removed because the DPLD system does not perfectly overlap with DTE Electric's distribution system.

Q24. Did the Company, as part of its filings in Case U-21860, present a plan to address the remaining miles of arc wire?[10]

A24. Yes, it did. The Company continues its commitment to address the remaining 253 miles of arc wire by leveraging both the 4.8kV Hardening Program and targeted conversions projects. The plan maintains the goal of complete removal of co-located DPLD arc wire targeted by 2030. As stated in Case U-21860, the plan expanded the scope of the Hardening Program to include an additional 38 miles of arc wire removal as compared to previous estimates of that work. As outlined in Table 3, this updated scope increases the total arc wire miles addressed by the 4.8kV Hardening Program to 1,060 miles and 215 miles addressed by the conversions program.

Table 3 - DPLD Arc Wire Removal

Program	Arc Wire Miles
4.8kV Hardening	1,060
Conversions	215
Total	**1,275**

Specifically, the remaining 215 miles of arc wire will be removed as part of City of Detroit Infrastructure (CODI): Garfield, CODI: Islandview Substation, CODI: Kent/Gibson Conversion, CODI: Howard Conversion, 4.8 kV CC: I-94 Substation and

[10] U-21534 Order, p. 103: "[i]n its next electric rate case, DTE Electric is directed to present a comprehensive plan for the removal of the remaining 253 miles of arc wire."

Line No.

1 Circuit Conversion (Promenade), and 4.8 kV CC: Zenon Substation and Circuit
2 Conversion – Phase 2.[11]
3
4 **Q25. Why is the Company dividing the remaining arc wire removal between hardening**
5 **and conversion projects?**
6 **A25.** The Company has determined that the decision to divide the remaining arc wire
7 removal between hardening and conversion projects is the most operationally sound
8 plan that avoids duplicate expense due to mobilization and demobilization. Hardening
9 all circuits to remove co-located arc wire would lead to some circuits being hardened,
10 only to be converted a few years later.
11
12 **Q26. Did the Company make progress toward removing the remaining arc wire and**
13 **have there been any modifications to the overall strategy for completing this**
14 **work?**
15 **A26.** Yes. In 2025, the Company hardened approximately 225 circuit miles, during which it
16 also removed approximately 206 circuit miles of arc wire. The Company is on track to
17 harden approximately 313 additional circuit miles and remove approximately 187
18 circuit miles of arc wire through the continuation of this program. Based on current
19 planning, the Company remains on schedule to complete this hardening initiative by
20 2027. The remaining arc wire will be eliminated through the Company's 4.8-kV
21 conversion program, as discussed earlier in my testimony.

[11]Exhibit A-12, Sch B5.4 Revised, p. 10, 11

Line No.

1 **IV. Small Wire Replacement Program**

2 **Q27. What is the Small Wire Replacement Program?**

3 **A27.** The Small Wire Replacement program is a new program that was created in response
4 to the Audit Report's recommendation that the Company expand mitigation of wire
5 downs to include more near-term proactive prevention. While programs such as
6 Hardening and PTMM focus on the pole and pole-top infrastructure, replacing wire has
7 in the past been performed either in full circuit conversions, or on an emergent basis
8 when wires failed during storms or other events.

9

10 The Small Wire Replacement program will target wire on 4.8kV circuits with a high
11 volume of primary wire down events. Small primary wire, where "small" is a reference
12 to the diameter of the wire that is inherently able to carry less load, is typically found
13 on the laterals (or ends) of circuits where large conductor was not originally needed
14 due to lower loading. Because of the aged infrastructure on many of our 4.8kV circuits,
15 pole and crossarm replacement will also be needed to support the larger conductor
16 replacement. Circuits will be prioritized by the number of wire downs experienced in
17 the past.

18

19 **Q28. What are the drivers for replacing small gauge wire?**

20 **A28.** Small primary wire is any wire conductor smaller than gauge 1/0 type that is non-ACSR
21 (Aluminum Conductor Steel Reinforced) that operates at a line-to-line voltage above
22 1000kV. These smaller conductor types were a typical gauge used when older circuits
23 were installed decades ago and are more prone to wire downs during inclement weather
24 and tree contacts, and are not consistent with current standards. For example, the
25 Company's system currently has approximately 2,900 miles of #6 Copper small wire,

Line No.

which accounts for only 9% of the Company's total conductor but contributes to 39% of the total wire downs.

Q29. What are the benefits of the Small Wire Program?

A29. This program aims to reduce wire downs. This will have the impact of improving reliability as well as safety. Replaced equipment will provide substantially greater mechanical strength, lower failure rates, and increased current-carrying capability.

Q30. What are the BCA analysis results for the Small Wire Replacement program?

A30. Small Wire Replacement investments were evaluated at a circuit level using the BCA framework described in Witness De Stigter's Exhibit A-28, Schedule R3 Revised. The BCA results indicate favorable cost-effectiveness for a substantial portion of the circuits analyzed. These quantitative results are supplemented by qualitative considerations related to safety, operability, and system hardening. Additional detail on the BCA methodology and results is provided in Exhibit A-28, Schedule R3 Revised, section 5.2.

Q31. How much small gauge wire exists on the Company's system that is being targeted with this program?

A31. The Company intends to target the replacement of approximately eight miles of small-gauge wire annually in both 2026 and 2027, from a total population of approximately 3,600 miles.

Line No.

Q32. What investment is required in the instant case to support the Small Wire Replacement Program?

A32. To fund the Small Wire Replacement program, which plans to replace approximately eight miles of small gauge wire in 2027, the Company anticipates needing an investment of approximately $10 million in projected test year.[12]

Q33. Does the Company have a timeline for the Small Wire Replacement Program?

A33. Yes. The Company is initiating the Small Wire Replacement program at a measured pace to develop a clearer understanding of execution timelines, constructability considerations, and resource requirements associated with replacing small wire across the distribution system. This initial phase will inform the appropriate long-term pace of work and support the development of a scalable implementation approach before expanding the program in future years. Table 4 below presents the Company's planned implementation.

Table 4 - Investment Plan for Small Wire Replacement, 2026- 2030 ($millions)

	2026	2027	2028	2029	2030	2026 – 2030 Total
Capital	10.0	10.0	10.0	18.0	20.0	68.0
Projected Range of Replacement Miles	5-20	5-20	5-20	9-36	10-40	34-136

Q34. What happens if the Company does not replace small gauge wire?

A34. If the Company does not replace small gauge wire, it would continue to operate portions of the distribution system with conductors that are not well-suited to current loading

[12] Exhibit A-12, Sch B5.4 Revised p.9 line 3

Line No.

and operating conditions, increasing the likelihood of equipment-related outages, wire-down events, and longer restoration times. Continued reliance on such conductors can also contribute to higher system losses and operational inefficiencies. As discussed above, these risks and performance impacts are reflected in the positive results of the Company's benefit-cost analysis, which demonstrate that a significant portion of Small Wire Replacement investments provide net system benefits.

V. Pole and Pole-Top Maintenance and Modernization Program ("PTMM")

Q35. What is the PTMM program?

A35. The PTMM (Pole and Pole-Top Maintenance and Modernization) program is designed to inspect and maintain overhead distribution equipment to enhance system reliability and resilience against weather, storms, and tree-related events. It involves inspecting all wood poles and pole-top equipment on distribution and subtransmission overhead circuits, and replacing any that fail inspection with stronger, potentially higher-class poles and upgraded pole-top materials. These new materials, such as fiberglass crossarms and polymer insulators, offer significantly greater mechanical strength and durability, resulting in fewer equipment failures and customer outages.

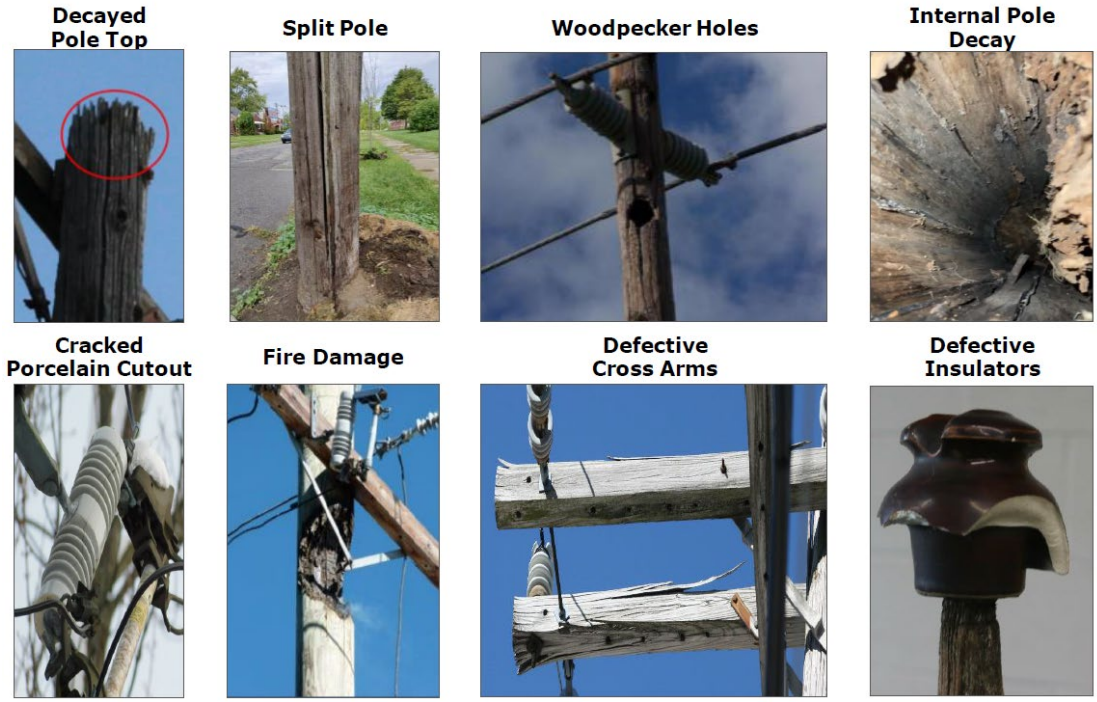
Overall, the goal of the Company's PTMM program is to inspect and maintain overhead distribution equipment in support of improving system reliability and resilience to weather and storms, while improving the safety of the system by reducing wire down events.

Line No.

Q36. What are the drivers of the Company's PTMM program?

A36. Approximately 70% of DTE Electric's grid infrastructure is overhead, with overhead equipment failures causing approximately 25% of all outages customers experience during all weather conditions and over 30% of all outages customers experience excluding Major Event Days ("MEDs"). Poles and pole-top equipment are some of the most critical parts of the distribution and subtransmission grid, and are continually exposed to harsh conditions (*e.g.*, tree strikes, ice, heat, rain, lightning, sunlight, and wind), causing them to degrade, weaken, and fail over time. Examples of equipment damage, also called inspection defects, are shown in Figure 2.

Figure 2. Pole and Pole-Top Defect Examples

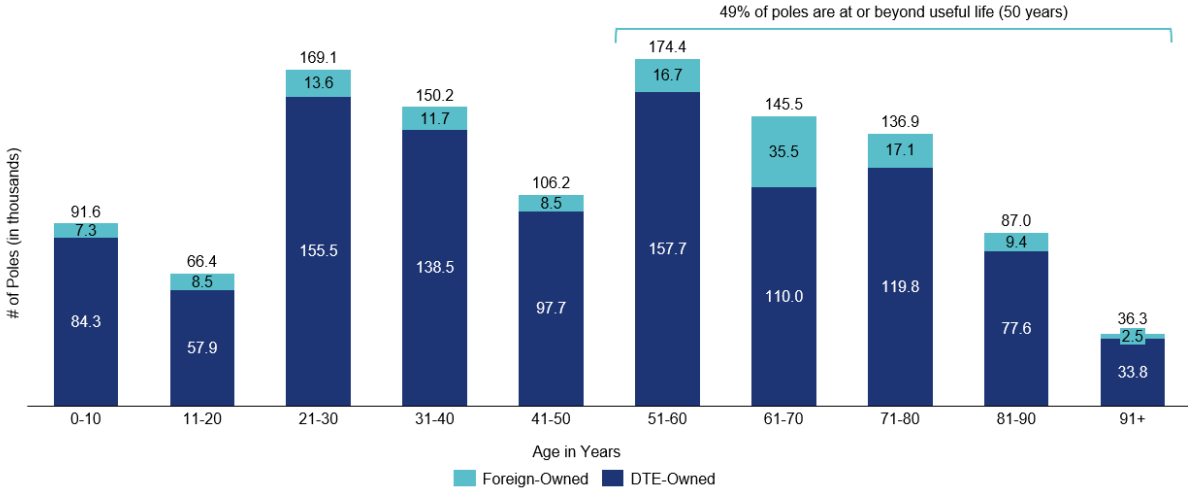


The Company has approximately 31,000 miles of overhead distribution and subtransmission lines, collectively containing approximately one million Company-

Line No.

owned wood poles and associated pole-top equipment. Utility poles have a useful life expectancy of approximately 40-50 years and have elevated failure risk as they age beyond their useful life. Useful life is a standard industry term that does not represent the actual life of a specific asset, but rather the age at which an installed asset is expected to experience increasing failure rates and deliver reduced performance, such that it is often more prudent to replace than to continue to repair and maintain. Figure 3 displays utility pole counts currently in use in the system by age range. It includes poles owned by DTE Electric as well as "foreign" poles (e.g., poles owned by other utilities such as AT&T and Comcast) that have DTE Electric assets attached. Notably, approximately 49% of the poles are more than 50 years old.

Figure 3. DTE Electric Poles by Age

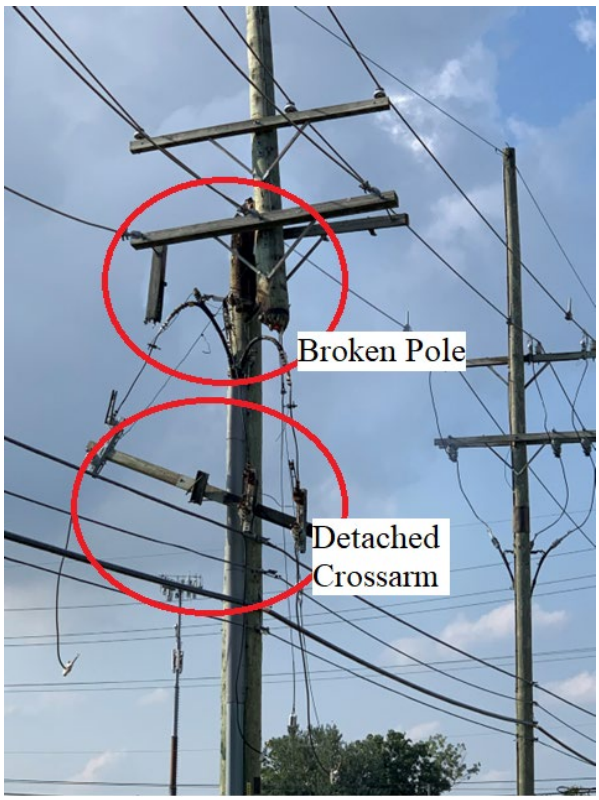


Aging and defective poles and pole-top equipment increase the risk of overhead equipment failures, which can subsequently cause outages. Pole and pole-top equipment are not replaced solely because of age but rather, replacements are largely based on inspection results. In addition to outages, examples of impacts that can occur

Line No.

in the event of pole and pole-top equipment failures include property damage, fires, and traffic accidents. Additionally, long and costly customer outages can result when this equipment fails unexpectedly from tree impacts or from other causes. Figure 4 displays an example of a pole-top equipment failure; specifically, a break in the pole itself and a detached crossarm.

Figure 4. Overhead Pole-top Failure – Example



Pole and pole-top maintenance programs, like the Company's PTMM program, are standard utility industry programs that inspect circuits for damaged or defective poles and pole-top equipment, replacing them before they cause failures.

Line No.

1 **Q37. What guidance from the Audit Report has the Commission adopted as an**
2 **appropriate cycle for PTMM?**
3 **A37.** In Case No. U-21305, Commission adopted the Audit Report's recommendation
4 regarding the PTMM cycle.[13] Specifically, the Audit Report recommended that the
5 Company implement "a four-to-five-year visual overhead circuit inspection program,
6 focusing on securing visual control of the system."[14]
7
8 **Q38. Did the Commission provide guidance on an appropriate cycle for PTMM in Case**
9 **No. U-21860?**
10 **A38.** Yes, the Commission noted that the Administrative Law Judge "found the move to a
11 five-year inspection cycle for pole tops to be essentially settled in light of the
12 Commission's findings in case Nos. U-21534 and U-21305."[15] The Commission
13 adopted "the ALJ's finding and conclusions" and "continues to see value in moving to
14 a five-year inspection cycle."[16]
15
16 **Q39. Did the Commission provide any additional guidance for PTMM in Case No. U-**
17 **21860?**
18 **A39.** Yes, the Commission directed the Company to "reevaluate the company's criteria for
19 determining what equipment, including poles, needs immediate replacement and what
20 equipment can be replaced in the future, and shall include these reevaluated criteria in
21 its next rate case."[17]

[13] Case No. U-21305 Commission Order, June 12, 2025, p. 7
[14] Case No. U-21305 Commission Order, June 12, 2025, p. 6
[15] Case No. U-21860 Commission Order, February 19, 2026, p. 132
[16] Ibid.
[17] Ibid, p. 481

Line No.

Q40. How is the Company responding to this guidance?

A40. The Company has reevaluated and refined its criteria for determining when equipment, including poles and pole-top assets, requires immediate replacement versus when replacement can be deferred based on risk. The Company increased the frequency of pole and pole-top inspections to enable earlier and more consistent identification of potential failure conditions. To balance the priorities of reliability, safety, and controlling costs, the Company has developed and implemented a process to assign pole-top inspection outcomes into three categories:

(1) safety or imminent outage;

(2) outage or failure likely; and

(3) future attention required.

Safety or imminent outage

For those pole-tops with an issue categorized as "safety or imminent outage," the Company will complete the repair as soon as possible. Examples of issues considered "safety or imminent outage" include, among others, broken poles, a transformer that is leaking oil, floating neutral or floating conductors, or situations where the conductor is not properly secured in the pole-top equipment.

Outage or failure likely

For those pole-tops with an issue categorized as "outage or failure likely," the Company will complete the repair within the PTMM program, meaning it will be included in the scope for replacement during the current-year PTMM program. Examples include broken, cracked, or disconnected pole-top equipment, holes on cross-arms, or poles with significant rotting.

Line No.

1 Future attention required

2 The last category, "future attention required," indicates that the issue is not an
3 immediate concern, but will be logged for re-inspection on the next cycle. The issues
4 in this category are not included in the scope for replacement during the current-year
5 PTMM program. Examples include porcelain cutouts that do not currently show signs
6 of damage and cracked or rotted pole-tops that do not have pole-top equipment that
7 needs to be replaced. Collectively, these three categories address the objective of
8 implementing the initial PTMM cycle in a cost-effective manner by prudently deferring
9 non-critical repairs that do not present an immediate reliability or safety risk.

10

11 The Company has also developed inspection specifications for consistent results. For
12 the goal of a 10-year inspection cycle for poles (*i.e.,* groundline pole inspection), the
13 Company will use its pole inspection specification[18] focused on ground line and
14 structural integrity of the poles themselves in the near-term. For the goal of a 5-year
15 inspection cycle for pole-tops, overhead lines, and associated equipment, the Company
16 will use its pole-top equipment inspection specification,[19] described above, which will
17 increase the frequency of inspection cycles to provide a more frequent assessment of
18 the condition of the overhead system.

19

20 **Q41. What is the scope of the groundline pole inspection and maintenance portion of**
21 **the PTMM program?**

22 **A41.** The Company's system has approximately 31,000 miles of overhead infrastructure that
23 would be covered as part of the groundline pole inspection and maintenance portion of
24 the PTMM program. To achieve a 10-year cycle, the Company plans to ramp up to

[18] Exhibit A-23, Sch. M9
[19] Exhibit A-23, Sch. M10

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inspect 3,100 miles/year. Groundline Pole Inspections will include the pole inspection and maintenance activities summarized below:

1. Inspecting poles for damage that will undermine structural integrity.
   (a) Poles installed within the last 20 years are visually inspected above grade.
   (b) Poles older than 20 years are visually inspected and excavated below grade level and physically tested.
2. Treating, reinforcing or replacing poles that fail inspection;
3. Trimming trees, as required.

Q42. What is the scope of the pole-top inspection and maintenance portion of the PTMM program?

A42. To achieve a 5-year cycle, the Company plans to ramp up to inspect 6,700 miles/year. Pole-top inspection will include the pole-top inspection and maintenance activities summarized below:

1. Visually inspecting pole-tops and pole-top equipment for damaged and/or defective equipment;
2. Replacing pole-top equipment that fails inspection with a higher-grade material, for example:
   (a) Damaged wooden crossarms are replaced with fiberglass crossarms.
   (b) Damaged/defective porcelain cutouts are replaced with polymer cutouts.

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(c) Damaged/defective porcelain insulators are replaced with polymer insulators.

3. Performing infrared inspections to identify conductor "hot spots" that can cause thermal degradation and potential thermal runaways. This condition, where an increase in temperature leads to higher power consumption and further temperature increases in a self-reinforcing cycle, can be a key indicator of potential conductor failure.

Q43. What investment levels are necessary to support the PTMM 5-year and 10-year cycles?

A43. In 2026, the PTMM program is currently funded through the IRM for $200 million. This level of investment will cover approximately 1,627 miles of both pole-top and groundline pole maintenance. In the instant case, the Company is requesting an increase – of $115.6 million for the projected test year (March 2027 through February 2028) and $10.6 million for the bridge period.[20] Looking beyond this proceeding, to fund pole-top and groundline pole maintenance on the 5-year and 10-year cycles, the Company anticipates a peak investment in 2030 of approximately $538.9 million[21] in 2026 dollars. In addition, incremental O&M is being requested for $6.1 million for the bridge and test year period, combined.[22]

Q44. What is the Company's plan to meet the PTMM 5-year and 10-year cycles?

A44. As shown in Figure 5 below, the Company developed a ramp-up plan to meet the PTMM 5-year and 10-year cycles that aligns with the Commission's Orders in U-21305

[20] Exhibit A-12, Sch B5.4 Revised, p.9 line 4
[21] Exhibit A-23, Schedule M11, line 10, column G
[22] Exhibit A-13, Sch C5.6 Revised, p1

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1 and U-21860. The overall annual investment level is anticipated to increase throughout
2 the first cycle as the Company addresses needed maintenance and then decrease as
3 circuits begin the second and subsequent cycles. Investment will continue to decrease
4 until all circuits are on a 5-year pole-top cycle. This is consistent with the Audit
5 Report's observation that appropriately recognized the cost associated with meeting
6 current expectations, specifically the report stated:

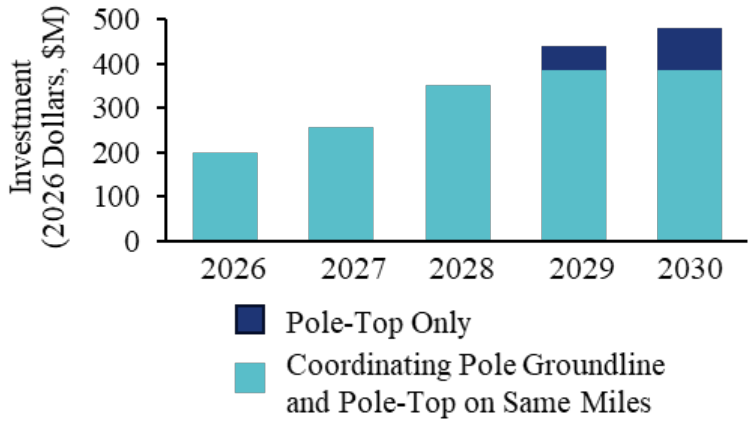
7 "[i]t also needs to be recognized that work, and therefore costs per year on a
8 four-year cycle, will be higher. However, once having addressed the entire
9 system, this cycle will lead to much reduced costs for the following years. Over
10 time, a shorter cycle will not produce greater work. However, it will remove
11 damaged and deteriorated poles and equipment more timely from the system
12 and reduce restoration costs." [23]

13 Note that Figure 5 shows forecasted investment in 2026 dollars without inflation
14 adjustments.

[23] Case No. U-21305, Audit Report, Part Two, Chapter 1, p. 43

Line No.

1 **Figure 5. PTMM Groundline Pole & Pole-Top Maintenance Investment**



2

3 **Q45. What capital investments are needed for the PTMM program to advance toward**
4 **the audit-recommended inspection and maintenance cycles?**

5 **A45.** To advance toward the audit-recommended five-year pole-top and 10-year pole
6 inspection cycles, the Company's ramp-up plan, as described above, requires increases
7 in annual PTMM capital investment from approximately $200 million in 2026 to
8 approximately $480 million in 2030 (in 2026 dollars), as summarized in Figure 5. This
9 increase reflects updated inspection results from 2025, including higher-than-expected
10 pole condemnation rates identified through field inspections.

11

12 Although the benefit-cost analysis discussed later in this testimony remains positive,
13 the higher level of remediation identified through inspections increases the expected
14 cost per mile of work. These investments will replace aging infrastructure with modern
15 assets, improving safety and reliability outcomes. At the same time, elevated
16 replacement rates may extend the time required to complete the initial five- and 10-year
17 inspection cycles. The Company will continue to monitor condemnation and failure
18 trends through 2026 and adjust future planning as appropriate.

Line No.

Q46. What does the Company project for the future investment levels needed to sustain the 5-year and 10-year inspection and maintenance cycles once those cycles are met?

A46. The Company anticipates that the investment levels associated with sustaining the 5-year pole-top and 10-year groundline pole inspection and maintenance cycles, once met, will continue to decrease after the first and second cycles due to failure rates going down as inspections and repairs are completed.

Q47. How does the Company prioritize circuits for the PTMM program?

A47. The Company is using the PTMM benefit cost analysis (BCA) process, as described by Witness De Stigter, to prioritize work. Specifically, the BCA data was prioritized by: (1) focusing on circuits that were trimmed recently to optimize the required program trimming; (2) applying an environmental justice (EJ) multiplier to the benefit-cost ratio (BCR) by circuit; (3) sorting the BCR high-to-low; (4) balancing workload between regions; (5) filtering circuits that were hardened or recently addressed by the PTMM program; and then (6) selecting all circuits on a selected substation area for operational efficiency. Using this methodology, the Company will leverage the PTMM BCA process to prioritize work while accelerating investment to meet the 5-year and 10-year cycles as described above.

This circuit-level prioritization complements the inspection process described earlier in my testimony by ensuring that conditions identified as safety or imminent outage and outage or failure likely are addressed with appropriate urgency, while circuits with conditions categorized as future attention required are reevaluated in subsequent

Line No.

inspection cycles to deliver the greatest reliability and safety benefits per dollar invested.

Q48. What are the BCA analysis results for the PTMM program?

A48. PTMM investments were evaluated at a circuit level using the BCA framework described in Witness De Stigter's Exhibit A-28, Schedule R3 Revised, section 5.1. The BCA results indicate favorable cost-effectiveness for a substantial portion of the circuits analyzed. These quantitative results are supplemented by qualitative considerations related to safety, operability, and system hardening. Additional detail on the BCA methodology and results is provided in Exhibit A-28, Schedule R3 Revised.

As indicated in Witness De Stigter's BCA report (Exhibit A-28, Schedule R3 Revised, section 5.1.4), a key benefit not included in the benefit-cost analysis is the mitigation of safety risks. Broken poles and wire downs pose a potential risk to crews and the public. The PTMM program reduces both of these potential risks, enhancing safety. Additionally, the program improves reliability by reducing outages and resiliency by strengthening the infrastructure against severe weather conditions, further justifying this investment.

For further information on the BCA analysis for the PTMM program, please see Witness De Stigter's testimony and Exhibit A-28, Schedule R3 Revised.

Line No.

Q49. What PTMM work did the Company complete in 2025?

A49. DTE Electric completed inspection and construction in excess of 950 circuit miles which included approximately 5,250 pole-top equipment locations and replaced just under 5,600 poles. Additionally, the program completed inspections on about 40,400 poles.

Q50. What is in the Company's 2026 and 2027 PTMM workplan?

A50. Case No. U-21860 approved investment of $200 million for the PTMM program in the IRM for 2026.[24] This investment will fund the 2026 workplan, which includes the replacement of poles and pole-top equipment across approximately 1,627 circuit miles. This translates to replacing or reinforcing approximately 10,270 poles and replacing pole-top equipment that has failed inspection. In this instant case, the Company plans to replace poles and pole-top equipment on approximately 1,743 circuit miles. This translates to replacing or reinforcing approximately 11,585 poles and replacing pole-top equipment that has failed inspection, as shown in Table 5.

Table 5 - PTMM 2026-2030 Workplan[25]

	2026	2027	2028	2029	2030	2026- 2030 Total
Circuit Miles	1,627	1,743	2,774	3,660	3,640	13,444
Total Poles Replaced / Reinforced	10,270	11,585	15,961	18,747	20,093	76,656
Capital Investment ($ millions)	200.0	263.4	376.8	482.6	540.0	1,862.8
O&M Investment ($ millions)	4.9	5.8	7.2	7.8	8.2	34.0

[24] Case No. U-21860 Commission Order dated February 19, 2026, pp. 385-386
[25] Totals may not match exactly due to rounding of the source data. Investment amounts are adjusted for inflation.

Line No.

Q51. What O&M investments are needed to support the PTMM program and achieve the targeted inspection cycles?

A51. In addition to capital investment, the PTMM program requires O&M funding to support inspections and pole testing, to advance toward the targeted inspection cycles. Consistent with the Company's ramp-up plan, as described above, O&M investment increases from approximately $4.9 million in 2026 to $8.2 million in 2030, as summarized in Table 5.

Q52. Are any PTMM investments included in the proposed Infrastructure Recovery Mechanism (IRM)?

A52. Yes. As described by Witness Chiu, the Company is proposing to recover a portion of PTMM investments through the IRM. Investments are partitioned between recovery through base rates, as proposed in Exhibit A-12, Schedule B5.4 Revised, and the Company's authorized IRM mechanism, in Exhibit A-33, Schedule X1. 2026 is the first year the approved IRM includes PTMM. In case No. U-21860, the Commission approved PTMM investments for recovery through the IRM for plan years 2026 and 2027 at $200 million each year. [26]

Table 6 - Proposed PTMM Investments (in millions)

	2025	2026	2027	2028
Base Rates	$107.7	$0.0	$63.4	$62.8
IRM	$0.0	$200.0	$200.0	$314.0
Total	**$107.7**	**$200.0**	**$263.4**	**$376.8**

[26] Case No. U-21860 Commission Order dated February 19, 2026, pp. 385-386

Line No.

PTMM investments beyond the test year, as described below, are proposed for inclusion in the IRM and shown in Exhibit A-33, Schedule X1. Witness Chiu discusses the background of the IRM and supports the inclusion of investments in the IRM.

Q53. What are the Company's expectations for investment in PTMM beyond the projected test year?

A53. As part of ongoing inspection and maintenance of the overhead system, the Company plans to continue to invest in PTMM beyond the projected test period covered in this case. The forecast of required investment on a calendar year basis[27] beyond test year is:

- 2028: $314.0 million
- 2029: $482.6 million
- 2030: $540.0 million

This reflects the full expected capital investment for the PTMM program from beyond the test year (March 1, 2028) to 2030 and is included in this case as the basis for the Company's IRM request supported by Witness Chiu. The first two months of 2028 are part of the projected test year and are therefore reflected on Exhibit A-12, Schedule B5.4 Revised. The PTMM circuit prioritization in the IRM will follow the method mentioned earlier in my testimony, which includes using the EJ multiplier to adjust the BCR.

[27] The indicated costs have been adjusted for inflation. The program's peak investment cited earlier in this testimony is stated in 2026 dollars.

Line No.

1 **VI. Frequent Outage Programs (CEMI)**

2 **Q54. What programs are included in Frequent Outage Programs?**

3 **A54.** In addition to strategic programs and projects to support overall grid reliability, the
4 Company has shorter term programs to address targeted pockets of the grid where
5 customers have experienced multiple outages. There are two primary programs under
6 Frequent Outage programs: the Customer Excellence (CE) program and the Strategic
7 Reliability Improvement program (SRIP).
8
9 The CE program was established to provide rapid solutions to small pockets of
10 customers experiencing poor reliability. The customers who are the focus of this
11 program are experiencing four sustained outages (SAIFI > 4.0), or nine momentary
12 outages (MAIFI > 9.0) per year. The prioritization method for circuits included in the
13 CE program relies on Advanced Metering Infrastructure (AMI) data to identify these
14 customers on a rolling 12-month basis. The CE program is designed to identify and
15 address issues more rapidly than other programs which rely on the annual analysis of
16 reliability events. In addition to reliability event data, the prioritization also includes an
17 evaluation of the time since the area's last tree trim was completed, any other planned
18 work on the circuits, as well as customer complaints.
19
20 Upon identification of a circuit that meets the CE prioritization criteria and is selected
21 for construction, the Company conducts a field patrol to assess both equipment and tree
22 conditions impacting reliability. After the patrol, the scope of work is developed for
23 the identified equipment and tree-related problems. In addition to the damaged or failed
24 equipment replacements and tree trimming, the scope of work also includes checking
25 operating equipment to ensure it is functioning properly, conducting fault studies to

Line No.

ensure fuses are properly sized, and installing additional equipment, such as reclosing devices and animal guards, to prevent future outages. The solutions require investments that range between $13,000 to $759,000 per circuit to implement.

The SRIP program performs improvements to either portions of a circuit (customer pockets), or entire circuits as appropriate. The primary distinctions between the CE and the SRIP programs are that circuits are normally selected for the SRIP program based on both a 12-month and a three-year average circuit SAIDI and SAIFI performance, MPSC complaints, and regional expertise on customer needs. In addition, the scope of work performed under the SRIP program is more comprehensive and typically requires investments between $26,000 to $1,761,000 per circuit to implement.

Q55. What is the Company's Pre-Summer Storm Strengthening (PS3) process?

A55. Beginning in 2021 after a summer with a high number of storms and associated customer outages, the Company began an annual process of analyzing the performance data of all circuits following each summer storm season. This analysis identifies circuits predicted to have the worst reliability performance. The PS3 process allocates the reliability challenged circuits to multiple programs including Vegetation Management (formerly called Tree Trim), PTMM, CE, SRIP, and 4.8kV Hardening, so that they receive improvements before the subsequent summer storm season.

Line No.

Q56. How may circuits have been addressed by the Frequent Outage Programs in recent years?

A56. For 2025, work was performed on 382 circuits within the Frequent Outage (CEMI) programs. The Company is planning to work on 130 circuits per year in 2026, 2027, and 2028 (Table 7).

Table 7 - Frequent Outage Programs (CEMI) 2025-2028

	2025 Actual	2026 Forecast	2027 Forecast	2028 Forecast
CE Circuits	219	96	130	130
SRIP Circuits	163	61	0	0
Total Frequent Outage Circuits	**382**	**130**	**130**	**130**

Q57. How do Frequent Outage programs (CEMI) benefit customers?

A57. Customers on circuits that have received Frequent Outage programs investments (CEMI) have experienced circuit improvements that in most cases significantly increased their electric service reliability. The CE program delivers quick, focused improvements for customers who have experienced poor reliability over a relatively short timeframe. Work typically includes verifying correct operation of field devices, conducting fault studies to ensure proper fuse sizing, and installing additional protective equipment — such as reclosers and animal guards — to prevent future outages. By contrast, SRIP takes a broader, multi-year view of reliability trends and addresses more complex, persistent challenges.

Line No.

1 **A. Frequent Outage: Wolfhill**

2 **Q58. Why was the Frequent Outage: Wolfhill project created?**

3 **A58.** The Wolfhill project was created to address persistent reliability and safety concerns
4 on two of the Company's worst-performing distribution circuits, DC 8838 and DC
5 8822. These circuits serve large geographic areas characterized by extensive overhead
6 construction, resulting in approximately 187 miles of overhead exposure that is subject
7 to weather-related damage and difficult to patrol, isolate, and restore during outage
8 conditions.

9

10 The project mitigates these risks by upgrading the substation configuration, splitting
11 the affected circuits, and installing additional automation to reduce the amount of
12 overhead exposure per circuit and improve sectionalizing capability. By reducing long
13 spans of overhead facilities and improving fault isolation, the project is expected to
14 reduce wire-down events, shorten outage duration, and enhance safety for both
15 customers and field crews, particularly in areas where faults are challenging to locate
16 and repair.

17

18 **Q59. What is the scope of the Frequent Outage: Wolfhill project?**

19 **A59.** The scope of the Wolfhill project is based on preliminary engineering analysis. More
20 detailed engineering will be performed beginning in 2026 and thereafter to further
21 define and finalize the scope of work. At a preliminary level, the project includes
22 installation of a new nine-position switchgear at the Wolfhill Substation. The scope
23 also includes installation of circuit switchers on Transformers No. 1 and No. 2;
24 extension of the secondary cables from Transformers No. 1 and No. 2 to a new Power
25 Distribution Center; and establishment of three new load-carrying circuits to split

Line No.

existing circuits. In addition, the project includes installation of approximately 1.1 miles of conduit; approximately 2.2 miles of EPR system cable for future load-carrying circuits, along with approximately one mile of system neutral; and installation of five station cable poles.

Q60. What are the customer benefits of the Frequent Outage: Wolfhill project?

A60. The Wolfhill project provides customer benefits primarily through improved safety and reliability. From a safety perspective, the project converts the three largest isolation (ISO) pockets[28] on the affected circuits, thereby eliminating areas with the highest exposure to wire-down conditions. These conditions present elevated safety risks to both the public and field personnel, particularly in remote areas where wire-down events can be difficult to detect and safely address.

From a reliability standpoint, the project adds three new load-carrying circuits, installs additional automation, and mitigates overhead exposure by replacing approximately 18.6 miles of overhead conductor with covered conductor. Reducing overhead exposure lowers the likelihood of weather-related faults, wire-down events, and extended restoration times, particularly on long overhead spans. Collectively, these improvements are expected to reduce customer outage duration by approximately 53 percent, as measured by SAIDI. In addition, the project alleviates circuit loading by transferring approximately 4.2 MVA to new circuits, further improving system performance and operational flexibility.

[28] A circuit segment beyond an isolation transformer with limited sectionalizing and restoration capability.

Line No.

1 **VII. Restoration Readiness and Community Resilience**

2 **Q61. What is Restoration Readiness and Community Resilience?**

3 **A61.** As stated earlier in my testimony, the Company established a new organizational
4 category, Restoration Readiness and Community Resilience, to further structure
5 projects within the Company's Resilience and Hardening pillar. The underlying
6 program included in this category is not new. The purpose of this category is to organize
7 and present the Company's investments that are intended to remediate failures that have
8 already occurred and to mitigate the risk of catastrophic failures in the future. Overall,
9 Restoration Readiness and Community Resilience projects are initiatives designed to
10 remediate equipment failures that have already occurred or to mitigate the risk of future
11 catastrophic failures. The Company's Restoration Readiness and Community
12 Resilience projects consist of the mobile fleet program.

13

14 **A. Mobile Fleet Program**

15 **Q62. What is the Mobile Fleet program?**

16 **A62.** The Mobile Fleet program includes investments to expand the Company's fleet of
17 mobile generation (Figure 6) used to quickly restore temporary power to customers
18 during major events such as substation failures and to support customers during
19 planned construction work when field crews must deenergize electric equipment for
20 safety reasons. In many major outage events, the mobile fleet allows for customer
21 restorations even before repairs begin on the failed equipment. Some events, such as a
22 substation transformer failure, may require months or even longer for permanent
23 repairs. The mobile fleet programs allow customers to have their power restored much
24 sooner. The mobile fleet includes portable generators, portable switchgear, portable
25 substations, portable ISO equipment, portable poles, energy storage trailers, staging

Line No.

and equipment storage sites to maintain rapid deployment capability, and the controls that allow these assets to work together cohesively during planned and emergency outage events.

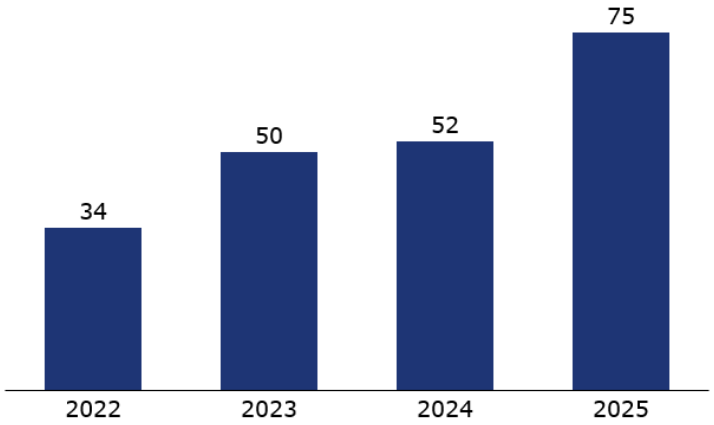
Figure 6. Portable Substation (left) & Mobile Generator (right)

Q63. How does the Mobile Fleet program benefit customers?

A63. The Mobile Fleet program gives the Company a short-to-medium term solution to major outage events and allows the Company to perform planned work, such as preventative maintenance on single-tap substations, without requiring customers to experience an outage while the work is being performed.

Line No.

1 **Figure 7. Deployment of Portable Equipment**



2

3 Since the beginning of 2022 to the end of 2025, DTE Electric has experienced 211
4 major events on the system, not including Storm events, causing loss of power for a
5 few hundred customers to over 10,000 customers per event. One example occurred at
6 Snover Substation in 2023. The Snover Substation is a single transformer, two-circuit
7 substation. The single substation transformer failed, resulting in loss of load for
8 approximately 1,100 customers for what could have been an extended outage. The load
9 of the circuits could not be transferred to neighboring circuits due to the configuration
10 of adjacent DTE Electric circuits and because the other adjacent circuits are owned by
11 other electric providers. The Company's short-term solution was to deploy portable
12 distributed generators to serve the load of the two circuits, restoring customers within
13 hours. The medium-term solution required the Company to install a portable substation
14 while permanent repairs were made at Snover Substation. The permanent repairs
15 required several days to complete, so the short- and medium-term use of mobile
16 equipment allowed customers to be restored to service faster. This example highlights
17 both the significant challenges to addressing a major event failure and the important
18 role the Mobile Fleet program plays in restoration of service to customers.

Line No.

1 Establishing permanent storage sites for portable substations is a critical element of the
2 Company's strategy to ensure that this equipment is maintained in a state of readiness
3 and can be deployed expeditiously to mitigate customer outages. Permanent storage
4 locations allow portable substations to remain connected to power, ensuring that
5 batteries and other systems are fully charged and operational. These sites also
6 incorporate specific infrastructure requirements necessary to support rapid deployment,
7 including oil containment and other environmental and safety controls. The Company
8 has established two permanent portable substation storage sites in Lapeer and Howell.
9 In 2026, the Company plans to add two additional permanent storage sites in Chestnut
10 and Riverview, followed by an additional site in Sandusky in 2027.
11
12 **Q64. What did the Commission conclude with respect to the Company's investments in**
13 **its Mobile Fleet program in the Final Order in U-21680?**
14 **A64.** The Commission found that "DTE Electric demonstrated the expenditures for the
15 mobile fleet category would shorten and avoid outages for customers in emergent
16 situations" and that "the company duly supported its request."[29]
17
18 **Q65. What Mobile Fleet program equipment is the Company planning to purchase in**
19 **this instant case?**
20 **A65.** The Company's plan for Mobile Fleet program investment in this instant case is a
21 continuation and extension of equipment previously authorized for cost recovery in
22 Case No. U-21860. By maintaining this approach, the Company seeks to preserve and
23 enhance the Mobile Fleet program's capability to effectively address both current
24 system needs and anticipated future operational needs.

[29] Case No. U-21860 Order dated February 19, 2026, p. 175

Line No.

In 2025, the Company substantially completed several key Mobile Fleet initiatives, including the Portable Diesel Generator 1 (PDG1), integration of portable control systems, procurement of additional connection skids and transformers, and development of portable switchgear protection-coordination capabilities. In 2026, the Company plans to complete the repackaging of PDG1, implement control system upgrades for PDG units and smaller skids, and evaluate and implement modifications necessary to support load-bank integration.

In 2027, planned activities include additional control system enhancements, implementation of time-based trip functionality for generators, completion of switching skids and associated transformers, and deployment of phase-balance control capabilities. Collectively, these investments will improve operational flexibility, enhance system protection and coordination, and ensure that Mobile Fleet assets remain capable of supporting rapid response and restoration activities.

VIII. Pilot: Strategic and Service Undergrounding

Q66. Why did the Company reclassify the Undergrounding program to the Resilience and Hardening Pillar?

A66. As mentioned earlier in my testimony, the Company reclassified the Undergrounding program to the Resilience and Hardening Pillar because the program's primary purpose is to enhance system resiliency and improve reliability by reducing outage risk associated with overhead infrastructure. These objectives are more directly aligned with the Resilience and Hardening Pillar, which focuses on mitigating reliability and resilience risks, rather than with the Redesign & Modernization Pillar, which is primarily oriented toward addressing capacity-driven system needs. The

Line No.

reclassification improves organizational clarity and more accurately reflects the nature and intent of the investment.

Q67. What is the Company's strategy around undergrounding pilot projects?

A67. The combination of aged overhead infrastructure and increasingly frequent and severe storms has resulted in reliability impacts for many of our customers. Undergrounding protects the electrical infrastructure from increased storm frequency and severity, thus providing resiliency and improving reliability. An undergrounded circuit also has safety advantages since there are no downed wires during storm events. Furthermore, over the life cycle of the assets, undergrounding can provide the benefit of reduced maintenance and repair costs due to eliminating the need for tree trimming, pole-top maintenance, and in most storm cases, trouble response.

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

To take advantage of this unique opportunity, the Company plans to conduct targeted undergrounding pilot projects in conjunction with planned system conversions and other coordinated infrastructure work. These circumstances create efficiencies by allowing undergrounding to be performed within an existing construction window, thereby reducing incremental costs associated with separate mobilization, permitting, traffic control, and customer outages. The Company will initially focus on locations where construction synergies can be achieved through coordination with municipal projects or other utilities.

Line No.

The main object of the pilot projects is to understand the challenges of undergrounding in a mature urban setting, define scenarios and situations when undergrounding can reap rewards in terms of safety, reliability, and resiliency benefits, and refine underground construction processes to gain cost efficiency on the installation. This approach will allow the Company to learn and to develop best processes for undergrounding in mature urban, suburban, and rural areas while focusing on reducing implementation costs. An additional goal is to analyze the longer-term benefits of undergrounding to better support a refined benefit-to-cost analysis in the future.

These pilot projects will also allow the Company to further demonstrate the benefits of undergrounding and determine when and where this design choice can be applied effectively.

Q68. Why did the Company initially choose to pilot undergrounding in a mature urban environment?

A68. An urban environment was initially selected to address the various operational challenges with respect to rear-lot construction, capture learnings from varying circuit topologies and customer densities, and improve storm response resiliency by reducing the number of customer services that come down in storms.

To achieve these objectives, the construction method utilized is to bore conduit for primary and secondary connections instead of trenching which can be more disruptive. To improve storm response and resiliency for single customer outages, often of longer duration in a large storm, the Company is also undergrounding customer service drops.

Line No.

1 The factors of the mature urban neighborhood environment served by DTE Electric in,
2 among other places, metropolitan Detroit, and undergrounding individual customer
3 services has resulted in the Company's undergrounding costs being higher when
4 compared with other utilities' scope of implementing undergrounding in a less
5 challenging rural environment with a reduced scope that does not include service drop
6 replacement.
7
8 **Q69. Has the Company completed any Undergrounding pilot projects?**
9 **A69.** Yes. In Case No. U-20169, the Company was asked to explore alternative
10 infrastructure designs to eliminate rear-lot overhead infrastructure and its associated
11 challenges. In order to study an alternative design (rear lot undergrounding), the
12 Company developed the Appoline pilot project that was completed in October 2023.
13
14 In order to study the front lot undergrounding design alternative and determine the
15 potential cost savings by working with other utilities, the Company developed the
16 Buffalo-Charles pilot project, the majority of which was completed in 2024.
17
18 Collectively, these pilot projects provided important lessons regarding constructability,
19 cost drivers, customer impacts, and coordination requirements. In particular, the pilots
20 demonstrated that undergrounding is more feasible and cost-effective in areas with
21 lower customer density, greater available space for construction, and reduced conflicts
22 with existing underground infrastructure. Based on these lessons learned, the Company
23 intends to focus future undergrounding evaluations and pilot efforts on locations where
24 site conditions and development patterns provide greater constructability and

Line No.

1 opportunities to achieve meaningful reliability and resilience benefits in a
2 cost-effective manner.
3
4 **Q70. What Underground pilots has the Commission approved?**
5 **A70.** In Case No. U-21860, the Commission approved two projects, Spruce (suburban
6 location) and Attica (rural location), described later in testimony. The Commission
7 agreed "with DTE Electric that undergrounding can provide safety benefits and can
8 potentially lead to reductions in emergent costs and outages" and went on to add that
9 the "Commission further agrees with the company that the Spruce pilot project presents
10 a unique opportunity to explore and learn from coordinating with municipalities to
11 reduce costs associated with removing and restoring roadways typically associated with
12 undergrounding in a suburban area."[30] Based on the benefits demonstrated and the
13 opportunity to gain experience coordinating with municipalities, the Commission
14 approved both pilot projects.
15
16 **Q71. What did the Audit Report say about the Company's Undergrounding Program?**
17 **A71.** The Audit Report found that the Company was "correctly approaching consideration
18 of a significantly scaled undergrounding program"[31] based on its experience from prior
19 pilot projects.[32] The Report further noted that the Company "has been engaged in
20 conducting one pilot and is appropriately planning a second, moderately scoped
21 project."[33]

[30] Case No. U-21860 Order dated February 19, 2026, p.391
[31] Audit Report, Part 2, at 85-86.
[32] The referenced pilots are the Appoline and Buffalo-Charles undergrounding projects
[33] Audit Report, Part 2, at 85-86.

Line No.

1 **Q72. Is the Company continuing to move forward with the two additional**
2 **undergrounding pilot projects?**
3 **A72.** Yes. The Company has completed the design phase for the two additional
4 undergrounding pilot projects. One pilot project (Attica) is being developed in a rural
5 area and the other (Spruce) in a suburban neighborhood. The investments for these
6 projects are shown in Exhibit A-12, Schedule B5.4 Revised, page 9, line 8.
7
8 **Q73. Has the Company engaged with customers and local communities on the two pilot**
9 **program projects in the instant case?**
10 **A73.** Yes. Related to the Spruce project, while participating in a community meeting in
11 September 2023, the Company learned of City of Ann Arbor community plans to
12 replace the roads within the impacted subdivision. This presented a unique synergy
13 opportunity to install electrical conduit for road crossings during spring and summer
14 2024 while the roads were being reconstructed. This allowed the Company to avoid the
15 cost impact of breaking down and restoring the roadway as those costs would be borne
16 by the community. Additionally, the Company has had multiple discussions with the
17 homeowner's association ("HOA") for the impacted subdivision to explain the impacts
18 of the project. Since Attica has a smaller number of customers impacted, the Company
19 directly communicated with each of the customers involved.
20
21 **Q74. Why was Attica selected as a pilot project?**
22 **A74.** Attica was selected as a pilot project to expand and enhance the Company's
23 understanding of strategic undergrounding for rural circuit topologies. While some
24 planning and constructing aspects of undergrounding in rural environments are less
25 complex than a densely developed and populated urban setting, rural circuits also can

present distinct challenges, including significant elevation changes, dense vegetation, wetlands, and wildlife impacts.

Additionally, lower customer density in rural areas influences both the type and quantity of equipment required for reliable service. The Attica circuit features a straight-line lateral section, which provides an opportunity to optimize undergrounding cost efficiency in a rural environment. Rural environments present fewer obstacles in construction, such as buildings, sidewalks, and dense utilities compared to an urban environment. Open fields provide an easier path of installation compared to rocky or paved urban landscapes, and fewer traffic control measures are required.

This approach is expected to be applicable to many rural laterals across the Company's service territory where overhead lines pass through more heavily treed areas. By strategically undergrounding select sections, the Company can minimize overhead infrastructure costs, reduce maintenance needs, and decrease outage risks caused by falling trees. The Attica circuit's poor SAIDI performance places it in the fourth quartile, making it a suitable pilot project to gain additional understanding of undergrounding in a rural environment.

Q75. What is the scope of the Attica pilot project?

A75. The Attica pilot project involves converting a distribution circuit lateral serving 37 customers from overhead to underground in Attica Township. The existing overhead primary, located in a deep right-of-way and surrounded by dense trees, poses significant challenges for crew accessibility. This project will relocate underground all primary overhead while keeping the customer services overhead. Given the low

Line No.

customer density in the area, the design helps the Company optimize costs for undergrounding in a rural environment. This scope is different than the two urban pilots that the Company has already completed.

Q76. What is the timing of the Attica pilot project?

A76. Attica pilot project engineering was completed in October 2024. Detailed design was completed in 2025. Project construction is expected to start in 2026.

Q77. Why was Spruce selected as a pilot project?

A77. The rebuild on a portion of the Ann Arbor circuit DC9836 Spruce was originally proposed as an overhead rebuild as part of the ISO Conversion Program. While participating in a community meeting in September 2023, the Company learned of City of Ann Arbor community plans to replace the roads within the impacted subdivision. This presented a unique synergy opportunity to install electrical conduit without the cost impact of breaking down and restoring the roadway as those costs would be borne by the community.

Q78. What is the scope of the Spruce pilot project?

A78. The Spruce pilot project will convert an area of 228 customers from overhead to underground to improve reliability by reducing overhead exposure to trees. Installation of approximately 2.5 miles of front-lot, single phase underground residential distribution cables will facilitate the removal of approximately 1.6 miles of overhead primary lines. All new infrastructure will be built to 13.2kV standards, with 4.8kV overhead equipment being removed upon project completion.

Q79. What is the timing of the Spruce pilot project?

A79. Spruce pilot project engineering and detailed design were completed in 2025. Project construction is expected to start in 2026.

Q80. Why does the Company believe it is important to continue to implement undergrounding pilot projects?

A80. The Company believes that undergrounding brings a set of unique benefits and is of high interest to our customers and other stakeholders. Undergrounding is the only investment option that fully eliminates the safety risk associated with downed wires and structures. Undergrounding provides the highest overall benefit in reducing emergent reactive costs and customer outages. Undergrounding is the most resilient option for severe weather-related events. Due to these advantages of undergrounding, the Company believes that it needs to conduct additional pilots to continue to learn and focus on reducing implementation costs to increase the overall benefit to cost ratio.

Learnings from these projects will be used to refine the current benefit cost models to help identify segments of overhead infrastructure that are good candidates for undergrounding. Furthermore, this approach will allow the Company to develop a more cost competitive undergrounding program.

IX. Substation Risk Projects

Q81. What are Substation Risk projects?

A81. Projects in this category are designed to remediate failures of substations that have already occurred, or to prevent catastrophic substation failures in the future. Substation risk events typically are caused by equipment failure (*e.g.*, transformer or switchgear),

Line No.

fires, or flooding. Because a substation typically supports several circuits, substation risk events often impact many customers. In addition to affecting a large number of customers, they can result in lengthy outages to repair or replace large equipment. An entire substation is difficult to restore, with methods often limited to Mobile Fleet program assets such as diesel generators and portable substations to provide temporary support, or switching load to adjacent substations if there is available jumpering capacity. The amount of adjacent substation jumpering that can be achieved, and how quickly it can be implemented, is dependent on several factors such as whether the substation is the same circuit voltage class, whether there is adequate existing capacity and cable/conductor size, and whether sufficient operating devices are already installed in the field. Substation Risk projects, as a result, target replacing at-risk switchgear, which includes the enclosure with breakers, relays, and wiring, within the substations to reduce the risk of major outages.

These Substation Risk projects are prioritized utilizing the Global Prioritization Model ("GPM"), as discussed in more detail in the testimony of Witness Kryscynski. The GPM is applied to substations where deployment of Mobile Fleet program assets cannot restore the entire substation load, resulting in customer outages exceeding 24 hours in the event of a failure. Details of the projects included in this instant case can be found below and in Exhibit A-23, Schedule M3.

Q82. What Substation Risk projects are part of this proceeding?

A82. There are twelve substation risk programs and/or projects that are part of the current proceeding—two that are flood-related substation risk projects and ten that are failed equipment-related substation risk projects. The two flood-related substation risk

Line No.

1 projects include: (A.1) McGraw project and (A.2) Flood Defense program. These
2 projects are continuations of the same projects for which the Commission allowed cost
3 recovery in Case No. U-21860. The 10 failed equipment-related substation risk projects
4 include: (B.1) Apache project; (B.2) Belleville Switchgear Decommission project;
5 (B.3) Chestnut project; (B.4) Drexel project; (B.5) Hood project; (B.6) Lancaster
6 project; (B.7) Savage Switchgear Replacement project; (B.8) Seville project; (B.9)
7 Sterling project; (B.10) Waterman project. These projects include both new initiatives
8 and continuing investments previously authorized by the Commission.
9
10 **Q83. What has the Commission concluded regarding the Substation Risk Projects in**
11 **U-21860?**
12 **A83.** The ALJ found that "the Company's planning, justification, and costs for these projects
13 are reasonable and prudent"[34] and the Commission found the ALJ's recommendation
14 is well-reasoned and supported by the record. The Commission goes on to say that BCA
15 was not necessary as "the company sufficiently supported the expenditures…[and]
16 finds that the benefits of the substation risk project are evident based on the information
17 DTE provided, namely that these projects will replace failed (or nearly failing)
18 equipment and that doing so will prevent outages to a substantial number of
19 customers."[35]

[34] Case No. U-21860 Proposal for Decision, December 22, 2025, p. 205
[35] Case No. U-21860 Order dated February 19, 2026, pp. 172-173

Line No.

1 **A. Flood-related Substation Risk Projects**

2 **A.1. Substation Risk: McGraw**

3 **Q84. Can you describe the drivers of the Substation Risk: McGraw project?**

4 **A84.** Record heavy rains in June 2021 led to significant catastrophic flooding in the McGraw
5 substation. The sub-grade part of the substation, which houses the station's busses and
6 breakers, was engulfed in storm water. The result was a failure of position breakers,
7 busses, transfer busses, and house service panels, with the substation experiencing a
8 total loss of load carrying ability. That failure, in turn, caused 6,000 customer outages,
9 lasting between 16 hours to 5 days based on the ability to restore power.

10

11 The Company's initial emergency response included a mix of jumpering load away
12 from McGraw Substation to adjacent substations, and use of the Mobile Fleet Program
13 portable generation equipment. All customers were placed back on utility power within
14 two weeks after the flooding event by means of station jumpering and breaker
15 replacement.

16

17 The substation, however, continued using some Mobile Fleet program equipment and
18 a temporary overhead circuit constructed on city of Detroit and MDOT property to
19 bypass damaged and inoperable substation equipment, until a permanent solution was
20 constructed on DTE Electric property.

21

22 **Q85. What actions did the Company take to prevent similar flooding events at McGraw**
23 **and other, similar substations?**

24 **A85.** After the initial emergency response, the Company's engineers and field personnel
25 assessed the substation's condition, as well as the long-term plans for the McGraw

Line No.

Substation and surrounding circuits. The Substation Risk: McGraw project was created after these assessments, with the goals of preventing future failures due to flooding and returning customers to normal utility service.

Additionally, because of the flooding at McGraw Substation, as well as the increase in frequent and severe weather events causing flooding, the Company hired a third-party contractor to survey its other substations with sub-grade equipment to evaluate the risk of potential catastrophic flooding at those locations. The result of the third-party assessment was the Substation Risk: Flood Defense program that is discussed later in my testimony.

Q86. What is the scope of the Substation Risk: McGraw project?

A86. The scope of the Substation Risk: McGraw project is to:

i) Install new substation equipment on the second level of McGraw Substation, including a new circuit feeder and Automatic Throwover (ATO) breakers, as well as new relays and voltage control panels. As part of this installation, network/SCADA capabilities have been installed to increase reliability. Additionally, while all critical equipment has been moved out of the sub-grade level of the station, sump pumps and a manual diversion valve have been installed to improve response to any potential flooding in the basement.

ii) Provide for exterior expansion of the substation. After considerable effort working with government entities that took a significant amount of time, and in light of limited options, in 2024, the Company acquired land parcels and vacated right-of-way from the City of Detroit and MDOT to allow exterior expansion for equipment that will be removed from the basement.

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iii) Construct exterior expansion of substation equipment including two 24-4.8kV 10/12 MVA transformers with circuit switcher protection and a nine-position power delivery center (PDC) and network/SCADA capabilities installed to increase reliability.

iv) Decommissioning and removal of failed substation equipment. The Company anticipates completing decommissioning and removal of failed substation equipment in 2026. Additionally, the 2026 scope includes follow-up work for the expansion including manhole repair, fencing, finish oil containment, and storm drainage work.

More details of this project can be found in Exhibit A-23, Schedule M3.

Q87. What are the customer benefits of the Substation Risk: McGraw project?

A87. The Company has made continued progress on the McGraw project and returned customers served by the McGraw Substation to normal utility service, eliminating the continued reliance on mobile generation equipment and the temporary pole farm, thereby improving the reliability of service for all affected customers. The project also significantly reduces the risk of future flooding-related outages by relocating all critical equipment necessary to serve customers to the second floor of the substation or to exterior locations, rather than the basement. The project will be completed in 2026. Completion of the permanent utility infrastructure has also allowed for the removal of large temporary equipment.

1 **Q88. What has the Commission concluded regarding the continued investment in the**
2 **Substation Risk: McGraw project you describe above in this instant case?**
3 **A88.** The Commission concluded that the Substation Risk projects, including the McGraw
4 project, provide clear and demonstrable benefits. Specifically, the Commission found
5 that "the benefits of the substation risk projects are evident based on the information
6 DTE Electric provided—namely, that these projects will replace failed (or nearly
7 failing) equipment and that doing so will prevent outages to a substantial number of
8 customers."[36].
9
10 **A.2. Substation Risk: Flood Defense Program**
11 **Q89. What is the Substation Risk: Flood Defense program?**
12 **A89.** As I explained above, the Substation Risk: Flood Defense program was created
13 following the third-party's flood risk analysis of the Company's Class C and D
14 substations, following flooding events at the Company's substations, including the
15 McGraw Substation flooding in 2021.
16
17 The Company's Class C and D substations[37] were constructed in the 1930s and 1940s
18 and were designed to contain critical distribution assets underground in their
19 basements. These older substation designs rely on water-cooled equipment that
20 requires a sewer connection, making them vulnerable to catastrophic failures due to
21 abnormally heavy rains that can cause rapid flooding events. As part of the flood risk
22 analysis, the Company determined that five substations (Walker, Orchard, Madison,

[36] Case No. U-21860 Order dated February 19, 2026, p. 174
[37] A Class C substation is a general-purpose substation with three or more radially fed 24 to 4.8kV transformers, a 4.8kV transformer bus, a 4.8kV transfer bus, and a 4.8kV linkage bus, operated together to provide a parallel-operated service with a maximum degree of continuity. A class D substation is designed to include the installation of one or more 120 to 40/24kV transformers and several 40/24kV circuits. Class D substations are usually designed for two or more 120kV buses, 120 to 40/24 kV transformers, and 40/24kV buses. The design may also include 345 and 230kV buses and switching and associated transformation to 120kV.

Line No.

Frisbee, and Scotten), serving approximately 17,000 customers, were at elevated risk and required flood mitigation measures. To address the risk to these substations, the Company developed the Substation Risk: Flood Defense program to limit or prevent water intrusion in vulnerable substations by performing the following work at the five substations:

- Install one-way backflow prevention valves on existing sewer connected dewatering systems;
- Install emergency dewatering pumps to discharge at ground level during sewer backup events;
- Seal conduit to help prevent water penetration into the substation; and
- Replace existing primary pumps, at Frisbee, Madison, Scotten, and Orchard substations.

The project will be completed in 2026, with total program costs for the five substations estimated at approximately $5.6 million. Of this amount, approximately $1.2 million is associated with work on the five substations in 2026. Additional details of the program are provided in Exhibit A-23, Schedule M3.

Q90. What are the customer benefits of the Substation Risk: Flood Defense program?

A90. The Substation Risk: Flood Defense program investments will reduce the risk of catastrophic failure at the five identified at-risk substations, thus reducing the risk of extended outages for approximately 17,000 customers (98% are considered vulnerable from an EJ perspective), as well as the costly subsequent repairs.[38]

[38] See Witness Kryscynski testimony for definition of vulnerable customer.

Line No.

1 **B. Failed Equipment-Related Substation Risk Projects**

2 **Q91. Can you explain how failed equipment-related substation risk projects differ from**
3 **the flood-related substation risk projects you just described?**

4 **A91.** While the Company's flood-related substation risk projects are tied to addressing
5 substations that have experienced or are at risk of experiencing catastrophic failures
6 caused by flooding, the Company's failed equipment-related substation risk projects
7 address substations currently experiencing equipment failures that have different
8 causes.

9

10 **B.1. Substation Risk: Apache**

11 **Q92. Why was the Substation Risk: Apache project created?**

12 **A92.** A breaker position inside the switchgear failed at the Apache Substation in 2015 which
13 resulted in a significant area-wide outage affecting approximately 11,000 customers
14 with 81% of affected customers being restored within 16 hours. The main business
15 district of Troy, as well as surrounding commercial and residential areas were without
16 electrical service for a prolonged period of time.

17

18 An assessment was performed after emergency repairs were made, which concluded
19 that the remaining switchgear breakers were at-risk of a similar failure. A second
20 catastrophic failure could result in the loss of all switchgear positions, and up to 16
21 MVA of stranded load. Stranded load occurs when customers cannot be restored by
22 jumpering or transferring customers to an adjacent circuit or substation leading to
23 prolonged customer outages across the entire substation area. In the example of
24 Apache, while some load can be transferred to adjacent circuits, up to 16 MVA cannot

Line No.

be transferred. The Substation Risk: Apache project was initiated to invest in appropriate replacements to prevent this potential second catastrophic failure.

Q93. What is the scope of the Substation Risk: Apache project?

A93. The scope of the Substation Risk: Apache project is to:

- Replace (1) at-risk 19-position switchgear with (2) new 12-position switchgear
- Replace (3) circuit switchers with S&C 2020 circuit switchers
- Build system cable termination on new switchgear for all 13 circuits
- Decommission the existing at-risk 19 position switchgear once load is cut over to new switchgear
- Install 12-5" conduit supporting substation exits
- Build (1) two-way manhole
- Build (9) three-way manholes
- Remove ~8,584 feet of old EPR (ethylene propylene rubber) and XLPE (cross-linked polyethylene) cable
- Install ~9,333 feet of new EPR cable
- Replace (19) disconnect switches with pole-top switches at the station cable poles

Q94. What are the customer benefits of the Substation Risk: Apache Project?

A94. The new switchgear will reduce the risk of catastrophic substation failures and extended duration area-wide customer outages. The replacement of one at-risk 19-position switchgear with two new 12-position switchgear will also provide load relief to Apache circuits that exceed day-to-day limits. The project is anticipated to be completed in 2026.

Line No.

B.2. Substation Risk: Belleville Switchgear Decommission

Q95. Why was the Substation Risk: Belleville Switchgear Decommission project created?

A95. In the beginning of 2020, DTE Electric's Engineering team identified the 4.8kV Belleville switchgear as being at end of life. Breakers inside the switchgear required multiple repairs over the course of 5 years and there are no breaker replacements if they were to fail. Control wiring inside the cubicle also required re-wiring which involved extended planned shutdowns. The Belleville substation did experience a switchgear failure in 2022 which led to the condemnation of Bus 11 and limited operability. The Company's equipment engineers determined that the switchgear at Belleville substation is at-risk of further failures due to being at end of life and needs to be fully decommissioned.

Q96. What is the scope of the Substation Risk: Belleville Switchgear Decommission project?

A96. The scope of the Substation Risk: Belleville Switchgear Decommission project is to bypass Belleville's 4.8kV switchgear by installing an overhead recloser just outside of the substation, converting the 4.8kV portion of Belleville substation from a Class A[39] to a Class T[40] substation, and reconfiguring the (3) load-carrying circuits and throw-over circuit into (2) load-carrying circuits. This project was completed in 2024. More details of this project can be found in Exhibit A-23, Schedule M3.

[39] Class A substations are general-purpose facilities with switchgear that distribute multiple circuits from a single substation in heavily loaded areas.
[40] Class T - One or two transformer substation served by individual circuits.

Line No.

1 **Q97. What are the benefits of the Substation Risk: Belleville Switchgear Decommission**
2 **project?**
3 **A97.** Decommissioning and removing the partially failed, at-risk 4.8kV switchgear at
4 Belleville substation and then reconfiguring the distribution circuits has enabled
5 continued service for approximately 1,300 customers. This work has reduced the risk
6 of extended outages for these customers if the switchgear were to experience another
7 failure in the future.
8
9 A future 4.8kV Conversion project at Belleville substation is addressed in Witness
10 Stowe's testimony which will convert these circuits to 13.2kV and remove any
11 remaining 4.8kV equipment at Belleville substation.
12
13 **B.3. Substation Risk: Chestnut**
14 **Q98. Why was the Substation Risk: Chestnut project created?**
15 **A98.** The Chestnut substation has a single 19-position switchgear that is a single point of
16 failure. A switchgear failure could result in the loss of all switchgear positions and a
17 potential stranded load of 35 MVA with limited jumpering options, which would affect
18 approximately 6,000 customers across three cities. This type of potential failure is
19 similar to the Apache substation failure described earlier in my testimony, which would
20 result in a long-duration outage for the affected customers. The switchgear itself was
21 evaluated to be at high risk of failure based on a combination of years in service (53
22 years) and an equipment type that has experienced issues[41] (GE air breaker). The
23 Chestnut project was initiated to mitigate the combination of high equipment risk and

[41] Lack of ongoing Original Equipment Manufacturer (OEM) support and readily available replacement parts increase maintenance burden and operational risk.

Line No.

up to 15 MVA of stranded customer load by replacing the single at-risk 19-position switchgear with two new 12-position switchgear.

Q99. What is the scope of the Substation Risk: Chestnut project?

A99. The scope of the Substation Risk: Chestnut project is to replace one at-risk 19-position switchgear with two 12-position switchgear, replace and relocate three capacitor banks, install approximately 500 feet of 15-5" concrete encased duct bank, install approximately 10,000 feet of EPR cable and associated branch and straight joints, and install 17 OMNI-Rupters.[42] More details of this project can be found in Exhibit A-23, Schedule M3.

Q100. What are the benefits of the Substation Risk: Chestnut project?

A100. The new switchgear will reduce the risk of catastrophic substation failures and extended duration area-wide customer outages and will provide increased capacity to serve 18 distribution circuits, while the old configuration was only capable of serving 12 distribution circuits. The project is anticipated to be completed in 2027.

Q101. Was investment in the Substation Risk: Chestnut project requested in previous rate cases?

A101. Yes. The Substation Risk: Chestnut project was included in Exhibit A-12, Schedule B5.4 Revised and Exhibit A-23, Schedule M4 exhibits for Case Nos. U-21297, U-20836, U-20561, U-20162, and U-21860.

[42] OMNI-Rupters are pole-mounted, three-phase load-interrupter switches used on overhead distribution feeders to sectionalize circuits and interrupt load current.

Line No.

B.4. Substation Risk: Drexel

Q102. Why was the Substation Risk: Drexel project created?

A102. Switchgear position I at Drexel substation experienced a failure in July 2016 which resulted in a fire and damaged several positions in the Drexel switchgear. Approximately 7,500 customers are normally served by Drexel substation and over 3,000 customers were transferred to adjacent substations to restore service. Replacing the switchgear and restoring customers to their normal point of service will restore operability and reduce loading constraints in the area.

Q103. What is the scope of the Substation Risk: Drexel project?

A103. The scope of the Substation Risk: Drexel project is to commission and load transfer all DC circuits, install the circuit switcher, remove existing switchgear from the substation, and install SCADA and network communication. More details of this project can be found in Exhibit A-23, Schedule M3.

Q104. What are the benefits of the Substation Risk: Drexel project?

A104. Completing the Drexel switchgear replacement project will restore the area to its normal configuration which reduces load on adjacent circuits and substations that have been temporarily serving Drexel customers since 2016. Decommissioning and removing the partially failed switchgear mitigates the risk of additional failures and extended outages for the area. The project was completed in 2025.

Line No.

1 **B.5. Substation Risk: Hood**

2 **Q105. Why was the Substation Risk: Hood project created?**

3 **A105.** The transformer at Hood skid-mount substation[43] experienced two failures and after a
4 review by the Company's engineers was determined unrepairable. Approximately
5 2,000 customers have been temporarily transferred to adjacent circuits to continue
6 service. A replacement transformer is not available for the skid mount substation to
7 restore the area to normal configuration; therefore, replacement of the skid-mount
8 substation with a new substation is necessary.

9

10 **Q106. What is the scope of the Substation Risk: Hood project?**

11 **A106.** The scope of the Substation Risk: Hood project is to:

12 - Remove failed skid-mount substation and infrastructure
13 - Construct a new two transformer substation consisting of two modular power
14 delivery centers (PDC)
15 - Construct a new two transformer (2-15/20/25MVA transformers, two modular
16 power delivery center) substation
17 - Extend approximately 220 feet of 2–5-inch conduit
18 - Extend approximately 720 feet of EPR cables
19 - Install (6) pole-top switches (PTS) to support station cable poles
20 - Perform load transfers to re-establish Hood circuits to normal configuration

21 More details of this project can be found in Exhibit A-23, Schedule M3.

[43] A skid-mount substation is a compact substation with a transformer and associated equipment mounted on a steel skid for modular installation and replacement.

Line No.

1 **Q107. What are the benefits of the Substation Risk: Hood project?**

2 **A107.** Restoring the area to normal configuration will enable the Company to return all
3 circuits, approximately 2,000 customers, to normal operating condition and restore
4 system redundancy in the event of future outage events. Additionally, the new
5 substation will provide increased capacity for the area, from 13 to 40 MVA and
6 supports Pontiac conversion by establishing capacity for two additional circuit
7 positions to transfer customers from the 8.3kV infrastructure. The project is anticipated
8 to be completed in 2026.

9

10 **B.6. Substation Risk: Lancaster**

11 **Q108. Why was the Substation Risk: Lancaster project created?**

12 **A108.** The Lancaster project was created in response to a 2025 fire at the Lancaster Substation
13 in Southfield, Michigan (a large suburb of Detroit) that resulted in catastrophic
14 switchgear failure and disrupted electric service to more than 1,600 customers.
15 Following the event, the Company implemented emergency operating measures by
16 rerouting load to unaffected Lancaster circuits and adjacent substations. While these
17 actions restored service, they required operating certain circuits beyond their
18 Day-to-Day Ratings and increased the risk of low-voltage conditions.

19

20 As a result of the fire, the substation is currently operating in an abnormal configuration
21 due to irreparable damage to one of its primary switchgear units. The existing
22 configuration relies on a single across-the-aisle switchgear that is approaching the end
23 of its expected service life of approximately 40 years. The Company initiated the
24 Lancaster Substation Risk project to replace the damaged switchgear and restore the

Line No.

substation to a normal operating configuration with expanded capacity, thereby mitigating reliability risks and alleviating overloading on nearby substations.

Q109. What is the scope of the Substation Risk: Lancaster project?

A109. The scope of the Lancaster project includes the decommissioning and removal of damaged switchgear; installation of a new breaker for the throwover circuit; installation of a new transformer; and installation of new Power Distribution Centers (PDCs). The project also includes associated electrical and civil work, including required cables, manhole covers, fencing, and conduit necessary to support the upgraded substation configuration.

Q110. What are the customer benefits of the Substation Risk: Lancaster project?

A110. The Lancaster project provides several customer benefits. The project reduces the risk of equipment-related failures by replacing aging across-the-aisle switchgear with modern PDCs equipped with supervisory control and data acquisition (SCADA) capabilities. These improvements enhance protection and automation, thereby reducing the frequency and duration of customer interruptions.

In addition, the project adds spare circuit positions, which will support future load growth and provide load relief for nearby overloaded substations. Finally, the project restores the Lancaster Substation to a standard operating configuration, improving overall system reliability. The project is anticipated to be completed in 2028.

Line No.

1 **B.7. Substation Risk: Savage Switchgear Replacement**

2 **Q111. Why was the Substation Risk: Savage Switchgear Replacement project created?**

3 **A111.** The Savage substation has a single 16-position switchgear that is a single point of
4 failure. A switchgear failure could result in the loss of all switchgear positions and a
5 potential stranded load of 30 MVA with limited jumpering options, which would affect
6 approximately 3,000 customers throughout Troy. This type of failure would result in a
7 long-duration outage for the affected customers. The switchgear has been determined
8 to be at-risk of failure based on a review by the Company's equipment engineers. The
9 combination of high equipment risk and high stranded customer load was why the
10 Savage project was initiated. By splitting the existing single 16-position switchgear
11 into two new separate 9-position switchgears, the equipment risk is reduced and the
12 amount of potentially stranded load (15 MVA) due to a single point failure is also
13 reduced.

14

15 **Q112. What is the scope of the Substation Risk: Savage Switchgear Replacement**
16 **project?**

17 **A112.** The scope of the Substation Risk: Savage Switchgear Replacement project is to:

18 • Remove the existing parking area north of existing substation fence –
19 approximately 7,800 sq. ft.
20 • Extend the substation fence approximately 300 feet
21 • Perform site preparation and below grade work for an expanded substation yard
22 • Install concrete pads for new switchgear and three (3) 6 MVAR bus capacitor
23 banks
24 • Install two (2) 9-position 2-high switchgear

Line No.

- Install conduit and system cable to existing circuit cables feeding Savage circuits and neighboring circuits to enable jumper contingency
- Extend overhead lines 770 feet to establish two (2) portable ready locations
- Install two (2) sets of 3-333KVA regulators
- Decommission and remove an existing 1960s vintage continuous line-up of one (1) 16-position switchgear.

This project is anticipated to be completed in 2027. More details of this project can be found in Exhibit A-23, Schedule M3.

Q113. What are the benefits of the Substation Risk: Savage Switchgear Replacement project?

A113. The new switchgear will reduce the risk of catastrophic substation failures and extended duration area-wide customer outages. It will also provide increased capacity to serve 12 distribution circuits while the old configuration was only capable of serving 10 distribution circuits.

Q114. Was investment in the Substation Risk: Savage Switchgear Replacement project requested in previous rate cases?

A114. Yes. The Substation Risk: Savage Switchgear Replacement was included in Exhibit A-12, Schedule B5.4 Revised and Exhibit A-23, Schedule M4 exhibits for Case No. U-21860.

Line No.

B.8. Substation Risk: Seville

Q115. Why was the Substation Risk: Seville project created?

A115. Position B at Seville experienced a failure in 2023 and after a review by the Company's engineers was determined unrepairable. Approximately 1,500 customers have been temporarily transferred to adjacent circuits to continue service. No spare positions currently exist at Seville substation to restore the area to normal configuration; therefore, switchgear replacement is necessary.

Q116. What is the scope of the Substation Risk: Seville project?

A116. The scope of the Substation Risk: Seville project is to:

- Replace one (1) failed 7-position switchgear with one (1) 12-position switchgear
- Install new transformer secondary cables
- Perform load transfers to re-establish Seville circuits to normal configuration

More details of this project can be found in Exhibit A-23, Schedule M3.

Q117. What are the benefits of the Substation Risk: Seville project?

A117. Restoring the area to normal configuration will allow the Company to return all circuits to normal operating condition and restore system redundancy in the event of future outage events. Additionally, the new standard 9-position switchgear will provide two spare circuit positions for future use to support customer growth, as necessary.

Line No.

1 **B.9. Substation Risk: Sterling**

2 **Q118. Why was the Substation Risk: Sterling project created?**

3 **A118.** The Sterling project was created to address both reliability and capacity concerns at the
4 Sterling Substation. The substation is currently served by a single switchgear
5 arrangement that represents a single point of failure. A failure of this switchgear could
6 result in the loss of all switchgear positions and strand load with limited load-transfer
7 options, potentially affecting approximately 12,000 customers in the Sterling Heights
8 area and resulting in a prolonged outage. Based on a review conducted by the
9 Company's equipment engineers, the existing switchgear has been determined to be at
10 risk of failure.

11

12 In addition, the project addresses capacity and loading constraints at the Sterling
13 Substation through expansion. The substation serves nine load-carrying circuits, one of
14 which has operated as high as 97 percent of its normal Day-to-Day rating, while three
15 additional circuits have exceeded the Company's capacity limit of 8 megavolt-amperes
16 (MVA) for a 13.2-kilovolt circuit. The service area is experiencing redevelopment and
17 steady load growth, including on circuits already operating near or above their nominal
18 limits. These conditions create reliability risks, as load cannot be transferred to adjacent
19 circuits without causing similar loading issues. Further, the substation currently has no
20 available positions to establish new circuits to provide load relief or additional capacity,
21 limiting the Company's ability to reroute load during contingency conditions.

22

23 **Q119. What is the scope of the Substation Risk: Sterling project?**

24 **A119.** The scope of the Substation Risk: Sterling project is:

25 - Installation of a new 120-13.2 kV substation

Line No.

- Decommissioning of the existing 40-13.2 kV substation
- Installation of approximately one mile of conduit
- Installation of approximately two miles of station cable
- Installation of ten pole-top switches for station cable poles
- Installation of approximately 1.5 miles of system conduit
- Installation of approximately 4.7 miles of system cable
- Installation of six Viper reclosers
- Installation of four additional pole-top switches

More details of this project can be found in Exhibit A-23, Schedule M3.

Q120. What are the customer benefits of the Substation Risk: Sterling project?

A120. The Sterling project provides several customer benefits. The project reduces the risk of equipment-related failures by replacing aging across-the-aisle switchgear with modern PDCs equipped with supervisory control and data acquisition (SCADA) capabilities. These upgrades enhance system protection and automation, thereby reducing the frequency and duration of customer interruptions. In addition, the project will fully automate all circuits through loop schemes, automatic pole-top switches, and comprehensive fault protection. Substation capacity will be increased by approximately 54 percent, bringing distribution loading back within normal operating limits and enabling additional load-transfer and jumpering capability as needed. Collectively, these improvements will enhance system flexibility and reduce both the number and duration of outages experienced by customers.

Line No.

1 **B.10. Substation Risk: Waterman**

2 **Q121. Why was the Substation Risk: Waterman project created?**

3 **A121.** The Waterman project was initiated to address critical issues with DC grounds on a
4 NERC (North American Electric Reliability Corporation) battery at Waterman
5 substation. The DC ground on the battery could not be repaired due to the
6 inaccessibility of grounded cables embedded in the concrete walls of the substation, an
7 earlier design that is no longer used. These DC grounds jeopardized the reliability of
8 protective equipment, hindering their proper operation. In order to comply with NERC
9 Standard PRC-005 (Protection System, Automatic Reclosing, and Sudden Pressure
10 Relaying Maintenance), which mandates corrective action for systems with DC
11 grounds, the Company initiated this project.

12

13 **Q122. What is the scope of the Substation Risk: Waterman project?**

14 **A122.** The scope of the Substation Risk: Waterman project is to:

15 - Remove existing failed DC cables from (38) breaker positions
16 - Install cable trays for DC cable
17 - Install DC cables to (38) breaker positions
18 - Consolidate electrical buses to optimize space for breaker positions

19 More details of this project can be found in Exhibit A-23, Schedule M3.

20

21 **Q123. What are the benefits of the Substation Risk: Waterman project?**

22 **A123.** The Waterman project offers several benefits. By addressing the critical issue of DC
23 grounds on a NERC battery, the project maintains the safety and reliability of the
24 protective equipment, maintaining operation during fault conditions. Upgrading the DC
25 system and relocating all DC cables onto accessible cable trays will facilitate easier

Line No.

maintenance and future inspections, reducing downtime and operational disruptions. Additionally, by abandoning the grounded cables and installing new DC cables, the project mitigates the risk of potential failures, improves overall system resilience, and maintains compliance with the NERC PRC-005 standard.

X. System Equipment Replacement Program

Q124. What is System Equipment Replacement?

A124. The system equipment covered in this program is a subset of equipment critical to grid integrity, and which is not replaced in other programs, such as the PTMM and 4.8kV Hardening Programs. System equipment, including substation equipment, overhead equipment, and underground equipment, play a vital role in delivering electricity to customers, isolating and locating faults, and maintaining proper voltages and power quality on the Company's electric system. For the grid to operate reliably, this critical system equipment not only needs to be in good working condition but also needs to be able to withstand stresses from the expected system faults. Therefore, the Company routinely monitors system equipment to maintain effective operation, and if it is not operating effectively, replaces it pursuant to the System Equipment Replacement program.

Q125. How does the Company monitor and prioritize System Equipment Replacements?

A125. DTE Electric uses an asset health analysis to routinely monitor and prioritize investments in the System Equipment Replacement program and identify the equipment that requires replacement. The life expectancy of system equipment is based on a combination of manufacturer recommendations, industry benchmarks, Electric Power Research Institute ("EPRI") Industry Database, National Electric Energy

Line No.

1 Testing, Research & Applications Center ("NEETRAC") Asset Survival Plots, and
2 DTE Electric's experience. The purpose of the asset health assessments is to gather
3 information related to the Company's assets and proactively address any identified
4 equipment issues.
5
6 While age of equipment is not the only factor the Company considers when performing
7 a health assessment, it can become a significant factor when replacement parts become
8 unavailable or in the specific cases where asset health deteriorates sharply with age.
9 Other factors such as manufacturer or equipment types that have known issues and
10 elevated failure rates are also considered.
11
12 The result of the Company's asset health analysis is a ranking or score for the
13 equipment and assessment results are grouped into four categories of failure potential:
14 acceptable, elevated, high, and severe. Equipment with a "severe" asset health
15 assessment ranking is at the highest probability of failure and must be replaced in the
16 near-term to maintain safe and reliable operation.
17
18 Table 8 below shows the current replacement rates for assets near the end of life for
19 established programs:
20

Line No.

1 **Table 8 - System Equipment Replacement Rates**

Program	Units near end-of-life	Annual Units Replaced	Replacement Rate (years)
System Cable	1,610 miles	7 miles	230
URD Cable	2,611 miles	54 miles	48
Breakers	3,660	33	111

2

3 **Q126. Did the Audit Report include a recommendation related to System Equipment**
4 **Replacement?**

5 **A126.** Yes, the Audit Report, while supportive of investments in this equipment,
6 recommended the Company "[r]eplan and prioritize System Equipment Replacement
7 investments to extend their completion by five years."[44] In the final Order in the
8 proceeding, the "Commission generally agrees with Liberty's recommendation"
9 regarding this program.[45]

10

11 **Q127. How would the Audit Report recommendation impact the Company's existing**
12 **plan for the completion of System Equipment Replacements?**

13 **A127.** First, the Company's existing plan for System Equipment Replacement consists of
14 standard asset replacement required to renew the electrical infrastructure over the
15 course of time, meaning there is no "completion" to the replacements in this program.
16 Moreover, while there are System Equipment Replacements as part of the current
17 Distribution System Plan (DSP) for system cable, breakers, and Underground
18 Residential Distribution (URD) proposed in the five-year horizon due to their "severe"

[44] Case No. U-21305; Audit Report, Part Two, Chapter 1, p. 77.
[45] Case No. U-21305 Order dated June 12, 2025, p. 26

Line No.

1 asset health assessment ranking, those replacements are just a small fraction of the
2 overall need on the system. As I explained earlier in my testimony, System Equipment
3 plays a vital role in delivering electricity to customers, isolating and locating faults, and
4 maintaining proper voltages and power quality on the Company's electric system. For
5 the grid to operate reliably, this critical system equipment not only needs to be in good
6 working condition but also needs to be able to withstand the stresses from the inevitable
7 system faults. For these reasons, the Company respectfully disagrees with the Audit
8 Report's recommendation to extend "completion" of those investments by five years.

9 **Q128. What are the potential risks and consequences of extending the completion of the**
10 **System Equipment Replacement by five years as recommended in the Audit**
11 **Report?**

12 **A128.** Risk of major events increases with older, at-risk equipment and is greatest when there
13 is a combination of at-risk assets within the same substation. At-risk equipment failure
14 can also prevent load transfers. The consequences of older equipment is less grid
15 reliability and longer downtimes. The replacements proposed in the 5-year horizon of
16 the current DTE Electric DGP for system cable, breakers, and URD are just a small
17 fraction of the overall need on the Company's system. As shown in Table 8, the current
18 investment levels result in an extremely long replacement rate, ranging from 48 to 230
19 years. This effectively results in some of this equipment running to failure, versus
20 proactive planned replacement. Further extending equipment replacements by five
21 years increases the potential risk of equipment failures, causing the Company to be
22 reactive rather than proactive and the audit recommendation will only prevent the
23 Company from gaining traction towards proactive equipment replacements. Major risk
24 evaluation considers the likelihood and impact of the complete loss of a substation,

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which can impact a significant number of customers (thousands) for an extended duration (a couple of days). Over the last several years, DTE Electric has experienced an increasing number of major events on the system. In addition to the outages caused by the initial event, the outages are often extended due to a lack of system capacity at times in some areas. Replacement of at-risk equipment provides risk reduction by reducing the probability of failure of key distribution equipment.

Q129. What programs are included under System Equipment Replacement?

A129. System Equipment Replacement is divided between substation equipment, overhead equipment, underground system investments, and station upgrades and the specific programs within each division are outlined below.

A. Substation Equipment Investments

Q130. What programs are included as part of Substation System Equipment Replacement?

A130. There are four programs included as part of Substation System Equipment Replacement: (1) batteries and chargers replacement program; (2) breaker replacement program; (3) disconnect and switcher replacement program; and (4) substation regulator replacement program, all of which are discussed further below.

A.1. Batteries and Chargers Replacement Program

Q131. What are Batteries and Chargers?

A131. The Company's substations utilize batteries and chargers to provide reliable power necessary to trip equipment such as breakers during fault conditions. Failures of batteries and chargers would result in significantly longer duration faults, and therefore

greater damage to system equipment, larger outages, and increased hazards due to the inability to clear electrical faults.

Q132. Why does the Company require proactive battery replacements?

A132. Batteries and chargers have a finite lifespan and eventually require replacement with new units. The Company identifies batteries and chargers that are at-risk of failure and at end of useful life and selects them for replacement. These devices maintain substation equipment protection during fault conditions so that substation equipment can continue to operate properly to maintain reliability.

Q133. How many Batteries and Chargers does the Company plan to replace in this instant case?

A133. In 2025, the Company replaced 82 batteries and chargers. The Company plans to replace 80 batteries and chargers in 2026, 75 batteries and chargers in 2027, and approximately 12 batteries and chargers during the portion of 2028 included in the projected test year.

A.2. Breaker Replacement Program

Q134. What are substation breakers and substation reclosers, and what purpose do they serve?

A134. The path electricity travels across the system can be subjected to interruptions due to a variety of factors (*e.g.*, a tree falling on an overhead electrical line), which can cause outages and potentially dangerous situations for customers and employees. Electrical switches, most commonly breakers or reclosers, are in place at points along the network to recognize and isolate these interruptions (also known as electrical faults) from the

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rest of the distribution system. These switches help to minimize equipment damage from electrical faults and allow power to continue flowing to as many customers as possible while restoration and repair is completed for the damaged portions of circuits.

At the subtransmission and distribution levels, there are large breakers (switches) at stations and substations that interrupt the current flow when a fault is detected to minimize equipment damage and isolate the faulted equipment from the rest of the system. When a substation breaker fails, it can cause outages to several downstream circuits, often impacting several hundred customers. These breakers can also fail catastrophically, with a large flash of energy that is a significant safety risk to substation employees, and in some cases have resulted in fires and loss of oil to the environment.

Downstream from the substation breakers, located on distribution circuits, are substation reclosers. Substation reclosers perform similarly to a breaker. When they detect faults, they open and isolate the interruption to a smaller area, impacting fewer customers. Substation reclosers can prevent the substation breaker from opening, avoiding a larger circuit level outage. Additionally, these reclosers can be used to tie two circuits together so that, in the event of an outage, one circuit can provide power to the other if adequate capacity is available. Reclosers have a key role to play in improving reliability and are the foundation of the automation program, as further described by witness Rademacher.

Q135. What is included in the Breaker Replacement program?

A135. The Company has approximately 6,000 breakers on the electrical distribution and subtransmission systems with approximately 60% of those breakers at an age beyond

Line No.

1 their life expectancy. The breakers included in the replacement program have an older,
2 now obsolete design, typically utilizing insulation oil[46] for fault extinguishing. As these
3 oil-filled breakers age, the risk of failure increases. In the event of a failure, insulating
4 oil can contribute to fire hazards and may result in environmental impacts if oil is
5 released.

6 Substation breakers replaced by the Breaker Replacement program are classified into
7 four categories: (1) distribution breakers, (2) subtransmission breakers, (3) H-breakers,
8 and (4) substation reclosers. In addition to replacing breakers, the program also
9 replaces relays and controls to make the equipment Supervisory Control and Data
10 Acquisition ("SCADA")-ready. SCADA-ready equipment provides the Electric
11 System Operations Center ("ESOC") greater system performance visibility, which will
12 allow ESOC personnel to remotely reconfigure the grid to restore customers by
13 isolating faults and/or transferring load to adjacent circuits during both planned and
14 unplanned outages.
15
16 **Q136. Was the Breaker Replacement program discussed in the prior electric rate cases?**
17 **A136.** Yes, the Company's Breaker Replacement program was included in Case Nos. U-
18 20162, U-20561, U-20836, U-21297, U-21534, and U-21860.
19
20 **Q137. What has the Commission previously concluded regarding the Breaker**
21 **Replacement program investments?**
22 **A137.** Most recently, the Commission concluded in its Order for Case No. U-21534:

[46] This oil poses both a safety risk, as it can fuel fires, and an environmental risk should it leak or spill.

Line No.

> The Commission finds DTE Electric's requested capital expenditures for its Breaker Replacement program in this case to be reasonable and prudent. As stated by the company, "[b]reaker replacement is a prerequisite infrastructure investment . . . that is foundational for the continuity of electric service," with benefits of the program specifically including "enhanced safety, reduction of substation outage risk caused by breaker failures, improved customer reliability, reduction in reactive expenditures due to breaker failures, added ability to utilize SCADA controls, and the reduction of outage duration due to enhanced fault location and event analysis provided by SCADA capability."[47]

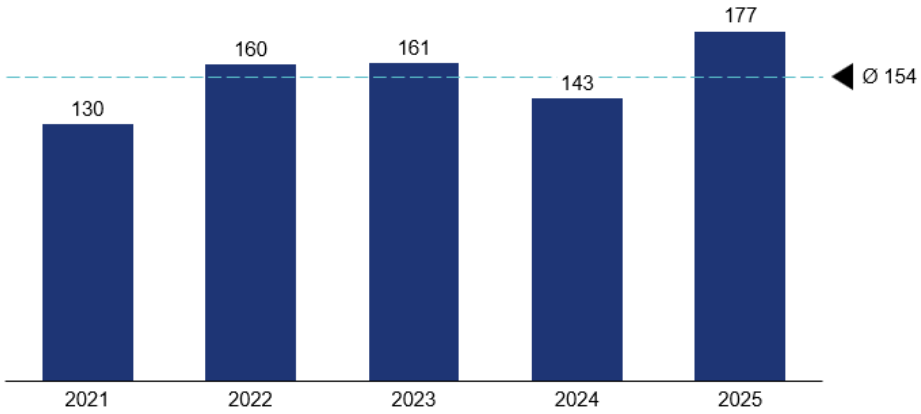
Q138. What are the customer benefits from the Breaker Replacement program?

A138. The benefits of breaker replacement and enhanced relaying and controls include enhanced safety, reduction of substation outage risk caused by breaker failures, improved customer reliability, reduction in reactive expenditures due to breaker failures, added ability to utilize SCADA controls, and the reduction of outage duration due to enhanced fault location and event analysis provided by SCADA capability. To maintain and enhance these benefits, the Breaker Replacement program seeks to systematically replace those breakers with known issues or that are otherwise likely to fail in the near future. Recent breaker failures are summarized in Figure 8 below.

[47] Case No. U-21534 Order dated January 23, 2025, p. 114-115.

Line No.

1 **Figure 8. Breaker Failures 2021-2025**



2

3 **Q139. What are the BCA analysis results for the Breaker Replacement program?**

4 **A139.** Breaker Replacement investments were evaluated at a circuit level using the BCA
5 framework described in Witness De Stigter's Exhibit A-28, Schedule R3 Revised. The
6 BCA results indicate favorable cost-effectiveness for a substantial portion of the
7 circuits analyzed. These quantitative results are supplemented by qualitative
8 considerations related to operational and safety improvements. Additional detail on the
9 BCA methodology and results is provided in Exhibit A-28, Schedule R3 Revised,
10 section 5.3.

11

12 **Q140. How are breakers selected for replacement?**

13 **A140.** The candidates for breaker replacements are prioritized by the Company's equipment
14 engineers based on the following criteria: breakers with known performance issues;
15 breakers with no or limited availability of spare parts; breakers with insulation oil for
16 fault interrupting medium which is flammable; and breakers that require short
17 inspection cycles compared to the rest of the breakers on the Company's system.

Line No.

Q141. Can you provide a specific example of an obsolete breaker type that is prioritized for replacement by the Breaker Replacement program?

A141. Yes. H-breakers are an obsolete oil-filled breaker design, amongst the oldest in the utility industry, dating back to at least the 1920s. H-breakers are no longer manufactured, and replacement parts are not available in the market for them. As stated above, these breakers can also fail catastrophically, with a large flash of energy that is a significant safety risk to substation employees, and in some cases have resulted in fires and loss of oil to the environment.

Q142. How many Breakers have been replaced through the Breaker Replacement program between 2021 and 2025?

A142. Between 2021 and 2025, the Breaker Replacement program replaced a total of 167 breakers. Included in the replacements were Distribution Breakers, Substation Breakers, H-Breakers and Substation Reclosers. Please see Table 9 for more details.

Table 9 - Breakers Replaced 2021-2025

Breaker Type	2021	2022	2023	2024	2025
Distribution Breakers	22	15	16	16	13
Subtransmission Breakers	4	12	6	8	3
H-Breakers	3	2	3	2	0
Substation Reclosers	10	5	4	10	13
Total Breakers	**39**	**34**	**29**	**36**	**29**

Line No.

1 **Q143. Are any Breaker Replacement investments included in the proposed**
2 **Infrastructure Recovery Mechanism (IRM)?**
3 **A143.** Yes. As described by Witness Chiu, the Company is proposing to recover Breaker
4 Replacement investments through the IRM. Investments are partitioned between
5 recovery through base rates, as proposed in Exhibit A-12, Schedule B5.4 Revised, and
6 the Company's authorized IRM mechanism, in Exhibit A-33, Schedule X1.
7
8 **Table 10 - Proposed Breaker Replacement Investments (in millions)**

	2025	2026	2027	2028
Base Rates	(.3)	-	-	3.3
IRM	12.6	12.6	15.0	16.7
Total	**12.3**	**12.6**	**15.0**	**20.0**

9
10 Breaker Replacement investments beyond the test year, as described below, are
11 proposed for inclusion in the IRM and shown in Exhibit A-33 Schedule X1. Witness
12 Chiu discusses the background of the IRM and supports the inclusion of investments
13 in the IRM.
14
15 **Q144. What are the Company's expectations for investment in Breaker Replacements**
16 **beyond the projected test year?**
17 **A144.** The Company will need to continue investing in Breaker Replacements beyond the
18 projected test period covered in this case. The forecast of required investment on a
19 calendar year basis beyond the test year is:

Line No.

- 2028: $16.7 million
- 2029: $35.0 million
- 2030: $55.0 million

This reflects the full expected capital investment for the program from beyond the test year (March 1, 2028) to 2030 and is included in this case as the basis for the Company's IRM request supported by Witness Chiu. The first two months of 2028 are part of the projected text year and are therefore reflected on Exhibit A-12, Schedule B5.4 Revised.

A.3. Disconnect and Switcher Replacement

Q145. What are Disconnects and Switchers?

A145. Subtransmission disconnect switches ("disconnects") are used to sectionalize and provide isolation points on the electrical system for operational reasons and to enable service and maintenance. Failures of disconnects during operation, when operators attempt to open or close a disconnect manually, can lead to safety concerns, reduce system operability, and force additional equipment to be taken out of service to allow critical work to continue.

Circuit switchers ("Switchers") connect the transmission system (generally 120kV) and the subtransmission system (generally 40kV) to the primary side of a substation power transformer. The purpose of circuit switchers is to protect substation equipment from damage caused by excess fault current. Circuit switchers are a smaller, less expensive alternative to circuit breakers. The Company uses circuit switchers primarily for transformer protection in new construction. Circuit breakers, however, are used instead

when specific requirements, such as the need for reclosing functions or handling high fault currents, exceed the capacity of the circuit switchers.

Q146. How does the Disconnects and Switchers program benefit customers?

A146. The Company replaces disconnects and switchers that have been identified by engineers as at-risk or have been identified as being undersized compared to the current fault currents, making them no longer capable of providing proper protection to transformers. These replacements help to protect the Company's operators while manually operating the equipment, allow the Company to sectionalize the system (thus reducing the size and impact of customer outages) when performing work, and to protect the other substation equipment from damage when excess fault current occurs.

Q147. How many disconnects and switchers is the Company planning to replace in this instant case?

A147. In 2025, the Company replaced 15 disconnects and 4 switchers. The Company plans to replace 12 disconnects and 3 switchers in 2026. In the projected test year, the Company plans to replace 12 disconnects and 4 switchers.

A.4. Substation Regulator Replacement

Q148. What are Substation Regulators?

A148. Substation regulators are devices that are designed to maintain voltages within the normal ranges for which Company and customer equipment is rated to perform. Voltage regulation is critical to maintaining system voltages within specified ranges, so that customers do not experience the negative effects of high or low voltage in their homes and businesses. Voltage regulation is also critical to maintaining the health of

downstream grid electrical equipment and helps to maintain the service life of this equipment.

Q149. How does replacing Substation Regulators benefit customers?

A149. In addition to the customer impacts of voltage that is too high or low, voltage regulation is essential to maintain the health and operability of electrical equipment and prevents the premature damage and failure of this equipment, thus reducing outages customers experience as well as replacement of equipment.

Q150. How many Substation Regulators does the Company plan to replace in this instant case?

A150. In 2025, the Company replaced 2 substation regulators. The Company plans to replace 2 substation regulators in both 2026 and 2027, representing approximately 1.5% of the total population of substation regulators for both years. The replacement cost is approximately $410 thousand per substation regulator. As mentioned later in my testimony, Table 20 – 22 in Preventative Maintenance Activities – Substation, the population of substation regulators is 249.

B. Overhead Equipment Investments

Q151. What programs are included as part of Overhead Equipment Investments in System Equipment Replacement?

A151. There are three categories included as part of Overhead Equipment Investments in System Equipment Replacement: (1) 40kV: automatic pole-top switches, (2) SCADA pole-top device replacement, and (3) steel pole highway crossings, all of which are discussed further below.

Line No.

1 **B.1. 40kV: Automatic Pole-Top Switch**

2 **Q152. What are Automatic Pole-Top Switches ("APTS")?**

3 **A152.** APTS are devices used on the subtransmission system to sectionalize, isolate, or
4 connect portions of the system to support normal operations and facilitate restoration
5 during outage conditions. When operating as designed, APTS enable operators to
6 isolate faulted sections of the system and restore service to affected customers more
7 quickly.

8

9 The Company has identified certain APTS currently installed on the subtransmission
10 system that are inoperable or operating in a degraded state, as well as devices for which
11 replacement parts are no longer available due to obsolescence. While some of these
12 switches may remain in a fixed or default position and therefore do not immediately
13 interrupt service, their degraded condition reduces operational flexibility and limits the
14 Company's ability to sectionalize the system during abnormal conditions.

15

16 A failure of an APTS under load or during a system disturbance, or the inability of the
17 switch to operate when required, has the potential to interrupt service to a large number
18 of customers or result in significant operational constraints. In recent years, the failure
19 rate of these switches has been increasing, ranging from 15 to 20 percent. Accordingly,
20 replacement of obsolete or degraded APTS is intended to restore intended functionality,
21 reduce operational risk, and mitigate the potential for widespread customer impacts.

22

23 **Q153. How does the 40kV: APTS program benefit customers?**

24 **A153.** As discussed above, APTS are critical to isolating faulted sections of the system and
25 restoring service during outage conditions. When an APTS is inoperable, operating in

Line No.

a degraded condition, or unable to function when required, the Company's ability to sectionalize the system is reduced, which can result in extended outages affecting a large number of customers.

The Company has identified APTS currently installed on the system that are inoperable, operating in a degraded state, or obsolete due to the unavailability of replacement parts. While some of these devices may not cause an immediate outage under normal conditions, their degraded condition limits operational flexibility and increases the risk that, during a fault or abnormal system event, outages will last longer or affect more customers than would otherwise be necessary.

The 40 kV APTS program benefits customers by replacing degraded and obsolete devices, restoring intended functionality, and ensuring that APTS operate as designed when needed. These improvements reduce outage duration, limit the number of customers affected by outages, and improve overall system reliability.

Q154. How many APTS is the Company planning to replace in the instant case?

A154. In 2025, the Company replaced 13 APTS. The Company plans to replace approximately 13 APTS in the bridge period and approximately 14 in the projected test year. The Company has total population of 144 APTS on the subtransmission system.

B.2. SCADA Pole-Top Device Replacement

Q155. What are SCADA Pole-Top Devices?

A155. SCADA-enabled pole-top devices, such as overhead three-phase reclosers, are grid sectionalizing devices that are located at key points on overhead distribution circuits.

These devices act like a circuit breaker, opening under detection of high current due to a downstream fault, such as a tree branch across two phases. As I explained above, these devices allow the ESOC to remotely reconfigure the grid to restore customers by isolating faults and/or transferring load to adjacent circuits with available capacity during both planned and unplanned outages.

Q156. How does replacing SCADA Pole-Top Devices benefit customers?

A156. This program replaces specific groups of devices that have experienced high rates of failure such as Eaton Form 3 reclosers and Bridges pole-top switches ("PTS"). Failure of these devices reduces system operability, thus increasing the amount of extended duration outages for customers. Replacing these identified devices allows the ESOC to operate the system more effectively, thereby reducing the number and duration of outages experienced by customers.

Q157. How many SCADA Pole-Top Devices does the Company plan to replace in this instant case?

A157. In 2025, the Company replaced 20 SCADA pole-top devices. The Company plans to replace 20 SCADA pole-top devices in the bridge period. In the projected test year, the Company plans to replace 23 SCADA pole-top devices.

B.3. Steel Pole Highway Crossings Program

Q158. What is the Steel Pole Highway Crossings program?

A158. The Company has experienced incidents where wood poles have failed, resulting in wires falling onto highways and causing road closures. In addition to the reliability impact of a downed wire, the wires that cross highways and fail have added safety risk

Line No.

as well as the impact to the public of highway closures. To address these incidents, the Steel Pole Highway Crossing program identifies current wood pole locations where the overhead wire crosses a highway and has a high risk of failure and replaces these at-risk wood poles with steel poles to reduce the likelihood of pole failures that can impact traffic and public safety and cause customer outages.

Q159. How does the Steel Pole Highway Crossings program benefit customers?

A159. While the program was developed to replace meaningful-risk wood poles with steel poles to reduce the risk of overhead equipment falling and disrupting the highway system, it also provides an associated reliability benefit, as failed poles can result in customer outages.

Q160. How many Steel Pole Highway Crossings does the Company plan to complete in this instant case?

A160. In 2025, the Company installed one Steel Pole Highway Crossing and plans to complete 1 crossing in as part of the bridge year. In the projected test year, the Company plans to replace 2 crossing.

C. Underground System Investments

Q161. What programs are included as part of Underground ("UG") System Investments in System Equipment Replacement?

A161. There are two programs included as part of Underground System Investment in System Equipment Replacement: (1) the system cable replacement program and (2) the underground residential distribution (URD) program, both of which are discussed further below.

Line No.

C.1. System Cable Replacement Program

Q162. What is System Cable, and how is it different from URD Cable?

A162. System cable is a specific type of cable designed and used for underground distribution and subtransmission on the Company's primary electric system. System cable consists of large diameter cable surrounded by various types of insulation, and it is installed underground in vaults and ducts that runs between manholes.

System cable is used for a different purpose than URD cable. System cable is used to transmit higher voltage electricity from substation to substation and to feed primary circuits, and supports a large number of customers, while URD cable is designed to provide lower voltage electricity directly to and within residential neighborhoods, supporting a relatively smaller number of customers. URD is discussed in more detail later in my direct testimony.

Q163. What are the key drivers of the Company's System Cable Replacement program?

A163. System cable is a critical component of the distribution and subtransmission systems. While system cable provides high resiliency to storms, system cable failures do happen and can interrupt a large number of customers for an extended period of time due to the longer amount of time it typically takes to locate and replace a failed cable. System cable is also installed in an underground system of manholes and conduits, often in or adjacent to roads, making access more challenging. In addition to road traffic to manage, the manholes can experience structural failures and flooding, and the conduits also experience structural challenges that can prevent access and removal. System cable replacement is an industry standard program to reduce system risk and support reliability.

Line No.

When a system cable fails, the customers fed from that circuit are typically switched to a redundant, or back-up cable, to restore power, and remain on the alternate circuit until the original cable is replaced and back in service. The process to replace the cable includes work underground locating the fault, de-energizing the circuit, cutting the failed section(s), pulling the failed cable out of the conduit, installing new cable, reconnecting (splicing) the new cable to the existing circuit, and re-energizing the circuit. During the time it takes to find and repair the cable, in addition to the directly caused outages, the system has lost redundancy and has increased risk for longer duration outages, which can happen when a failure occurs on the redundant circuit. Some customers, such as hospitals, have policies of limiting services such as surgeries during events where backup power is not available. System cable failures can also cause failures in other equipment, including adjacent cables and switchgear, which can then impact an even larger number of customers for a longer period of time. The Company has had an average of 224 system cable failures per year over the last five years (Table 11).

Line No.

1 **Table 11 - System Cable Failures by Cable Type and Year**

Failures by Cable Type	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Actual
PILC	180	202	171	144	175
VCL	5	8	16	13	1
Gas	3	3	12	3	7
XLPE Pre-1990	5	1	16	9	3
XLPE Post-1990	-	-	-	-	-
EPR	17	24	37	28	27
Butyl Rubber	3	2	3	1	1
Total Cable Failures	**213**	**240**	**255**	**198**	**214**

PILC: system cable that is insulated with paper and lead
EPR: system cable that is insulated with ethylene propylene rubber
VCL: system cable insulated with varnished cambric
Gas: system cable that is insulated with nitrogen gas under pressure
XLPE: system cable that is insulated with cross-linked polyethylene
Butyl Rubber: system cable that is insulated with butyl rubber

2 During system cable emergent restoration, the crews may experience multiple
3 challenges including safety risk, which can complicate the work or slow progress on
4 remediation of the failure. In some instances, field crews find underground ducts have
5 collapsed on the cables, making the cable extremely difficult, or in some cases
6 impossible to replace without repairing the ducts (Figure 9). Safety concerns during
7 restoration sometimes cause other intact cables near the failed cable to require a
8 shutdown, meaning they must be de-energized from the substation to make the site safe
9 for work.

Line
No.

1 **Figure 9. System Cable – UG Collapsed Duct**

2

3 Other examples of safety and logistical concerns include the need to pump water out of
4 the manholes (Figure 10) before work can begin and environmental management of the
5 wastewater, the need to follow safety protocols including ensuring the air quality is
6 safe for entry in what is designed as a confined space and often including remediation
7 of contaminants such as lead and asbestos. Once the manholes can be entered safely,
8 the work includes inspecting and testing long stretches of cable to find the fault, and
9 identification of adjacent hazards. Finally, the crews typically pull and splice the cable
10 as described above, which can be difficult during an emergent failure and restoration
11 situation. In addition to safety inside the manholes, the crews above and below ground
12 face challenges of traffic, as the manholes are often located in streets, and require lane
13 closures.

Line No.

1 **Figure 10. System Cable – Cable Inside Manhole**

2

3 In addition to general concerns that are related to age, some types of cables are known
4 to have specific failure modes. As an example, XLPE (cross-linked polyethylene)
5 system cable manufactured before 1990 has a design defect that leads to premature
6 insulation breakdown and failures (also called "treeing"), a condition that has
7 contributed to switchgear failures. As another example, gas cable, designed to have
8 cavities within the insulating layer that are filled with nitrogen gas under pressure, is
9 an obsolete design, prone to mechanical damage that leads to leaks and failures, as well
10 as costly repairs. As detailed in the DSP (as supported by Witness Chiu), approximately
11 52% of the Company's system cable is at or beyond useful life expectancy.[48] Useful
12 life is a standard industry term that does not represent the actual life of an asset, but
13 rather the age at which an installed asset is expected to require increasing maintenance
14 and reduced performance such that it is often more prudent to replace than to continue

[48] Exhibit A-23, Schedule M1, Section 4.2.3

Line No.

to repair and maintain. While age is not the only factor used by engineers to determine a need for replacement, in the Company's experience, failure rates increase with age as older cable has typically been exposed to more fault currents over time and has had longer water exposure.

Table 12 shows the average age of the different types of the approximately 3,100 miles of system cable that are within the scope of the Cable Replacement program. The typical useful life expectancy of system cable is 35 to 40 years, although actual useful life varies depending on cable type and field conditions. Based on the engineering asset health assessment for system cable, the Company has determined that approximately 28% of its system cable is considered at-risk cable and a candidate for replacement, including XLPE cable manufactured before 1990, gas cable, VCL (varnished cambric lead), and paper-insulated-lead cable (PILC) cable greater than 60 years in age.

Table 12 - System Cable Types - Average Age and Life Expectancy

Cable Type	PILC	EPR	VCL	Gas	XLPE Pre-1990	XLPE Post-1990	Butyl
Miles	2,069	748	95	47	58	48	31
% of Total Population	66.8%	24.2%	3.1%	1.5%	1.9%	1.5%	1.0%
Average Age	55	18	64	59	40	23	57
Useful Life Expectancy	40	35	40	40	25	40	25

Line No.

Planned replacement of UG system cable allows the Company to proactively target cable at high risk of failure. This allows for a more strategic, and more efficient process to replace large portions of cable in order to reduce the risk of failures and increase redundancies in a given area.

Q164. What is the scope of the System Cable Replacement program?

A164. The System Cable Replacement program identifies and replaces at-risk system cable. System cable replacement prioritization is based on multiple factors including insulation type, failure history, system impacts, and cable loading. These cables are installed in conduit and spliced together in manholes. When replacing system cable, the Company will also replace failed/collapsed conduit, ducts, and manholes, upgrade substation cable positions, and rebuild cable poles, as necessary.

As part of the System Cable Replacement program, the Company also implements the System Cable Testing program. A comprehensive System Cable Testing program is essential to maintain and improve the reliability and safety of the electrical infrastructure. Regular testing helps identify potential issues before they lead to failures and reduces the risk of unexpected outages. This proactive approach ultimately leads to a reduction in reactive cost and improved reliability for customers.

The Company developed the testing program with a structured approach while also emphasizing efficiency and cost management. Specifically, the program aims to start with 40 circuits tested in 2026, increasing the circuits tested each year. The cost per circuit generally ranges from $25,000 to $50,000, which includes fully loaded labor costs for planning, pre-and post-switching of load, and actual testing of the circuit.

Line No.

1 Utilizing this structured approach, the Company's forecasted expense request and
2 number of circuits tested each year are as follows:

3 • 2026: Request: $2,000,000; Circuits: 40-80
4 • 2027: Request: $3,000,000; Circuits: 60-120; and
5 • 2028: Request: $4,000,000; Circuits: 80-160.

6 The costs associated with the System Cable Testing program are O&M expenses that
7 appear in Exhibit A-13 Schedule C5.6 Revised p.2.
8
9 **Q165. What did the Commission state with respect to the System Cable Replacement**
10 **program in past rate cases?**
11 **A165.** The Commission stated in its Order in Case No. U-21534:
12
13 > The Commission finds DTE Electric's requested capital expenditures
14 > for its System Cable Replacement and URD Replacement programs to
15 > be reasonable and prudent. As stated by the company, system cable and
16 > URD cable replacement efforts benefit customers by prioritizing and
17 > proactively replacing cables and transformers to reduce the risk of
18 > failures and prolonged outages, thereby supporting continued
19 > reliability.[49]
20
21 In Case No. U-21860, the Commission did not adopt "the ALJ's recommendation to
22 include the small wire replacement program in the 2026 IRM and further declines to
23 adopt DTE Electric's proposal to include system cable in the extended IRM."[50]

[49] Case No. U-21534 Order dated January 23, 2025, pp. 111-112
[50] Case No. U-21860 Order dated February 19, 2026, p. 385

Line No.

1 **Q166. Did the Audit Report include a conclusion and recommendation related to System**
2 **Cable?**
3 **A166.** Yes, the Audit Report concluded "DTE's subtransmission cable failure rate has been
4 too high."[51] Additionally, the Audit Report recommended the Company "[p]lan for
5 replacement of poor-performing subtransmission cable types over the long term."[52]
6
7 **Q167. How does the Audit Report recommendation impact the Company's existing plan**
8 **for completion of subtransmission cable?**
9 **A167.** The Company supports the replacement of poor-performing subtransmission cable,
10 which is a subset of system cable, but disagrees with extending the program over the
11 longer term, slowing the rate of replacement. Subtransmission cables play a vital role
12 in delivering electricity to customers and can cause prolonged outages when they fail
13 due to the complexity of reactive replacement under emergency situations, therefore,
14 the Company believes this program should continue to move forward as outlined in the
15 Distribution System Plan.[53]
16
17 **Q168. What are the potential risks and consequences of replacement of poor-performing**
18 **subtransmission cable types over a longer term?**
19 **A168.** Over the last several years, the Company has experienced an increasing number of
20 major events on the system. Delaying the replacement of subtransmission cables
21 increases risk by increasing the probability of failure of these critical assets. 52% of
22 system cable, or approximately 1,600 miles[54], is at or near the end of useful life. The
23 Company's current annual cable replacement program is a small fraction of the

[51] Case No. U-21305, 068cs00000AyaNpAAJ, Audit Report, Part Two, Chapter 1, p. 42
[52] Case No. U-21305, 068cs00000AyaNpAAJ, Audit Report, Part Two, Chapter 1, p. 44
[53] Exhibit A-23, Schedule M1, Section 4.2.3
[54] Exhibit A-23, Schedule M1, Section 4.2.3, Exhibit 4.22

Line No.

identified miles for replacement and is therefore already operating on a longer than preferred cadence. The Company replaced approximately 6 miles in 2025 and plans to replace approximately 22 miles in 2026. Based on an average replacement rate of approximately 7 miles per year over the past five years, it would take roughly 230 years to replace the 1,610 miles of at-risk system cable at the current pace. The Company is increasingly concerned about the level of failure-risk posed by the age and condition of system cable because of the impact a system cable failure has on the overall system. When system cable fails, it reduces the level of redundancy of the grid and increases the risk of long duration customer outages.

Q169. What sections of cable are replaced by the System Cable Replacement program?

A169. The System Cable Replacement program prioritizes and replaces sections of cable that are deemed at-risk based on their engineering asset health assessment as discussed above. If there are sections of cable on a circuit that are not deemed to be at-risk, they are not replaced by the program.

Q170. How much system cable was replaced in 2025 and prior years?

A170. The Company replaced approximately 4 miles of system cable in 2025 and has replaced approximately 36 miles of system cable over the last five years. Table 13 shows annual system cable miles replaced and the associated investment for the last five years.

Line No.

1 **Table 13 - System Cable Program 2021-2025**

	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Actual
Cable Miles Replaced	7	5	8	12	4
Capital Investment ($ millions)	$15.0	$27.7	$22.5	$25.6	$15.9

2

3 **Q171. How much system cable replacement is planned for the bridge period and**
4 **projected test year?**

5 **A171.** The Company plans to replace approximately 5 miles in the bridge period and 6 miles
6 in the projected test year.

7

8 **Q172. How does the System Cable Replacement program benefit customers?**

9 **A172.** Replacing at-risk system cable supports continued reliability for customers. The
10 underground cable system is designed with multiple redundancies to maintain customer
11 reliability. While single cable failures do not normally result in customer outages, if
12 the primary and redundant cables fail at the same time, it results in prolonged outages
13 for customers. Some types of industrial class customers, such as hospitals, are not able
14 to tolerate the risk of running with a single cable and therefore reduce or shut down
15 some functions when this happens. This program reduces overall risk to customers and
16 the grid by proactively replacing cables before they fail, in order to maintain necessary
17 redundancies as designed. The program also reduces safety risk, as I noted earlier in
18 my testimony.

Line No.

Q173. What are the BCA analysis results for the System Cable Replacement program?

A173. System Cable Replacement investments were evaluated at a circuit level using the BCA framework described in Witness De Stigter's Exhibit A-28, Schedule R3 Revised. The BCA results indicate favorable cost-effectiveness for a substantial portion of the circuits analyzed. These quantitative results are supplemented by qualitative considerations related to operational, customer, and safety improvements. Additional detail on the BCA methodology and results is provided in Exhibit A-28, Schedule R3 Revised, section 5.5.

Q174. What are the Company's expectations for investment in System Cable beyond the projected test year?

A174. The Company will continue to need to invest in System Cable beyond the projected test period covered in this case. The forecast of required investment on a calendar year basis beyond the test year is:

- 2028: $31 million
- 2029: $40 million
- 2030 $55 million

This reflects the full expected investment for the program from beyond the test year (March 1, 2028) to 2030 and is included in this case as the basis for the Company's IRM request supported by Witness Chiu. The first two months of 2028 are part of the projected test year and are therefore reflected on Exhibit A-12, Schedule B5.4 Revised.

Line No.

C.2. Underground Residential Distribution ("URD") Replacement program

Q175. What is URD cable, and why does the Company replace it?

A175. URD is a specific type of cable designed for underground residential use on the Company's secondary electric system, as an alternative to overhead construction. URD consists of small diameter cable surrounded by polyethylene insulation and is either directly buried into the ground or less frequently is installed inside conduit (Figure 11). URD design also includes ground level pad mounted transformers. Because underground repairs can take significant amounts of time to locate and repair when compared to overhead infrastructure, URD systems are typically looped so that there are two paths to feed customers in case one URD cable fails.

Figure 11. URD Cable – Example

As mandated by Michigan Administrative Code R. 460.512, all residential subdivisions in the Company's service territory built since January 1, 1971, are served with URD

Line No.

1 cable. There are two primary types of URD cable, differentiated by manufacture date.
2 Pre-1985 URD cable has XLPE (non-tree retardant) insulation, while post-1985 the
3 insulation has TR-XLPE (tree-retardant) insulation. In cable insulation, "treeing" refers
4 to the tree-like pattern of insulation breakdown. The breakdown typically originates at
5 an impurity or defect in the solid insulation and grows gradually over time to resemble
6 the branches of a tree, leading to a cable failure. There are approximately 11,000 total
7 miles of URD cable on the Company's system, with approximately 2,618 miles (23%)
8 being pre-1985 non-tree retardant vintage (Table 14).
9
10 **Table 14 - URD Cable Types - Average Age and Life Expectancy**

URD Type	Pre-1985	1985+
URD Cable Miles	2,618	8,736
% of Total Population	23%	77%
Average Age (Years)	45	25
Life Expectancy (Years)	40	50

11
12 In addition to failures caused by treeing described above, the rate of URD cable failures
13 typically increases with the age of the cable, and the rate further increases once a cable
14 experiences its first failure. Manufacturer expected useful life for URD cable is
15 approximately 40 years. Useful life is a standard industry term that does not represent
16 the actual life of an asset, but rather the age at which an installed asset is expected to
17 experience increasing failure rates and reduced performance such that it is often more

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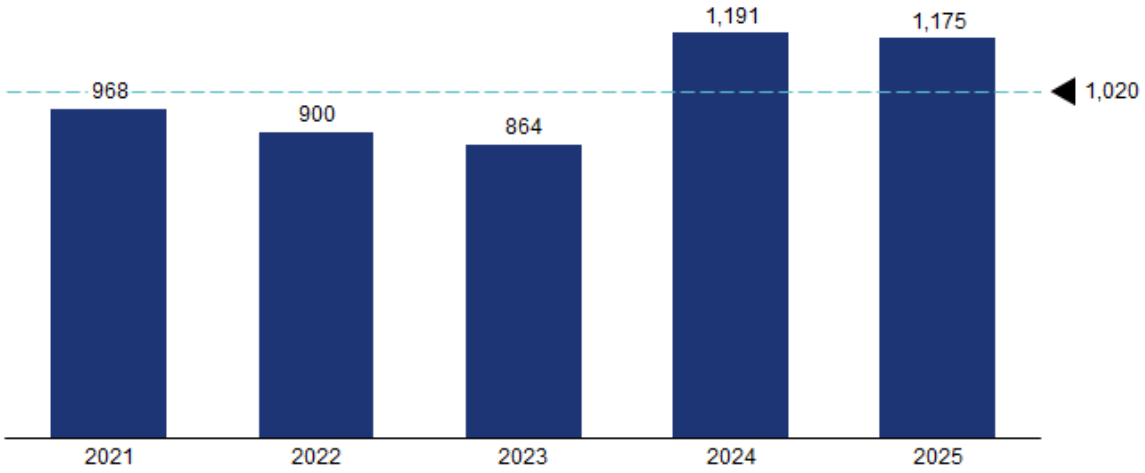
prudent to replace than to continue to repair and maintain. For the five-year period from 2021 through 2025, there were on average approximately 1,020 URD cable failures per year as seen in Figure 12.

Figure 12. URD Cable Failures



Q176. What is the scope of the URD Replacement program?

A176. There are two primary types of work performed by the URD Replacement program: (1) prioritizing and replacing existing URD cable and (2) replacing UG transformers along URD routes that present an environmental or safety risk.

The program prioritizes and replaces URD cable based on multiple factors including number of failures on the circuit, and number of customers affected by those failures, and URD cable type.

Single URD cable faults (outages) are typically restored quickly after an UG splicing crew arrives and bypasses the URD failure by back feeding the customers from another

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1 source on the URD loop. However, once the customers are restored, there is follow-up
2 work required to locate and repair the URD fault that caused the original outage, and
3 to restore the system to normal operating conditions. This follow-up work is called an
4 open loop. These open loops leave the system without redundancy, such that if a second
5 URD failure occurs on the same URD loop, a new long-duration outage (4+ hours) will
6 result for the customers as there is no redundancy to back feed the customers as
7 described above, while replacing the failed URD cable. Second URD failures within
8 six months of the original failure have occurred on average 86 times annually over the
9 last five years (Table 15).
10
11 **Table 15 - URD Double Cable Failures Within 6 months**

	2021	2022	2023	2024	2025	Avg
URD Double Cable Failures	59	32	115	125	99	**86**

12
13 As shown in Table 16, URD double-cable failure events from 2021 through 2025
14 impacted thousands of customers annually and resulted in significant customer outage
15 minutes, peaking in 2023, demonstrating that these events remain a material driver of
16 reliability risk.

Line No.

1 **Table 16 - URD Double Cable Failure Outage Data**

URD Double Failures w/in 6 months	2021	2022	2023	2024	2025
Customers Impacted	2,542	1,749	5,415	4,558	4,566
Outage Duration	370 hours	187 hours	791 hours	577 hours	364 hours
Average Outage Duration	6.3 hours	5.9 hours	6.9 hours	5.8 hours	3.6 hours
Total Customer Outage Minutes	837,078	683,363	2,574,899	1,410,736	837,344

2

3 In addition, planned replacements are more cost effective than repairing emergent
4 failures, as the Company can strategically plan to replace entire circuits of URD and
5 live-front transformers, rather than reactively fixing smaller sections of the circuit
6 following a failure.

7

8 URD Replacement Program investments include design for subsequent program years;
9 remediation of identified hazards to facilitate efficient execution of future work;
10 replacement of targeted URD cable miles; replacement of live-front transformers with
11 dead-front transformers (as shown in Figure 13); and replacement of dead-front
12 transformers that present identified safety or environmental risks. As shown in
13 Figure 13, live-front transformers expose energized components once the external
14 covering is removed, creating an elevated risk of accidental contact for field personnel
15 during operating or maintenance activities. Dead-front transformers incorporate fully
16 insulated and shielded terminations that maintain protective barriers between energized

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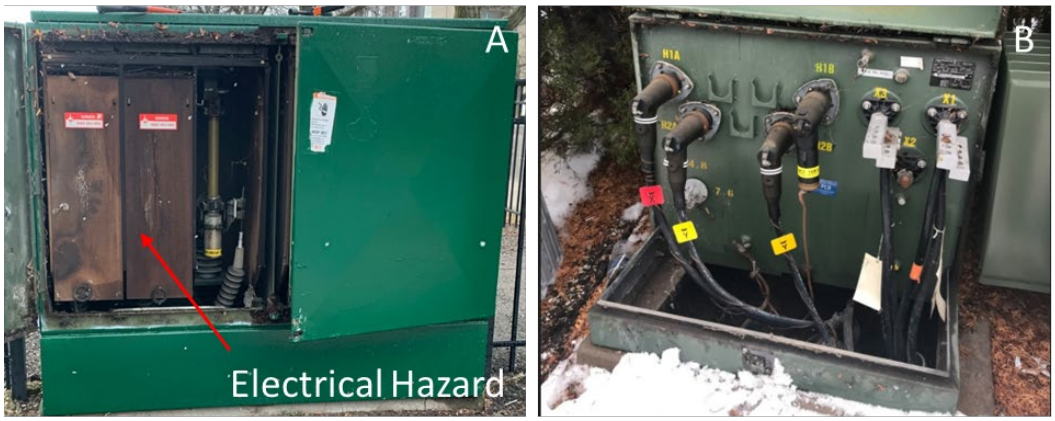
components and workers, significantly reducing safety risk and aligning with current Company design standards.

Figure 13. (A) Live-front and (B) Dead-front UG Transformer



In addition, inspections conducted during URD replacement activities have identified defective dead-front underground transformers that pose safety and environmental risks. Observed conditions include deterioration of protective barriers over energized components, resulting in exposed conductors, as well as oil leaks attributable to environmental degradation such as corrosion. Oil leakage presents both an environmental concern and an indicator of potential imminent equipment failure. Replacing defective dead-front transformers concurrently with URD cable replacement represents the most cost-effective means of addressing these safety and environmental risks by leveraging the same construction window, crews, site access, traffic control, and outage coordination required for the primary URD work. Performing the work as an integrated activity eliminates the need for separate future mobilizations to the same location, thereby avoiding unnecessary mobilization and duplicative service costs.

Line No.

1 **Q177. How does the URD Cable Replacement program benefit customers?**

2 **A177.** The program will improve reliability by reducing the number of residential customer
3 interruptions experienced by URD cable failures in the areas in which this program has
4 completed work. This will also benefit customers by reducing the risk of multiple
5 failures and long duration outages due to pre-existing open loops as described above.
6
7 The program also enhances safety by replacing obsolete live-front transformers with
8 dead-front transformers that provide insulated and shielded terminations, reducing
9 exposure to energized components during operating and maintenance activities and
10 aligning with current Company design standards. In addition, defective dead-front
11 transformers that present identified safety or environmental risks, such as degraded
12 protective barriers or oil leaks, are replaced concurrently with URD cable work.
13 Coordinating these replacements within the same construction window avoids
14 duplicative mobilization, reduces future outage risk, and represents the most
15 cost-effective approach for customers.
16
17 **Q178. What are the BCA analysis results for the URD Replacement program?**

18 **A178.** URD Replacement investments were evaluated at a circuit level using the BCA
19 framework described in Witness De Stigter's Exhibit A-28, Schedule R3 Revised. The
20 BCA results indicate favorable cost-effectiveness for a substantial portion of the
21 circuits analyzed. These quantitative results are supplemented by qualitative
22 considerations related to operational, customer, and safety improvements. Additional
23 detail on the BCA methodology and results is provided in Exhibit A-28, Schedule R3
24 Revised, section 5.4.

Line No.

Q179. Were URD Replacement Program investments addressed in prior rate cases?

A179. Yes. The URD Replacement program was included in Case Nos. U-20162, U-20561, U-20836, U-21297, U-21534, and U-21860. Most recently, in the Commission's Order in Case No. U-21860, the Commission approved funding for the URD Replacement Program and funded the program in the IRM.[55]

Q180. How much URD cable was replaced in 2025?

A180. The URD Replacement program replaced 54 miles of URD cable in 2025 and has replaced approximately 270 miles of URD cable from 2021-2025 (Table 17).

Table 17 - URD Cable Miles & Transformers Replaced 2021-2025

	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Actual
URD Miles Replaced	24.5	44.7	75.3	71.3	54.4
Live-front Transformers Replaced	63	110	111	211	69

Q181. Are any URD Replacement investments included in the Infrastructure Recovery Mechanism (IRM)?

A181. Yes. As described by Witness Chiu, the Company is proposing to recover a portion of URD Replacement investments through the IRM. Investments are partitioned between recovery through base rates, as proposed in Exhibit A-12, Schedule B5.4 Revised, and the Company's authorized IRM mechanism, in Exhibit A-33, Schedule X1.

[55] Case No. U-21860 Order dated February 19, 2026, p. 386

Line No.

1 **Table 18 - Proposed URD Investment (in millions)**

	2025	2026	2027	2028
Base Rates	.8	-	-	3.3
IRM	13.5	13.5	15.0	16.7
Total	**14.3**	**13.5**	**15.0**	**20.0**

2

3 URD Replacement investments beyond the test year, as described below, are proposed
4 for inclusion in the IRM and shown in Exhibit A-33 Schedule X1. Witness Chiu
5 discusses the background of the IRM and supports the inclusion of investments in the
6 IRM.

7

8 **Q182. What are the Company's expectations for investment in URD Replacement**
9 **beyond the projected test year?**

10 **A182.** The Company will continue to need to invest in these programs beyond the projected
11 test period covered in this case. The forecast of required investment on a calendar year
12 basis beyond the test year is:

13 - 2028: $16.7 million
14 - 2029: $35 million
15 - 2030: $55 million

16

17 This reflects the full expected capital investment for the URD Replacement program
18 from test year (March 1, 2028) to 2030 and is included in this case as the basis for the
19 Company's IRM request supported by Witness Chiu. The first two months of 2028 are

1 part of the projected test year and are therefore reflected on Exhibit A-12, Schedule
2 B5.4 Revised.
3
4 **D. Station Upgrade Projects**
5 **Q183. What are Station Upgrade projects?**
6 **A183.** In addition to substation risk projects, the Company has a group of investments that are
7 called Station Upgrade Projects. Station Upgrade Projects are designed to enhance the
8 safety and reliability of the electric subtransmission and distribution system by
9 upgrading key infrastructure at DTE Electric stations and improving relay systems at
10 points of interconnection with the International Transmission Company (ITC). The
11 projects also focus on reducing reactive costs and delivering a more reliable and
12 resilient electric grid.
13
14 **Q184. What Station Upgrade projects are part of this proceeding?**
15 **A184.** There are two station risk upgrade projects that are part of the current proceeding. The
16 projects include: (1) 120kV Relay Upgrades in coordination with ITC Projects and (2)
17 Navarre station project. These projects are scheduled to be completed between 2026
18 and 2028 and will involve upgrades to replace breakers and the associated relay panels
19 and enable advanced SCADA capabilities such as fault detection and remote
20 monitoring.
21
22 **Q185. Why was the Station Upgrade: 120kV Relay Upgrades for ITC Projects created?**
23 **A185.** ITC initiates work to upgrade the 120kV relaying at points of interconnection with
24 DTE Electric. The Company supports the ITC projects by upgrading obsolete DTE
25 Electric relays for which OEM support and replacement parts are no longer available,

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allowing the work to be completed at a lower cost than reactive repairs or separate planned capital projects. This coordinated approach allows relay upgrades to be completed proactively during planned outages, thereby avoiding unplanned or extended shutdowns that could otherwise be required if relay failures occur during periods of peak system loading, when operational flexibility is limited and customer impacts would be greatest.

Q186. What is the scope of the Station Upgrade: 120kV Relay Upgrades for ITC Projects?

A186. The Company has and will perform the 120 kV relay upgrades as shown in Table 19.

Table 19 - Station Upgrades: 120kv Relay Upgrades by Year

Year	Station	Number of Upgrades
2026	Bad Axe	2
2026	Southfield	1
2026	Placid	3
2027	Elm	2
2027	Superior	1
2027	Medina	2
2027	Venoy	2

Q187. What are the customer benefits of the Station Upgrade: 120kV Relay Upgrades for ITC Projects?

A187. The projects offer several benefits to customers. First, the work will be planned, designed, and executed during off-peak loads in cooperation with ITC, and it will not

Line No.

impact the timelines of ongoing projects. Thus, replacing relay panels during a shutdown for an ITC-driven project will avoid a separate future shutdown. Second, the smart microprocessor relays generate alarms, Light Emitting Diodes (LEDs) and time-stamped event reports for troubleshooting and maintenance targets, thereby avoiding outages or reducing outage durations. Third, additional design in selected protective relays provides enhanced remote control. Relay failure alarms provide advanced notice to replace the failed relay before an actual event without a shutdown due to redundancy in the protective scheme. These relaying upgrades will contribute to strengthening the electric grid.

Q188. Why was the Station Upgrade: Navarre Station project created?

A188. The Navarre Station requires a comprehensive station upgrade due to aged 24 kV relay panels that are outdated (60+ years old) and cannot be maintained or modified as well as at risk-breakers and disconnects. Further, space constraints prevent the installation of new panels, necessitating a new configuration.

Q189. What is the scope of the Station Upgrade: Navarre Station project?

A189. The scope of the Station Upgrade: Navarre project is to replace 20 24kV oil circuit breakers with gas circuit breakers, replace existing relay panels with 35 new microprocessor-based relay panels, and remove oil circuit breakers and associated relay panels. The new relay panels will include three bus panels and one under-frequency panel.

Line No.

Q190. What are the customer benefits of the Station Upgrade: Navarre Station project?

A190. The station upgrades at Navarre Station will include removing at-risk relays, which will result in improved fault detection and response to overloads. The station upgrades also allow for remote modification of relay settings, which means fewer field visits and reduction in reactive costs during non-storm and storm events.

XI. Preventative Maintenance ("PM") Program

Q191. What is the PM program?

A191. The Company's PM program encompasses inspection of selected overhead equipment, underground, and substation assets, netbank structure inspections and repairs, and structural testing activities. It has three primary objectives: (1) control or reduce equipment-related outages, (2) maximize the total life expectancy of the equipment at minimum lifecycle cost while maintaining safety and reliability, and (3) acquire timely asset performance and condition data to support trend data analysis and identify potential issues.

DTE Electric Engineering developed the program based on DTE Electric's maintenance policies, which set inspection scope and intervals based on manufacturer's recommendations, industry standards and best practices, historical inspection results and equipment condition data, engineering studies, and benchmarking with utility peers.

The Company continues to review and refine its maintenance policies to find efficiencies and reduce failures. Examples of the continuous improvements previously integrated into the PM program include:

Line No.

- Changing inspection intervals based on engineering analyses of inspection results and equipment failures (condition-based maintenance).
- Using substation predictive maintenance (SPdM) data to drive inspection timelines instead of time-based inspections, to be aligned with condition-based maintenance principles and to achieve cost efficiency.
- Reducing required maintenance activities through the use of new technologies (e.g., smart relays).
- Coordinating inspection intervals on different equipment to reduce the need for multiple shutdowns.

Most recently, the Company has implemented several process and quality enhancements to further strengthen the PM program, including the following:

- Digitized inspection forms and deployed mobile inspection tools to field crews, enabling inspection data to be captured electronically and more consistently in the field.
- Established a formal CM process to ensure that material issues identified during PM inspections are promptly evaluated, prioritized, and remediated.
- Enhanced quality assurance and quality control practices by utilizing internal inspectors to review and validate the quality of inspections performed by contractors, improving data reliability and maintaining adherence to Company inspections policies.

The Company's PM program aligns with industry best practices, and is essential to minimizing unplanned outages, maintaining reliable service, and extending equipment life. This program improves performance, reduces the need for frequent replacements,

Line No.

1 prevents premature failures, and reduces downtime, enhancing overall system
2 efficiency and reliability. Preventive maintenance is cost-effective, avoiding the
3 higher expenses of emergency repairs and, by extending equipment life, reducing
4 equipment replacements costs. By collecting performance and condition data, it
5 enables better analysis and proactive decision-making. It also addresses potential
6 safety hazards before they become actual, maintaining a safe working environment
7 and protecting the community. Additionally, preventive maintenance lowers reactive
8 costs by avoiding expensive unplanned outages and urgent repairs, as I discuss later
9 in my testimony.
10
11 **Q192. What equipment is included in the Company's PM program?**
12 **A192.** DTE Electric's preventative maintenance program for distribution and subtransmission
13 categorizes equipment into three groups: (1) substations, (2) overhead equipment, and
14 (3) underground, as shown in Tables 20 – 22 below.

Line
No.

1 **Table 20 - Preventative Maintenance Activities – Substations**

Asset	Population (approx.)	General Inspection Cycle (years)
120kV disconnects	352	10
120kV breakers	32	10/12
24/40kV breakers	1,055	3/10/12
Distribution breakers	5,381	3/10/12
Buses	244	10
Regulators	249	10
Portable substations	10	1
Single tap substations	112	10
13.2kV capacitor banks	231	1
AC netbank transformers	505	5
AC netbank structures	384	10
DC systems	651	1
Dissolved gas analysis (DGA)	3,345	1
Substation predictive maintenance (SPdM)	1,640	3
Voltage control periodics	1,717	1
Relay periodics	9,887	5/7/10

Line No.

1 **Table 21 - Preventative Maintenance Activities – Overhead**

Asset	Population (approx.)	General Inspection Cycle (years)
40kV pole top switches	868	8
Distribution remote devices	1,894	4/8
OH capacitor & regulator controls	5,120	1
OH distribution device battery replacements	1,894	4
Towers	500	10
DTEE equipment in high rise structures	52	10

2

3 **Table 22 - Preventative Maintenance Activities – Underground**

Asset	Population (approx.)	General Inspection Cycle (years)
Primary switch cabinets	1,914	5/10/15
Manholes	18,610	10
URD Padmounted Transformers	148,180	10
Vaults	13	2

4

5 **Q193. What are the benefits of the PM program?**

6 **A193.** The PM program reduces equipment failures and extends asset life, providing
7 reliability and asset-health benefits. In response to the Commission's Order in the Audit
8 Report requesting an analysis of the trade-offs between capital and O&M, DTE Electric

Line No.

1 included PMs in its GPM for the first time. As detailed in the DSP[56] Section on the
2 Global Prioritization Model (GPM), the Company selected the top five PMs by annual
3 investment for inclusion: distribution remote devices (SCADA), distribution breakers,
4 URD pad-mount transformers, overhead capacitor and regulator controls, and 40 kV
5 pole-top switches. Table 23, below, presents the GPM ranking for the in-scope PM
6 programs and highlights the impact dimensions with high scores that informed those
7 rankings. The incorporation of PM programs into the GPM resulted in comparatively
8 high rankings across the portfolio, reflecting their strong performance across
9 reliability-focused impact dimensions and their ability to deliver significant benefits
10 per dollar invested.
11
12 **Table 23 - PM Program GPM Ranking and Key Impact Dimensions**

PM Programs (in-scope for GPM)	GPM Ranking	Key Impact Dimension(s) with High Scores
Breakers	1	• SAIDI • SAIFI • Capital Avoidance
40kV Pole-Top Switches	2	• SAIDI • SAIFI
Distribution Remote Devices	6	• SAIDI • SAIFI
Overhead Capacitor & Regulator Controls	8	• O&M Avoidance • Capital Avoidance
URD Pad-Mounted Transformers	9	• Reduce Electrical Hazards

[56] Exhibit A-23, Sch M1, Section 5.2.4 (Global Prioritization)

Line No.

Q194. Is the Company currently meeting the general inspection cycles listed in Tables 20 – 22 above?

A194. No. The Company currently has an inspection and maintenance backlog.[57] In recent years, the Company's PM program has not consistently met the inspection cycles outlined in Tables 20 – 22. The Company's plan to address this is to increase PM inspections to align with stated inspection cycles is described later in my testimony.

Q195. What categories of maintenance activities make up the maintenance backlog?

A195. The maintenance backlog includes two categories of maintenance: (1) Preventative Maintenance ("PM") and (2) Corrective Maintenance ("CM"). PMs are past due inspections and routine maintenance, as defined in Tables 20 – 22. CM, in contrast, includes damaged or defective electrical or structural system equipment that needs to be repaired or replaced. CM backlogs are discussed later in my testimony.

Q196. Did the Audit Report include recommendations related to the PM program?

A196. The Audit Report included general recommendations related to the Company addressing its inspection and maintenance backlog.[58] Relative to the PM program scope, the Audit Report included the following four recommendations related to specific equipment groups:

> 1) "Provide the resources to reduce the padmount transformer inspection backlog and determine an optimum inspection cycle…., 2) Complete manhole inspections on the established cycle, 3) Clear SCADA device backlogs…., 4) Evaluate the cyclical conduct of substation infrared and oil testing."[59]

[57] Case No. U-21305 Audit Report, Part Two, Chapter 1, pp. 44-45
[58] Case No. U-21305 Audit Report, Part Two, Chapter 1, pp. 44-45.
[59] Case No. U-21305 Audit Report, Part Two, Chapter 1, pp. 44-45.

Line No.

1 **Q197. How did the Company respond to the Audit Report's recommendations related to**
2 **the PM program?**
3 **A197.** DTE Electric has taken actions responsive to the Audit Report's recommendations
4 related to the PM program. The Company is addressing inspections for padmount
5 transformers[60], SCADA devices, and manholes[61] by targeting annual inspections levels
6 consistent with established maintenance cycle targets to prevent the formation of new
7 backlog, in alignment with audit recommendations. The Company is requesting
8 additional funding in this case to maintain this cycle. Additionally, DTE Electric is
9 conducting routine oil testing for power transformers and evaluating further testing
10 methods for substation equipment. Specific to the manhole inspections, the Company
11 supports completing inspections on the established maintenance cycle, but it does not
12 agree that there is an underlying safety concern associated with that backlog, as the
13 Company's standard practice requires an inspection before any entry into a manhole.
14
15 **Q198. What is DTE Electric's plan and costs to meet inspection targets and reduce the**
16 **overall PM backlog?**
17 **A198.** The Company has developed a two-pronged approach to address the PM backlog.
18 The first prong is to prevent the backlog from growing. The Company will increase
19 ongoing PM inspection activity to levels consistent with established maintenance cycle
20 targets to prevent the formation of new backlog, in alignment with audit
21 recommendations. Year-over-year spending on PM inspections has typically been
22 approximately $10 million, which is insufficient to maintain the required inspection
23 cycles. An additional annual investment of $2.3 million above the current $10 million

[60] Case No. U-21305 Implementation Plan for the DTE Electric Audit Report, p 7
[61] Case No. U-21305 Implementation Plan for the DTE Electric Audit Report, p 8

is needed to support compliance with established inspection intervals. This allows the Company to stay current on PM inspections and prevents new backlogs from forming.

The second prong is to eliminate the existing backlog over a three-year period. The Company plans to complete approximately one-third of the existing PM backlog in each of 2026, 2027, and 2028. The Company is implementing a backlog-reduction initiative designed to eliminate approximately one-third of the current PM backlog, totaling approximately 103,400 units as of December 31, 2025, over a three-year period. This initiative requires an additional $5 million per year in 2026, 2027, and 2028, with no additional backlog-reduction funding anticipated in 2029 or 2030. The Company will prioritize the areas identified in the Audit Report, including overdue PM activities for pad-mount transformers, manholes, and SCADA devices. This two-pronged approach allows the Company to eliminate the backlog and prevents a new backlog from forming.

Q199. Will there be new incremental PM effort and expense once the backlog is eliminated and appropriate PM cycles are achieved?

A199. Yes. In addition to the incremental investments needed to maintain established inspection cycles and resolve the PM backlog, the Company anticipates increased PM inspection requirements driven by system modernization and automation initiatives. The Company estimates that the growing fleet of automation assets placed into service will require incremental funding of approximately $0.2 million in 2026, rising to about $4.7 million by 2030. DSP Exhibit 6.10 summarizes total projected PM and Inspections investment needs from 2026 - 2030[62]. Together, these near-term actions will restore

[62] Exhibit A-23, M1, section 6, Preventative Maintenance and Inspections, Exhibit 6.10

compliance with inspection cycles, enhance asset condition visibility, reduce outage risk, and ultimately improve overall reliability.

Q200. What is the Company requesting in the instant case related to the PM program?

A200. To implement the plan to reduce the PM backlog and increase PM in an amount consistent with target maintenance cycles and new PM requirements, the Company is requesting an incremental $8.4 million in O&M for the bridge period and an additional $250,000 in the projected test year.[63]

XII. Corrective Maintenance ("CM") Program

Q201. What is the CM program?

A201. The CM program focuses on repairing or replacing electrical and structural assets that have failed in-service, show signs of imminent failure, are damaged by storms or external events, or present unsafe operating conditions. Collectively, these activities maintain equipment functionality and safety and align with good utility practice. CM activities are identified through several pathways:

- **Assets Failed or Have Potential to Fail:** An asset that has lost or has potential to lose its ability to perform one or more required functions within specified performance limits and requires repair, replacement, or removal from service.
- **Assets in Abnormal Configuration:** An asset that remains operational but is operating outside its normal, designed, or expected configuration, condition, or parameter range, indicating elevated risk of failure if not addressed.
- **Assets Damaged by Storms or External Events**: Repair or replacement of utility poles, overhead conductors, switching points, and oil-filled equipment.

[63] Ex. A-13, C5.6 Revised, p. 2

- **Routine Maintenance Findings:** Issues discovered during routine inspections, condition monitoring, asset health, or reliability reviews.
- **Preventative Maintenance Findings:** A PM inspection identifies a failure or abnormal condition or an issue that poses a safety or environmental risk, initiating immediate remediation.

Q202. How does the CM program benefit customers?

A202. The CM program minimizes equipment downtime when failures occur. By addressing asset failures and abnormal conditions quickly, CM decreases the likelihood of extended outages, prevents cascading failures, and helps the grid withstand increasingly severe weather. Timely repairs also protect customers, utility workers, and first responders by eliminating hazards such as exposed energized equipment, deteriorated manholes, and transformer oil leaks. From a cost effectiveness standpoint, CM reduces expenses associated with emergency repairs and premature asset replacements and extends the useful life of infrastructure where repair is feasible. Integrating PM inspection data into corrective workflows enables the Company to prioritize issues efficiently, plan resources more effectively, and refine maintenance strategies over time.

Q203. Does the Company have a CM backlog, and what factors contributed to its development?

A203. Yes. The Company has identified a corrective maintenance backlog. Elevated incoming CM volumes continue to be driven primarily by aging infrastructure and increasingly severe weather conditions.

Line No.

1 The major ice storm that occurred in 2023, for example, resulted in widespread damage
2 to poles, conductors, and pole-top equipment, significantly increasing corrective
3 maintenance workload. In addition, periods of low ambient temperatures contribute to
4 increased reports of low oil levels in substation transformers. This condition is
5 attributable to the contraction of transformer oil as temperatures decrease, which leads
6 to a measurable rise in low oil level indications and corresponding corrective
7 maintenance activity. Together, these factors have increased the volume of identified
8 corrective maintenance work and contributed to the development of the current CM
9 backlog.
10
11 **Q204. Did the Audit Report include recommendations related to the CM program?**
12 **A204.** Yes, The Audit Report included general recommendations related to the Company
13 addressing its inspection and maintenance backlog. Relative to the CM program scope,
14 the Audit Report included the following recommendation related to the backlog of
15 URD cable failures: "Dedicate the resources required to manage the high number of
16 backlogged loop repairs." [64]
17
18 **Q205. How did the Company respond to the Audit Report's recommendations related to**
19 **the CM program?**
20 **A205.** DTE Electric has taken actions responsive to the Audit Report's recommendations
21 related to the CM program. The Company is addressing CM associated with URD open
22 loops, in addition to the other CM work types identified in Table 24. With respect to
23 open-loop repairs and replacements, the Company reduced the related CM backlog by
24 approximately 15 percent between August 2025 and March 2026. Additional

[64] Case No. U-21305 Audit Report, Part Two, Chapter 1, pp. 44

Line No.

1 discussion of CM backlog reduction efforts across all CM work types is provided later
2 in my testimony.
3
4 **Q206. How does the Company determine what corrective maintenance activities are in**
5 **the maintenance backlog?**
6 **A206.** The Company sets standard repair expectations and timeframes for completing CMs to
7 maintain reliability equipment performance and reduce potential service interruptions.
8 Repairs or replacements delayed beyond the defined timeframes are referred to as a
9 backlog.
10
11 **Q207. Which types and amounts of corrective maintenance activities contribute to the**
12 **maintenance backlog?**
13 **A207.** As reported in the August 2025 backlog report in Case No. U-21305, the Company
14 identified 1,561 backlogged CM activities across multiple asset categories. Since then,
15 the Company has reduced the backlog by approximately 24%, resulting in a current
16 total of roughly 1,181 outstanding activities. Table 24 provide details on the backlog
17 by asset category as of March 12, 2026. The most significant reductions occurred
18 within storm-related categories, lowering the number of CM backlog jobs associated
19 with assets damaged by storms and other external events. While some backlog remains
20 in that area, the progress achieved now allows the Company to broaden its focus to
21 other CM categories, including Trouble Requests for Shutdowns (TRSDs), Electronic
22 Turnover Cards (ETOs), and SCADA devices. The Company will continue prioritizing
23 backlog mitigation through 2026 and beyond to achieve and sustain compliance with
24 established maintenance standards.

Line No.

1 **Table 24 - CM Backlog Activities, August 2025 to March 2026**

CM Category	Work Type	CM Backlog Activities		Percent Change
		As of Aug. 15, 2025	As of Mar. 12, 2026	
Assets Failed or Potential Fail	TRSDs	88	97	10%
Assets in Abnormal Configuration	ETOs	767	738	-4%
	Open Loop Repairs or Replacements	117	100	-15%
Assets Damaged by Storms or External Events	Poles	188	68	-64%
	Pole-Top Equipment	136	31	-77%
	Wire	102	14	-86%
	Oil Filled Equipment	29	7	-76%
Control, Monitoring, and Automation Devices	SCADA	134	126	-6%
Total CM Backlog		**1,561**	**1,181**	**-24%**

2

3 **Q208. What actions is the Company taking to manage and reduce its backlog of CM**
4 **work and prevent future backlog growth?**

5 **A208.** The Company will continue to implement a structured, system-wide approach to reduce
6 the backlog of CM jobs. This includes maintaining a standardized, transparent view of
7 all backlog work, strengthening intake and prioritization processes based on safety,
8 reliability, and operational risk, executing targeted backlog-reduction initiatives, and
9 tracking key performance metrics such as backlog age, weeks of backlog, and schedule
10 compliance. The Company has also established a sustainable governance model that
11 assigns clear ownership and accountability for backlog performance, incorporates
12 routine management review and escalation thresholds, aligns funding and resource
13 decisions with risk-based priorities, and monitors compliance with established

maintenance cycles. This governance framework is designed to ensure sustained backlog control and prevent future backlog growth.

Q209. What did the Company request in Case No. U-21860 to address the CM backlog?

A209. The Company requested $7.3 million in incremental O&M funding and $23.5 million in incremental capital expenditures for 2026 to address the existing maintenance backlog.

Q210. How has the Commission responded to the Company's request in Case No. U-21680 to reduce the CM backlog?

A210. The Commission approved the O&M requests for CM. While the Commission disallowed the capital CM requests, it went on "to clarify that the disallowances are based on the fact that additional support is needed for increased investment levels, which must align with future distribution plans, not an indication that preventative maintenance and corrective maintenance should not be performed."[65]

Q211. Has the Company determined whether additional investments are required to eliminate the CM backlog, and what is the basis for this determination?

A211. Yes. The Company has conducted a comprehensive analysis of incoming and completed CM activities over the past two years and assessed their impact on the CM backlog. For the combined categories of CM activities, TRSDs, and ETOs, incoming activities increased from 2,908 in 2024 to 3,129 in 2025, while completed activities increased from 2,953 to 3,172 over the same period. In both years, the number of

[65] Case No. U-21860 Order dated February 24, 2026, p. 98-99

Line No.

completed activities exceeded the number of incoming activities, resulting in a modest reduction in the CM backlog within these categories.

However, to fully address and eliminate the remaining CM backlog over the next five years, the Company has determined that additional investments will be necessary. These investments are required so that the Company can continue to complete both incoming CM activities and outstanding backlog work. The specific investment requirements to achieve these objectives are described in greater detail later in my testimony.

Q212. Has the Company determined the cost to complete the CM backlog?

A212. Yes, the Company determined the cost to complete the CM backlog as of March 15, 2026. The projected capital and O&M needs for CM work over the next five years, 2026-2030, including investment necessary to clear the CM backlog and resolve recent PM findings, are provided in Table 25, below. Capital funds required are incremental to the base budget allocations to remediate identified issues and address outstanding backlogs. O&M funds represent the total investments necessary to maintain compliance in base operations, address incremental corrective maintenance work from PMs, and resolve the existing CM backlog.

Line No.

1 **Table 25 - Investment Plan for CM, 2026-2030 ($ millions)[66]**

	2026	2027	2028	2029	2030	2026 - 2030 Total
Capital	35.0	33.0	21.7	20.6	30.0	**140.3**
O&M	19.9	19.8	18.9	18.8	17.1	**94.5**

2

3 **Q213. What is the Company requesting in the instant case related to the CM backlog?**

4 **A213.** To implement the Company's plan to reduce the CM backlog, the Company requires
5 an incremental $9.1 million in O&M,[67] and $31.1 million in reactive capital[68] in the
6 projected test year.

7

8 **Q214. Does this complete your direct testimony?**

9 **A214.** Yes, it does.

66 Totals may not match exactly to the mathematical summation in the table due to rounding of the source data.
[67] Case No. U-22046, Ex. A-13 C5.6 Revised, p. 2, Other Projected Adjustments
[68] Case No. U- 22046, Ex. A-12, B5.4 Revised, p. 3 line 29, column (h)

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Distribution Plant
($000)

Case No.: U-22046
Exhibit: Revised A-12
Schedule: Revised B5.4
Witness: B. L. Hill 1/, 2/
J. E. Robinson 3/
R. M. Stowe 4/
S. P. Rademacher 5/
P. Sharma 6/

	(a)		(b)	(c)	(d)	(e)		(f)
					Capital Expenditures			
			Historical	Projected Bridge Period				Projected Test Year
Line No.	Description		12 mos. ended 12/31/2025	12 mos. ending 12/31/2026	2 mos. ending 2/28/2027	14 mos. ending 2/28/2027		12 mos. ending 2/29/2028
1	**Base Capital Programs**							
2	Emergent Replacements							
3	Storm	1/	44,067	215,270	36,955	252,225		222,800
4	Non - Storm	1/	415,202	316,632	53,856	370,488		322,662
5	Substation Reactive	1/	75,406	55,228	8,879	64,108		53,533
6	Emergent Replacement Reduction Based on Strategic Spend	7/	-	(26,477)	(4,646)	(31,123)		(28,119)
7	Subtotal Emergent Replacements		534,675	560,654	95,044	655,698		570,877
8	Customer Connections, Relocations & Other (CCRO)							
9	Connections and New Load	2/	290,825	307,159	53,523	360,682		323,727
10	Relocations	2/	41,001	42,258	6,396	48,654		38,561
11	Electric System Equipment	2/	27,377	36,626	6,287	42,913		37,907
12	NRUC and Improvement Blankets	2/	43,979	30,077	5,163	35,240		31,129
13	General Plant, Tools & Equipment and Miscellaneous	2/	7,126	6,485	1,113	7,598		6,712
14	Public Lighting Department Project	2/	26	-	-	-		-
15	Subtotal Customer Connections, Relocations & Other		410,335	422,605	72,483	495,088		438,036
16	Customer Advances for Construction	2/	(30,303)	(56,009)	(10,002)	(66,011)		(60,304)
17	Subtotal CCRO Net Customer Advances for Construction		380,032	366,596	62,480	429,077		377,732
18	**Total Base Capital Programs**		**914,707**	**927,251**	**157,524**	**1,084,775**		**948,609**
19	**Strategic Capital Programs**							
20	Resilience and Hardening	3/	315,677	192,273	38,478	230,751		281,180
21	Redesign and Modernization	4/	148,068	260,931	39,504	300,435		249,169
22	Technology and Automation	5/	128,885	80,520	30,928	111,448		191,363
23	Grid Edge and Distributed Intelligence	5/, 6/	6,825	15,200	3,333	18,533		27,617
24	**Total Strategic Capital Programs**		**599,454**	**548,924**	**112,244**	**661,167**		**749,329**
25	**Total Capital**		**1,514,161**	**1,476,174**	**269,768**	**1,745,942**	-	**1,697,938**

1/ Exhibit A-12, Schedule B5.4 - page 3
2/ Exhibit A-12, Schedule B5.4 - pages 4-5, lines 12, 23, 30, 35, 39, 40 & 42
3/ Exhibit A-12, Schedule B5.4 - page 9, line 33
4/ Exhibit A-12, Schedule B5.4 - page 12, line 96
5/ Exhibit A-12, Schedule B5.4 - page 13, line 52 and page 14, lines 2-4
6/ Exhibit A-12, Schedule B5.4 - page 14, line 5

7/ The Company's Reliability Model demonstrates approximately $27.9 million of savings per year as shown on Exhibit A-12 Schedule B5.4, page 1 line 6. Operation of the updated Reliability Model results in savings of $30.9 million in 2026, $33.3 million in 2027 and 35.4 million in 2028. The Company's updated Emergent Savings are higher than in Exhibit A-12, Schedule B5.4, page 1, line 6 due to timing of completion of the model.

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Distribution Plant
($000)

Case No.: U-22046
Exhibit: Revised A-12
Schedule: Revised B5.4
Witness: B. L. Hill 1/, 2/
J. E. Robinson 3/
R. M. Stowe 4/
S. P. Rademacher 5/
P. Sharma 6/

	(a)		(b)	(c)	(d)	(e)	(f)	(g)
						Capital Expenditures		
			Historical	Normalization	Adjusted	Projected Calendar Year		
Line No.	Description		12 mos. ended 12/31/2025	Adjustment 8/	Historical Test Period	12 mos. ending 12/31/2026	12 mos. ending 12/31/2027	12 mos. ending 12/31/2028
					sum (b) thru (c)			
1	**Base Capital Programs**							
2	Emergent Replacements							
3	Storm	1/	44,067	165,136	209,203	215,270	221,728	228,158
4	Non - Storm	1/	415,202	(141,355)	273,847	316,632	323,135	320,300
5	Substation Reactive	1/	75,406	(25,248)	50,158	55,228	53,276	54,818
6	Emergent Replacement Reduction Based on Strategic Spend	7/	-	-	-	(26,477)	(27,876)	(29,333)
7	Subtotal Emergent Replacements		534,675	(1,467)	533,208	560,654	570,263	573,944
8	Customer Connections, Relocations & Other (CCRO)							
9	Connections and New Load	2/	290,825			307,159	321,137	336,676
10	Relocations	2/	41,001			42,258	38,376	39,489
11	Electric System Equipment	2/	27,377			36,626	37,724	38,818
12	NRUC and Improvement Blankets	2/	43,979			30,077	30,979	31,878
13	General Plant, Tools & Equipment and Miscellaneous	2/	7,126			6,485	6,680	6,873
14	Public Lighting Department Project	2/	26			-	-	-
15	Subtotal Customer Connections, Relocations & Other		410,335			422,605	434,896	453,734
16	Customer Advances for Construction	2/	(30,303)			(56,009)	(60,014)	(61,754)
17	Subtotal CCRO Net Customer Advances for Construction		380,032			366,596	374,883	391,980
18	**Total Base Capital Programs**		**914,707**			**927,251**	**945,146**	**965,924**
19	**Strategic Capital Programs**							
20	Resilience and Hardening	3/	315,677			192,273	230,870	159,563
21	Redesign and Modernization	4/	148,068			260,931	237,025	309,890
22	Technology and Automation	5/	128,885			80,520	185,567	103,680
23	Grid Edge and Distributed Intelligence	5/, 6/	6,825			15,200	20,000	65,700
24	**Total Strategic Capital Programs**		**599,454**			**548,924**	**673,462**	**638,833**
25	**Total Capital**		**1,514,161**			**1,476,174**	**1,618,608**	**1,604,757**

1/ Exhibit A-12, Schedule B5.4 - page 3
2/ Exhibit A-12, Schedule B5.4 - pages 4-5, lines 12, 23, 30, 35, 39, 40 & 42
3/ Exhibit A-12, Schedule B5.4 - page 9, line 33
4/ Exhibit A-12, Schedule B5.4 - page 12, line 96
5/ Exhibit A-12, Schedule B5.4 - page 13, line 52 and page 14, lines 2-4
6/ Exhibit A-12, Schedule B5.4 - page 14, line 5

7/ The Company's Reliability Model demonstrates approximately $27.9 million of savings per year as shown on Exhibit A-12 Schedule B5.4, page 1 line 6. Operation of the updated Reliability Model results in savings of $30.9 million in 2026, $33.3 million in 2027 and 35.4 million in 2028. The Company's updated Emergent Savings are higher than in Exhibit A-12, Schedule B5.4, page 1, line 6 due to timing of completion of the model.

8/ Normalization Adjustment:

	Amount
Emergent Replacements Exh. B5.4, p.3, Line 25, col. (j)	(1,467)

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Distribution Plant - Emergent Replacements
($000)

Case No.: U-22046
Exhibit: Revised A-12
Schedule: Revised B5.4
Witness: B. L. Hill
J. E. Robinson 2/
Page: 3 of 22

	(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
							Capital Expenditures					
Line No.	Description		Historical 12 mos. ended 12/31/2021	Historical 12 mos. ended 12/31/2022	Historical 12 mos. ended 12/31/2023	Historical 12 mos. ended 12/31/2024	Historical 12 mos. ended 12/31/2025	Historical 5-year average	3/1/2027 2/29/2028 Test Year	1/1/2025 - 12/31/2025 Historical	Emergent Replacements Adjustment	In Service Year
											(h) - (i)	
1	**Base Capital Programs**											
2	**Emergent Replacements**											
3	**Storm**		395,286	181,326	273,538	151,799	44,067	209,203	209,203	44,067	165,136	Annual
4	Inflation 1/1/26 -12/31/26	2.90%							6,067	1,278	4,789	
5	Inflation 1/1/27 -12/31/27	3.00%							6,458	1,360	5,098	
6	Inflation 1/1/28 -2/29/28	0.48%							1,072	226	846	
7	Projected Storm Replacements								222,800	46,932	175,868	
8	**Non-Storm**		209,236	263,014	209,356	272,424	415,202	273,847	273,847	415,202	(141,355)	Annual
9	Inflation 1/1/26 -12/31/26	2.90%							7,942	12,041	(4,099)	
10	Inflation 1/1/27 -12/31/27	3.00%							8,454	12,817	(4,364)	
11	Inflation 1/1/28 -2/29/28	0.48%							1,403	2,127	(724)	
12	Projected Non-Storm Replacements								291,645	442,187	(150,542)	
13	Projected 2026 Corrective Maintenance	2/							34,844			
14	Projected 2027 Corrective Maintenance	2/							32,893			
15	Projected 2028 Corrective Maintenance	2/							21,641			
16	**Substation Reactive**		46,008	40,382	41,178	47,816	75,406	50,158	50,158	75,406	(25,248)	Annual
17	Inflation 1/1/26 -12/31/26	2.90%							1,455	2,187	(732)	
18	Inflation 1/1/27 -12/31/27	3.00%							1,548	2,328	(779)	
19	Inflation 1/1/28 -2/29/28	0.48%							257	386	(129)	
20	Projected Substation Reactive Replacements								53,418	80,306	(26,889)	
21	Projected 2026 Substation Facility Repair	4/							3,500			
22	Projected 2026 Corrective Maintenance	2/							116			
23	Projected 2027 Corrective Maintenance	2/							116			
24	Projected 2028 Corrective Maintenance	2/							116			
25	**Total Emergent Replacements Normalization Adjustment (Line 3 + Line 8 + Line 16) Pre-inflation**								**533,208**	**534,675**	**(1,467)**	**1/**
26	Inflation 1/1/26 -12/31/26	2.90%							15,463	15,506	(43)	
27	Inflation 1/1/27 -12/31/27	3.00%							16,460	16,505	(45)	
28	Inflation 1/1/28 -2/29/28	0.48%							2,731	2,739	(8)	
29	Test Year Corrective Maintenance (Line 14+23 *(10/12) + Line 15+24 *(2/12))								31,133			
30	Total Projected Emergent Replacements Expense (Lines 25 thru 29)								**598,996**	**569,425**	**(1,562)**	
31	Test Year Emergent Replacement Reduction Based on Strategic Spend								**(28,119)**			**3/**
32	Total Projected Emergent Replacements Expense less Test Year Emergent Reduction based upon Strategic Spend								**570,877**			

1/ Historical normalization adjustment carried to Base Capital Programs - see Exhibit A-12, B5.4, page 2, line 7, col. (c)
2/ Corrective Maintenance sponsored by Witness Robinson
3/ Test Year Emergent Replacement Reduction Based on Strategic Spend carried from Distribution Plant - See Exhibit A-12, B5.4, page 1, line 6, col. (f)
4/ Due to a drafting error, this exhibit reflects a request of $3.5 million. The Company's actual requested amount is $2.3 million.

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Distribution Plant - Connections, Relocations and Other
($000)

Case No.: U-22046
Exhibit: Revised A-12
Schedule: Revised B5.4
Witness: B. L. Hill
M. Kabashi 2/
Page: 4 of 22

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
							Capital Expenditures				
	Three year without CDA		Historical	Historical	Historical	Historical	Projected Bridge Period			Test Year	
Line No.	Description		12 mos. ended 12/31/2023	12 mos. ended 12/31/2024	12 mos. ended 12/31/2025	3-year average	12 mos. ending 12/31/2026	2 mos. ending 2/28/2027	14 mos. ending 2/28/2027	12 mos. ending 2/29/2028	In Service Year
1	**Connections and New Load**										
2	Small Load Growth Projects (Blanket)		-	-	36,717		37,782	6,486	44,268	39,104	Annual
3	Customer Connections		-	-	174,215		179,267	30,774	210,041	185,537	Annual
4	Customer Connections CIAC		-	-	(23,154)		(23,826)	(4,090)	(27,916)	(24,659)	
5	Projected Customer Connections CIAC New Rate Incremental				-		(18,970)	(3,552)	(22,522)	(21,418)	
6	Projected Customer Connections (Net of CIAC)				151,060		136,472	23,132	159,603	139,460	
7	New Business Projects	1/	-	-	79,893		82,210	14,113	96,323	85,086	Annual
8	New Business Projects CIAC		-	-	(3,841)		(3,953)	(679)	(4,631)	(4,091)	
9	Projected New Business CIAC New Rate Incremental				-		(3,147)	(589)	(3,736)	(3,553)	
10	New Business Projects (net of CIAC)				76,052		75,111	12,845	87,956	77,442	
11	Incremental Infrastructure for EV	2/					7,900	2,150	10,050	14,000	Annual
12	**Total Connections and New Load**				**290,825**		**307,159**	**53,523**	**360,682**	**323,727**	
13	**Total Connections and New Load CIAC**				(26,996)		(49,895)	(8,910)	(58,806)	(53,721)	
14	**Total Connections and New Load (Net of CIAC)**				263,830		257,264	44,612	301,877	270,006	
15	**Relocations**										
16	Small Relocations Projects (Blanket)		-	-	11,284		11,612	1,993	13,605	12,018	Annual
17	Major Infrastructure Relocation Project										
18	I-375 Relocations				4,793		5,000	-	5,000	-	2026
19	Relocation Projects (excl. Major Infrastructure Projects)	3/	-	-	24,923		25,646	4,403	30,049	26,543	Annual
20	Relocation Projects CIAC		-	-	(3,308)		(3,404)	(584)	(3,988)	(3,523)	
21	Projected Relocations CIAC New Rate Incremental				-		(2,710)	(507)	(3,217)	(3,060)	
22	Relocation Projects (Net of CIAC)				21,616		19,533	3,311	22,843	19,961	
23	**Total Relocations**				**41,001**		**42,258**	**6,396**	**48,654**	**38,561**	
24	**Total Relocations CIAC**				(3,308)		(6,114)	(1,092)	(7,205)	(6,582)	
25	**Total Relocations (Net of CIAC)**				37,694		36,144	5,304	41,449	31,979	

1/ Exhibit A-12, Schedule B5.4 - page 7, line 93
2/ Incremental EV Chargers sponsored by Witness M. Kabashi
3/ Exhibit A-12, Schedule B5.4 - page 8, line 33

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Distribution Plant - Connections, Relocations and Other
($000)

Case No.: U-22046
Exhibit: Revised A-12
Schedule: Revised B5.4
Witness: B. L. Hill
M. Kabashi 2/
Page: 5 of 22

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
							Capital Expenditures				
			Historical	Historical	Historical	Historical	Projected Bridge Period			Test Year	
Line No.	Description		12 mos. ended 12/31/2023	12 mos. ended 12/31/2024	12 mos. ended 12/31/2025	3-year average	12 mos. ending 12/31/2026	2 mos. ending 2/28/2027	14 mos. ending 2/28/2027	12 mos. ending 2/29/2028	In Service Year
26	**Electric System Equipment**										
27	Distribution Transformers & Regulators	4/	816	(10,955)	(5,319)		-	-	-	-	Annual
28	Major Equipment		11,470	20,680	5,676	12,609	12,974	2,227	15,202	13,428	Annual
29	Meters		15,384	26,551	27,020	22,985	23,651	4,060	27,711	24,479	Annual
30	**Total Electric System Equipment**		**27,670**	**36,276**	**27,377**		**36,626**	**6,287**	**42,913**	**37,907**	
31	**NRUC and Improvement Blankets**										
32	System Improvements		8,020	14,320	31,707	18,016	18,538	3,182	21,721	19,187	Annual
33	Normal Retirement Unit Changeouts (NRUC)		3,888	5,464	9,715	6,356	6,540	1,123	7,663	6,769	Annual
34	Operational Technologies		7,834	4,182	2,556	4,857	4,998	858	5,856	5,173	Annual
35	**Total NRUC and Improvement Blankets**		**19,742**	**23,967**	**43,979**		**30,077**	**5,163**	**35,240**	**31,129**	
36	**General Plant, Tools & Equipment and Miscellaneous**										
37	Substation Physical Security	5/	88	1	(148)		-	-	-	-	2023
38	General Plant, Tools & Equipment and Miscellaneous		6,002	5,631	7,274	6,302	6,485	1,113	7,598	6,712	Annual
39	**Total General Plant, Tools & Equipment and Miscellaneous**		**6,090**	**5,633**	**7,126**		**6,485**	**1,113**	**7,598**	**6,712**	
40	**Public Lighting Department Project**	6/	2,186	(310)	26		-	-	-	-	2023
41	**Total Customer Connections, Relocations & Other**				410,335		422,605	72,483	495,088	438,036	
42	**Total Cust Connections, Relocations & Other CIAC**				(30,303)		(56,009)	(10,002)	(66,011)	(60,304)	
43	**Total Cust Connections, Relocations & Other Net of CIAC**				380,032		366,596	62,480	429,077	377,732	

4/ Distribution Transformers & Regulators will be charged to specific projects in 2024 and excluded from historical average
5/ Substation Physical Security Project was completed in 2023 and is excluded from the historical average
6/ Public Lighting Department was completed in 2023 and is excluded from the historical average

Michigan Public Service Commission Case No.: U-22046
DTE Electric Company Exhibit: Revised A-12
Projected Capital Expenditures Schedule: Revised B5.4
Distribution Plant - Historical Test Year's Projects Witness: B. L. Hill
($000) Page: 6 of 22

Line No.	(a) Description	(b) Historical 12 mos. ended 12/31/2025
1	**Historical Test Year's New Business Projects:**	
2	HFH new Sub property	8,589
3	Nitro Sub - CKT 3 & 4 (5 mile, Napier & Riidge)	7,677
4	SIGMA (Grayling) Substation OH UG Circuits	7,155
5	SWAN Creek Substation Expansion	6,140
6	Nitro Circuit NITRO09109, NITRO9270 (5 mile, Napier & Riidge)	6,024
7	Nitro Substation and circuit NITRO9621, NITRO9667 (south and r	5,867
8	Fairgrove Substation	5,711
9	CATLI Substation Upgrade (CATLI, Gleenwod, Rubicon)	2,786
10	HFH new Substation	2,549
11	Detroit department of transportation (DDOT - 14044 Schaefer Hw	2,274
12	HFH expansion	1,982
13	TAMRK DC 8937	1,815
14	USA Fortescue Piquette LLC MOS	1,554
15	Cargill Class I Substation (new DTE owned)	1,265
16	Bedrock - Monroe Block Development	1,220
17	Morton (MORTN) Sub - Overhead Circuits (Sheldon/Gilbert/Zacha	1,203
18	New DTE-Owned Class I Substation For Dana Corp	1,091
19	Center of Innovation Vault (Univerity of Michigan)	1,045
20	Morton (MORTN) Sub - Substation, Cable , Conduit (Sheldon/Gilb	1,023
21	Sheridan (Globe) Substation Engineering - DC8034	999
22	GM Orion Expansion Project	971
23	Misc Capital	843
24	Port Hope Substation (Sub and OH work)	826
25	Airport Substation Expansion - Property	791
26	Ford Motor - Artic Substation	766
27	MOS Blanche Sims Elementary School	749
28	New 6.6 MVAR Cap at Derby (Vassar Acquisitions LLC)	709
29	T-Mobile, new circuit OTTWA	669
30	Toyota New Industrial Sub and Line Extension	602
31	602 E. Washington Overhead Removal	569
32	Reservice Children's Hospital of Michigan (CHOM) From MIDTN	511
33	Metamora Substation - Property	502
34	TAMRK New Circuit DC8258	402
35	MOUNTAIN Skid-Mounted Sub	355
36	SIGMA (Grayling) DC 8587 GRAYL Circuit Split	341
37	Sterling Group- Former JLA - Phase 1 of 3	286
38	Amazon MOS Wixom DC9077, DC8228	285
39	Gestamp 40kV Temp Service	258
40	MOHIC Mohican feed for Magna	225
41	COLRD circuit - MOS GM	213
42	GM Pontiac - Tempest Substation Upgrades - Phase I	209
43	SIGMA GRAYL9180 Split & Decommissioning & GRAYL8473 Spl	201
44	NHDSN New Hudson 120kV-13.2kV substation	186
45	CATLI MOS 13 Switchgear (S. Glenwood, Pontiac, Rubicon)	141
46	New DTE-Owned Class I Substation For Magna	124

Line No.	(a) Description	(b) Historical 12 mos. ended 12/31/2025
47	New Hudson (NHDSN) Sub property	103
48	TAMRK Future Circuit DC #9	94
49	Romulus Trade Center, 32870 Wick Rd MOS	90
50	Canton MOS (Circuit MOTT9783)	73
51	MOS 95 & 631 Brown Rd, Orion	67
52	Mystic Cove MOS - Primary Main	65
53	Northland Apartments A and B	63
54	NINMI Circuit -MOS	62
55	New AKRON Circuit (Wanxiang, Novi Sr Living)	55
56	SIGMA (Grayling) GRAYL8517 Circuit Split	54
57	Trunk 2439 Upgrades For Data Substation - 123 Net	50
58	WSU Gateway Theatre Complex	42
59	Airport Substation Expansion	41
60	Basco Development Netbank TRF upgrade	37
61	Ann Arbor Lamdfill (Flare)	29
62	Class-I Subs (Edward C Levy LLC)	26
63	60 Harper MO	24
64	RotoZ Dairy MOS (Convert portion of SNOVR0301)	24
65	Misc Capital	24
66	HUDROE Development	23
67	New DC: Whittier Substation	21
68	Henry Ford Macomb Hospital New Class I Substation	14
69	NP Mound Road Industrial LLC	13
70	770 S Adams MOS	11
71	Blakes Cider Mill - Armada DC8550	9
72	New Class I for Verizon Wireless	9
73	NP Detroit Commerce Center (1450 Plymouth)	7
74	KERN Substation Upgrades	5
75	MOS Feldman Chevrolet	5
76	20400 Ralston (Piston Automotive) MOS	3
77	Buhl Building - 535 Griswold Ave	3
78	MOS Ashley Capitol POLRS & LIVON	2
79	New Class-I Sub for Bedrock/Luxwall	1
80	CORKT Ford Circuits	1
81	Hood Substation - Village at Bloomfield	1
82	MSV MI LLC, 1721 W Pleasant St., River Rouge, MI	1
83	Ann Arbor Solar	0
84	FALCN/CYPRS New Class 'R' 120-13.2kV	0
85	GRAYL DC8517 Circuit Load Relief	0
86	Wayne Criminal Justice Center - CJC CUP	(13)
87	Terry Leright Service Planning Request	(16)
88	ESOC Electric Service	(30)
89	New Hudson (NHDSN) Substation - Walbridge Development	(39)
90	Eastland Commerce Center MOS	(67)
91	Project ONE MOS	(269)
92	Our Next Energy (ONE)	(528)
93	**Total Historical Test Year's New Business Projects**	**79,893**

Michigan Public Service Commission Case No.: U-22046
DTE Electric Company Exhibit: Revised A-12
Projected Capital Expenditures Schedule: Revised B5.4
Distribution Plant - Historical Test Year's Projects Witness: B. L. Hill
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Line No.	(a) Description	(b) Historical 12 mos. ended 12/31/2025
1	**Historical Test Year's Relocation Projects:**	
2	I-94 Holcomb Crossing_UG	7,663
3	I-94 Conner crossing_UG	3,620
4	TRK 5906 Relocation	2,726
5	Ford Oakwood Blvd OH to UG Relocation	1,986
6	Nolan 9865 bridge replacement	1,936
7	Mariners Inn	1,505
8	Rochester Rd Expansion	1,145
9	739 S Washington OCC (was RELO0081)	1,045
10	I-75/Twelve Mile Relocation (COULD MIX w/ RELO0067-01 1-75	867
11	TRK 2455 OH Relocation (ITC)	598
12	Great Lakes Water Authority (GLWA) Freud St Relocation	553
13	TRK 5239 Reconductoring (ITC 120kV)	411
14	33 Eliot CCA Midtown Facility Relocation	372
15	Mt Elliott Pole Relocations	333
16	TRK 422, 459 Decommission - 428 Relocation, Lynch Substation F	148
17	Relocate TRK1418	92
18	Tie 1473 Reloc for ITC Tower Replacement	64
19	I-94 Conner crossing_OH	61
20	Ecorse Southfield bridge UG Relo	29
21	TRK 5239 Reconductoring	17
22	Grand River I-94 Bridge Reconstruction (MDOT)	13
23	I-75 Conflict 511 (MDOT)	3
24	I-94 Cass Bridge Relocation (MDOT)	2
25	New Boston Township Relocation	1
26	Mound Road Relocation- Phase 3	0
27	Bridging North America	0
28	Pulte - Arbor Glen OH Relocation	0
29	Clifford St. Re-route	-
30	University of MI/ Olympia Development of M	(1)
31	Mound Road Relocation- Phase 1	(24)
32	Mound Road Relocation- Phase 2	(241)
33	**Total Historical Test Year's Relocation Projects**	**24,923**

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Distribution Plant - Resilience and Hardening
($000)

Case No.: U-22046
Exhibit: Revised A-12
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Witness: J. E. Robinson
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	(a)	(b)	(c)	(d)	(e)	(f)	(g)
			Capital Expenditures				
		Historical	Projected Bridge Period			Test Year	
Line No.	Description	12 mos. ended 12/31/2025	12 mos. ending 12/31/2026	2 mos. ending 2/28/2027	14 mos. ending 2/28/2027	12 mos. ending 2/29/2028	In Service Year
1	**Resilience and Hardening**						
2	4.8 kV Hardening	100,354	82,000	10,228	92,228	51,142	Annual
3	Small Wire Replacement Program	-	10,000	1,667	11,667	10,000	Annual
4	Pole and Pole Top Maintenance and Modernization (PTMM)	107,678	-	10,567	10,567	115,633	Annual
5	Frequent Outage Program (CEMI)	34,019	41,880	3,750	45,630	22,500	Annual
6	Frequent Outage: Wolfhill	-	250	500	750	4,167	2028
7	Mobile Fleet Program	1,657	5,000	667	5,667	3,583	Annual
8	Pilot: Strategic and Service Undergrounding	2,184	6,000	1,333	7,333	6,667	Annual
9	Substation Risk: Apache	2,585	1,900	-	1,900	-	2026
10	Substation Risk: Belleville Switchgear Decommission	635	-	-	-	-	2025
11	Substation Risk: Chestnut	3,683	2,000	603	2,603	3,017	2027
12	Substation Risk: Drexel	987	-	-	-	-	2025
13	Substation Risk: Flood Defense Program	2,906	1,200	-	1,200	-	2026
14	Substation Risk: Hood	4,519	950	-	950	-	2026
15	Substation Risk: Lancaster	26	2,500	1,042	3,542	5,500	2028
16	Substation Risk: McGraw	17,910	4,760	-	4,760	-	2026
17	Substation Risk: Savage Switchgear Replacement	-	125	250	375	2,250	2029
18	Substation Risk: Seville	-	-	-	-	17	2031
19	Substation Risk: Sterling	-	-	33	33	500	2031
20	Substation Risk: Waterman	328	240	-	240	-	2026
21	Batteries and Chargers Replacement Program	2,810	3,030	505	3,535	3,030	Annual
22	Breaker Replacement Program	(286)	-	-	-	3,333	Annual
23	Disconnect and Switcher Replacement	5,135	4,900	817	5,717	4,900	Annual
24	Substation Regulator Replacement	867	1,000	167	1,167	1,000	Annual
25	40 kV: Automatic Pole-Top Switch	5,143	5,000	1,083	6,083	6,833	Annual
26	SCADA Pole-Top Device Replacement	2,066	2,038	433	2,471	3,025	Annual
27	Steel Pole Highway Crossings	642	1,000	333	1,333	2,000	Annual
28	Cable Replacement Program	15,961	13,500	3,833	17,333	24,500	Annual
29	URD Replacement Program	810	-	-	-	3,333	Annual
30	Station Upgrade: 120kV Relays Upgrade for ITC Projects	2,992	3,000	583	3,583	3,500	Annual
31	Station Upgrade: Navarre	134	-	83	83	750	2029
32	Station Upgrade: Northeast (Relay Replacement)	(68)	-	-	-	-	2025
33	**Total Resilience and Hardening Projects and Programs**	**315,677**	**192,273**	**38,478**	**230,751**	**281,180**	
34	**Category Summary**						
35	4.8 kV Hardening (Line 2)	100,354	82,000	10,228	92,228	51,142	
36	Conductor Replacement (Line 3)	-	10,000	1,667	11,667	10,000	
37	Pole and Pole Top Maintenance and Modernization (Line 4)	107,678	-	10,567	10,567	115,633	
38	Frequent Outage (Sum Lines 5 thru 6)	34,019	42,130	4,250	46,380	26,667	
39	Restoration Readiness and Community Resilience (Line 7)	1,657	5,000	667	5,667	3,583	
40	Undergrounding (Line 8)	2,184	6,000	1,333	7,333	6,667	
41	Substation Risk (Sum Lines 9 thru 20)	33,578	13,675	1,928	15,603	11,283	
42	System Equipment Replacement (Sum Lines 21 thru 32)	36,206	33,468	7,838	41,306	56,205	
43	**Total Resilience and Hardening Projects and Programs**	**315,677**	**192,273**	**38,478**	**230,751**	**281,180**	

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Distribution Plant - Redesign and Modernization
($000)

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Capital Expenditures					
		Historical	Projected Bridge Period			Test Year	
Line No.	Description	12 mos. ended 12/31/2025	12 mos. ending 12/31/2026	2 mos. ending 2/28/2027	14 mos. ending 2/28/2027	12 mos. ending 2/29/2028	In Service Year
1	**Redesign and Modernization**						
2	4.8 kV CC: Almont Relief and Circuit Conversion (Midas)	827	835	-	835	-	2026
3	4.8 kV CC: Ann Arbor AC Network Conversion	1,038	5,000	1,833	6,833	12,917	2031
4	4.8 kV CC: Belleville Substation and Circuit Conversion	(0)	275	250	525	2,000	2031
5	4.8 kV CC: Birmingham Decommissioning and Circuit Conversion	114	4,176	-	4,176	-	2026
6	4.8 kV CC: Buckler Circuit Conversion	3,197	3,900	500	4,400	2,500	2027
7	4.8 kV CC: Calla Circuit Conversion and Phase 2	2	4,000	583	4,583	2,917	2027
8	4.8 kV CC: Camden Decommissioning	129	1,410	22	1,432	108	2027
9	4.8 kV CC: Cortland / Oakman / Linwood Consolidation	377	-	-	-	-	2025
10	4.8 kV CC: Fairgrove	82	-	-	-	583	2028
11	4.8 kV CC: GRFIN & WMSTN Conversions	(166)	-	-	-	-	2025
12	4.8 kV CC: Grosse Pointe Substation and Circuit Conversion - South	34	1,000	709	1,709	5,876	2031
13	4.8 kV CC: Hawthorne Relief and Circuit Conversion	5,048	13,367	1,984	15,351	13,454	2031
14	4.8 kV CC: Hemlock Decommissioning and Circuit Conversion	487	775	883	1,658	6,417	2031
15	4.8 kV CC: Hilton Substation and Circuit Conversion - Phase 2	1,311	6,300	3,208	9,508	18,250	2031
16	4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade) - 8098 & 8632	2,923	12,000	2,750	14,750	17,417	2030
17	4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade) - 9221 & 9601	-	-	17	17	333	2031
18	4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade) - Above Grade	48	-	-	-	-	2025
19	4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade) - Below Grade	50	-	-	-	-	2025
20	4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade) - System Conduit	35	8,600	350	8,950	1,750	2027
21	4.8 kV CC: Lapeer - Elba Expansion and Circuit Conversion (Apollo)	95	-	-	-	-	2025
22	4.8 kV CC: McKinstry Sub Decommission	29	-	-	-	-	2025
23	4.8 kV CC: Melvindale	289	2,315	-	2,315	-	2026
24	4.8 kV CC: New Baltimore	2,247	8,500	2,600	11,100	15,292	2030
25	4.8 kV CC: Pinegrove Substation Relocation and Conversion	15,091	9,324	825	10,149	4,125	2027
26	4.8 kV CC: Pinegrove Substation Relocation and Conversion CIAC	(5,702)	-	-	-	-	2027
27	4.8 kV CC: Pittsfield Substation and Circuit Conversion	118	200	208	408	2,542	2030
28	4.8 kV CC: Quincy Conversion	(68)	-	-	-	-	2025
29	4.8 kV CC: Rochester Decommissioning and Tienken Relief	295	3,661	250	3,911	2,558	2031
30	4.8 kV CC: SCOTN	195	45	-	45	-	2026
31	4.8 kV CC: Unionville DC 301 B1 Conversion	977	519	-	519	-	2026
32	4.8 kV CC: White Lake Decommissioning and Circuit Conversion	75	-	-	-	250	2031
33	4.8 kV CC: Zenon Substation and Circuit Conversion - Phase 2	-	150	275	425	3,625	2031
34	4.8 kV CC: ISO Conversion Program	9,064	7,941	-	7,941	-	Annual
35	CODI: Alfred Substation Expansion	2,428	7,600	-	7,600	-	2026
36	CODI: CATO Substation Expansion	4,568	2,030	83	2,113	1,542	2031
37	CODI: Charlotte Network Upgrade	4,670	6,400	700	7,100	3,500	2027
38	CODI: Garfield Network Upgrade	10,680	6,000	1,083	7,083	6,683	2029
39	CODI: Garfield Radial (Midtown Circuits)	1,182	9,000	2,417	11,417	13,333	2028
40	CODI: Garfield Radial (Alfred Circuits)	1,441	2,000	1,667	3,667	11,550	2031
41	CODI: Garfield UG Radial Conversion	-	-	17	17	167	2031

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Distribution Plant - Redesign and Modernization
($000)

Case No.: U-22046
Exhibit: Revised A-12
Schedule: Revised B5.4
Witness: R. M. Stowe

(a)		(b)	(c)	(d)	(e)	(f)	(g)
		Capital Expenditures					
		Historical	Projected Bridge Period			Test Year	
Line No.	Description	12 mos. ended 12/31/2025	12 mos. ending 12/31/2026	2 mos. ending 2/28/2027	14 mos. ending 2/28/2027	12 mos. ending 2/29/2028	In Service Year
42	CODI: Howard Conversion	373	16,000	1,467	17,467	8,550	2030
43	CODI: Islandview Substation - Phase 1	32	-	-	-	-	2025
44	CODI: Islandview Substation - Phase 2	1,199	10,800	-	10,800	-	2026
45	CODI: Islandview Substation - Phase 3	1,382	12,230	45	12,275	225	2027
46	CODI: Islandview Substation - DC9620 & DC9636	389	9,500	2,750	12,250	16,000	2028
47	CODI: Islandview Substation - PL9671-ST & PL9664-ST	-	-	17	17	167	2031
48	CODI: Kent/Gibson Conversion - CORKT8562, CORKT8507	-	-	-	-	17	2031
49	CODI: Kent/Gibson Conversion - Kent Decommissioning	46	-	58	58	742	2029
50	CODI: Kent/Gibson Conversion - Phase 1	2,082	16,000	1,950	17,950	9,750	2027
51	CODI: Midtown Substation Expansion	189	406	-	406	-	2026
52	CODI: Targeted Network Secondary Cable Replacement	3,403	3,000	-	3,000	-	Annual
53	8.3 kV CC: Pontiac Overhead Conversion	3,732	13,080	1,207	14,287	7,828	2029
54	8.3 kV CC: Pontiac Underground Conversion	1,058	2,000	417	2,417	2,583	2029
55	Pontiac Vaults	995	350	-	350	-	Annual
56	System Loading: Brown City	1,624	5,500	383	5,883	1,917	2031
57	System Loading: Carleton	1	-	-	-	-	2025
58	System Loading: Cody	1,060	2,225	258	2,483	1,750	2028
59	System Loading: Goodison	1,415	1,500	783	2,283	6,583	2030
60	System Loading: Grenada	2,473	7,500	2,050	9,550	12,450	2030
61	System Loading: Kings Pointe	261	-	-	-	-	2031
62	System Loading: Lark/Spruce	2,695	700	-	700	-	2031
63	System Loading: Mohican	8	250	-	250	-	2026
64	System Loading: Otsego/Capac/Shaw	6	-	167	167	1,083	2031
65	System Loading: Port Sanilac	956	500	-	500	-	2026
66	System Loading: Richmond/Armada	3,649	3,800	458	4,258	3,625	2031
67	System Loading: Spokane/Seneca	1,770	1,050	583	1,633	4,583	2030
68	System Loading: Wixom	4,158	9,545	1,417	10,962	8,342	2030
69	Ann Arbor System Improvements: Argo 40kV Reconfiguration	3,071	3,000	667	3,667	3,500	2028
70	Subtransmission Redesign & Rebuild: 40kV Capacitor Banks at Armada and Adair	233	-	-	-	-	2025
71	Subtransmission Redesign & Rebuild: Badax Transformer 102 Addition	7,353	1,025	-	1,025	-	2026
72	Subtransmission Redesign & Rebuild: Boyne	1,290	573	-	573	-	2026
73	Subtransmission Redesign & Rebuild: Cortland Station Expansion	5,720	200	92	292	823	2031
74	Subtransmission Redesign & Rebuild: DUNN Station	-	1,000	83	1,083	417	2027
75	Subtransmission Redesign & Rebuild: Maxwell Amherst	51	-	-	-	-	2025
76	Subtransmission Redesign & Rebuild: Reverse Power Relay Scheme Program	23	1,000	167	1,167	1,000	Annual
77	Subtransmission Redesign & Rebuild: Sandusky Transformer 101 Breaker	1,712	1,550	-	1,550	-	2026
78	Subtransmission Redesign & Rebuild: Small Projects & Reserve	40	-	-	-	-	Annual
79	Subtransmission Redesign & Rebuild: Tie 4105 Phase 1	105	-	-	-	-	2025
80	Subtransmission Redesign & Rebuild: Tie 4105 Phase 3	(8)	-	-	-	-	2025
81	Subtransmission Redesign & Rebuild: Tie 810	12,971	1,420	-	1,420	-	2026

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Distribution Plant - Redesign and Modernization
($000)

Case No.: U-22046
Exhibit: Revised A-12
Schedule: Revised B5.4
Witness: R. M. Stowe

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Capital Expenditures					
		Historical	Projected Bridge Period			Test Year	
Line No.	Description	12 mos. ended 12/31/2025	12 mos. ending 12/31/2026	2 mos. ending 2/28/2027	14 mos. ending 2/28/2027	12 mos. ending 2/29/2028	In Service Year
82	Subtransmission Redesign & Rebuild: Transformer High Side Protection Program	1,516	3,500	1,083	4,583	6,500	Annual
83	Subtransmission Redesign & Rebuild: Trunk 2308	7,421	400	-	400	-	2026
84	Subtransmission Redesign & Rebuild: Trunk 2419	28	-	-	-	-	2025
85	Subtransmission Redesign & Rebuild: Trunk 3509	358	1,800	-	1,800	-	2026
86	Subtransmission Redesign & Rebuild: Trunk 4217	55	-	-	-	-	2025
87	Subtransmission Redesign & Rebuild: Trunk 4245	2,245	-	-	-	-	2027
88	TCHPP Switchyard Upgrades	875	-	-	-	-	2025
89	NWA: Battery Trailer	426	155	-	155	-	2026
90	NWA: EV Charging Demonstration	1,156	1,200	121	1,321	713	2028
91	NWA: Fisher Load Relief	787	-	-	-	-	2025
92	NWA: Omega Load Relief	652	-	-	-	-	2025
93	NWA: O'Shea Energy Storage	215	-	-	-	-	2025
94	NWA: Port Austin Load Relief	419	100	67	167	333	2027
95	NWA: Veridian	1,186	750	-	750	-	2026
96	**Total Redesign and Modernization Projects and Programs**	**148,068**	**260,931**	**39,504**	**300,435**	**249,169**	
97	**Category Summary**						
98	4.8 kV CC (Sum lines 2 thru 33)	29,177	86,351	17,248	103,599	112,913	
99	4.8 kV CC: ISO Conversion Program (Line 34)	9,064	7,941	-	7,941	-	
100	CODI (Sum lines 35 thru 52)	34,065	100,966	12,253	113,219	72,225	
101	8.3 kV CC (Sum lines 53 thru 55)	5,785	15,430	1,624	17,054	10,412	
102	4.8 kV and 8.3 kV Conversion (Sum lines 2 thru 55)	78,091	210,688	31,125	241,813	195,550	
103	System Loading (Sum lines 56 thru 68)	20,076	32,570	6,100	38,670	40,333	
104	Subtransmission Redesign and Rebuild (Sum lines 69 thru 88)	45,060	15,468	2,092	17,560	12,240	
105	NWAs (Sum lines 89 thru 95)	4,841	2,205	188	2,393	1,046	
	Total Redesign and Modernization Projects and Programs	**148,068**	**260,931**	**39,504**	**300,435**	**249,169**	

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Distribution Plant - Technology and Automation
($000)

Case No.: U-22046
Exhibit: Revised A-12
Schedule: Revised B5.4
Witness: S. P. Rademacher

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Capital Expenditures					
		Historical	Projected Bridge Period			Test Year	
Line No.	Description	12 mos. ended 12/31/2025	12 mos. ending 12/31/2026	2 mos. ending 2/28/2027	14 mos. ending 2/28/2027	12 mos. ending 2/29/2028	In Service Year
1	**Technology and Automation**						
2	ADMS/GMS HARDWARE	-	1,900	958	2,858	5,508	Annual
3	ADMS Enhancements	6,037	8,000	2,626	10,626	14,570	Annual
4	FLISR Implementation	3,923	4,400	1,067	5,467	6,233	Annual
5	ADMS: DMS/OMS Mobile Tool	2,253	5,301	108	5,409	542	2027
6	ADMS: Network Management System	2,168	2,000	-	2,000	-	Annual
7	Distribution Automation	68,885	-	16,667	16,667	106,667	Annual
8	Substransmission SCADA	-	-	-	-	1,000	2031
9	CVR/VVO	2,856	2,000	500	2,500	3,417	Annual
10	Distribution Sensing and Monitoring (incldg Line Sensors)	2,830	1,000	333	1,333	2,000	Annual
11	SCADA Communication Equipment Replacement	-	1,132	189	1,321	1,223	2029
12	DER Integration	5,392	5,400	842	6,242	4,850	Annual
13	DER Control	270	290	48	338	290	Annual
14	Asset Failure Analytics	-	1,000	173	1,173	1,047	Annual
15	Image Acquisition Platforms	-	-	599	599	3,957	2030
16	Automation Configuration and Test Record Database	0	1,245	-	1,245	-	2026
17	Distribution SCADA Historian	-	4,742	-	4,742	-	Annual
18	Meter Improvements	821	1,400	-	1,400	-	Annual
19	Customer Power Status Visibility	7,647	7,800	-	7,800	-	Annual
20	Other Modernize Grid Management	727	1,750	-	1,750	-	2026
21	SOC Phone and Radio Dispatch	-	1,200	-	1,200	-	2026
22	Operational Technology and Error Free Communication	1,099	500	-	500	-	2026
23	Substation Cybersecurity	695	-	-	-	-	Annual
24	Customer Agreement Processing (CAP) System replacement	-	-	317	317	1,900	2028
25	Power Quality Analysis Program	254	400	83	483	483	Annual
26	Customer Power Quality Monitoring & Issue Investigation	-	-	151	151	858	2028
27	Load Forecasting & Analytics	4,202	5,241	1,377	6,618	7,659	Annual
28	Interconnection Process Enablement	2,612	2,472	449	2,921	2,677	Annual
29	Hosting Capacity Enablement	319	400	50	450	333	Annual
30	Substation Design Tool Upgrades	1,059	1,000	425	1,425	2,540	Annual

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Distribution Plant - Technology and Automation
($000)

Case No.: U-22046
Exhibit: Revised A-12
Schedule: Revised B5.4
Witness: S. P. Rademacher

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
			Capital Expenditures				
		Historical	Projected Bridge Period			Test Year	
Line No.	Description	12 mos. ended 12/31/2025	12 mos. ending 12/31/2026	2 mos. ending 2/28/2027	14 mos. ending 2/28/2027	12 mos. ending 2/29/2028	In Service Year
31	Design Tool Automation	-	1,200	353	1,553	2,067	2030
32	Distribution Planning	(0)	-	-	-	-	2025
33	Digital Construction Management	-	-	345	345	2,098	2029
34	External Crew Efficiency	7,685	3,100	617	3,717	3,450	2028
35	Field Service Management	985	1,250	83	1,333	417	2029
36	Mobile Timesheets	-	1,400	217	1,617	1,167	2028
37	Vegetation Management Replatform	-	3,200	258	3,458	1,375	2028
38	Field Work Execution & Workforce Management Enhancements	-	-	-	-	500	2030
39	Primary Service Orders Replatform	1,356	-	-	-	-	2025
40	Substation Reporting and Process Enhancements	0	-	-	-	-	2025
41	Work Management & Scheduling Upgrades	(185)	-	-	-	-	2025
42	Cable Failure Analytics	981	-	-	-	-	2025
43	ESRI Utility Network Proof of Concept	571	-	-	-	-	2025
44	ESRI Utility Network Model Upgrade	-	5,509	918	6,427	5,509	2029
45	Telecom & Radio Systems Upgrade	-	-	-	-	112	2030
46	Enterprise Service Bus Upgrade	-	-	342	342	1,893	2029
47	Asset Management Upgrades	90	-	-	-	-	2025
48	Enhance and expand cybersecurity	739	1,078	326	1,404	1,963	2031
49	Mobile Equipment Replacement	-	1,000	167	1,167	1,008	Annual
50	Mobile Technology	(325)	-	-	-	-	2025
51	Mobile tools expansion	2,941	2,210	342	2,552	2,050	2028
52	**Total Technology and Automation Projects and Programs**	**128,885**	**80,520**	**30,928**	**111,448**	**191,363**	
53	**Category Summary**						
54	Advanced Distribution Management System (Sum Lines 2 thru 6)	14,381	21,601	4,759	26,360	26,853	
55	Distribution Automation (Line 7)	68,885	-	16,667	16,667	106,667	
56	Subtransmission SCADA (Line 8)	-	-	-	-	1,000	
57	Grid Technology (Sum Lines 9 thru 13)	11,348	9,822	1,912	11,734	11,780	
58	Asset Condition Monitoring Technology (Sum Lines 14 thru 15)	-	1,000	773	1,773	5,004	
59	OT - Grid Management (Sum Lines 16 thru 23)	10,989	18,637	-	18,637	-	
60	OT - Distribution Planning (Sum Lines 24 thru 32)	8,445	10,713	3,204	13,917	18,517	
61	OT - Work Management & Scheduling (Sum Lines 33 thru 41)	9,841	8,950	1,520	10,470	9,007	
62	OT - Asset Management (Sum Lines 42 thru 47)	1,641	5,509	1,260	6,769	7,514	
63	OT - Mobile Technology (Sum Lines 48 thru 51)	3,355	4,288	834	5,122	5,021	
61	Operational Technology (Sum Lines 16 thru 51)	34,271	48,097	6,817	54,914	40,059	
62	**Total Technology and Automation Projects and Programs**	**128,885**	**80,520**	**30,928**	**111,448**	**191,363**	

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Distribution Plant - Grid Edge and Distributed Intelligence
($000)

Case No.: U-22046
Exhibit: Revised A-12
Schedule: Revised B5.4
Witness: S. P. Rademacher
P. Sharma 2/

	(a)		(b)	(c)	(d)	(e)	(f)	(g)
			Capital Expenditures					
			Historical	Projected Bridge Period			Test Year	
Line No.	Description		12 mos. ended 12/31/2025	12 mos. ending 12/31/2026	2 mos. ending 2/28/2027	14 mos. ending 2/28/2027	12 mos. ending 2/29/2028	In Service Year
1	**Grid Edge and Distributed Intelligence**							
2	Next-Gen AMI and Distributed Intelligence		-	2,400	483	2,883	3,800	Annual
3	DERMS		15	2,800	850	3,650	4,817	2030
4	Grid Automation Telecommunications		6,810	10,000	2,000	12,000	12,000	Annual
5	Last-Mile Communications	2/	-	-	-	-	7,000	Annual
6	**Total Grid Edge and Distributed Intelligence Projects and Programs**		**6,825**	**15,200**	**3,333**	**18,533**	**27,617**	

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Allowance for Funds Used During Construction (AFUDC)
Distribution Operations
($000)

Case No.: U-22046
Exhibit: Revised A-12
Schedule: Revised B5.4
Witness: B. L. Hill 1/
J. E. Robinson 2/
R. M. Stowe 3/
S. P. Rademacher 4/

Line No.	(a) Description		(b) Adjusted Historical 12 mos. ended 12/31/2025	(c) Projected 12 mos. ending 2/29/2028	
1	**Base Capital Programs:**				
2	OPEN	1/	-	-	
3	Other Routine Base Capital Programs	1/	4,366	4,501	5/
4	**Subtotal Base Capital Programs**		**4,366**	**4,501**	
5	**Strategic Capital Programs:**				
6	Infrastructure Resilience and Hardening	2/	3,341	2,958	5/
7	Infrastructure Redesign and Modernization:				
8	OPEN	3/	-	-	
9	Other Redesign and Modernization	3/	10,679	17,865	5/
10	Grid Edge & Distributed Intelligence	4/	152	612	5/
11	Technology and Automation	4/	962	1,419	5/
12	**Subtotal Strategic Capital Programs**		**15,134**	**22,854**	
13	**Total AFUDC - Distribution Operations**		**19,500**	**27,355**	6/

1/ Sponsored by Company Witness B. L. Hill: Base Capital Programs
2/ Sponsored by Company Witness J. E. Robinson: Infrastructure Resilience and Hardening
3/ Sponsored by Company Witness R. M. Stowe: Infrastructure Redesign and Modernization
4/ Sponsored by Company Witness S. P. Rademacher: Technology and Automation
5/ AFUDC estimates for platform are developed at a high level based on historical trend
6/ The projected AFUDC amounts are based on the authorized U-21860 of 5.64%

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Removal Costs, Plant in Service and CWIP
Distribution Plant
($000)

	(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
Line No.	Description		In-Service Assumption	Capital Expenditures (including Removal Costs)				Est. % Removal	Activity Accum. Depr. - Removal Costs			Activity Plant in Service			Activity CWIP - Net Additions/(Unitization)		
				12 mos. ended 12/31/2025	12 mos. ending 12/31/2026	2 mos. ending 2/28/2027	12 mos. ending 2/29/2028		12 mos. ending 12/31/2026 *col (d)x(g)*	2 mos. ending 2/28/2027 *col (e)x(g)*	12 mos. ending 2/29/2028 *col (f)x(g)*	12 mos. ending 12/31/2026	2 mos. ending 2/28/2027	12 mos. ending 2/29/2028	12 mos. ending 12/31/2026 *col (d)-(h)-(k)*	2 mos. ending 2/28/2027 *col (e)-(i)-(l)*	12 mos. ending 2/29/2028 *col (f)-(j)-(m)*
	Base Capital Programs																
1	Emergent Replacements	1/	Annual	534,675	560,654	95,044	570,877	15%	84,098	14,257	85,632	476,556	80,787	485,245	-	-	-
2	Connections & New Load:																
3	I-375 Relocations	1/	Dec-26	4,793	5,000	-	-	15%	750	-	-	8,324	-	-	(4,074)	-	-
4	Substation Physical Security	1/	Dec-23	(148)	-	-	-	15%	-	-	-	-	-	-	-	-	-
5	Public Lighting Department Project	1/	Dec-23	26	-	-	-	15%	-	-	-	-	-	-	-	-	-
6	Other Connections and New Load	1/	Annual	375,360	361,596	62,480	377,732	15%	54,239	9,372	56,660	307,357	53,108	321,072	-	-	-
7	Connections Sub-Total			380,032	366,596	62,480	377,732		54,989	9,372	56,660	315,681	53,108	321,072	(4,074)	-	-
8	**Infrastructure Resilience and Hardening**																
9	4.8 kV Hardening	2/	Annual	100,354	82,000	10,228	51,142	15%	12,300	1,534	7,671	69,700	8,694	43,470	-	-	-
10	Small Wire Replacement Program	2/	Annual	-	10,000	1,667	10,000	15%	1,500	250	1,500	8,500	1,417	8,500	-	-	-
11	Pole and Pole Top Maintenance and Modernization (PTMM)	2/	Annual	107,678	-	10,567	115,633	15%	-	1,585	17,345	-	8,982	98,288	-	-	-
12	Frequent Outage Program (CEMI)	2/	Annual	34,019	41,880	3,750	22,500	15%	6,282	563	3,375	35,598	3,188	19,125	-	-	-
13	Frequent Outage: Wolfhill	2/	Dec-28	-	250	500	4,167	15%	38	75	625	-	-	-	213	425	3,542
14	Mobile Fleet Program	2/	Annual	1,657	5,000	667	3,583	15%	750	100	538	4,250	567	3,046	-	-	-
15	Pilot: Strategic and Service Undergrounding	2/	Annual	2,184	6,000	1,333	6,667	15%	900	200	1,000	5,100	1,133	5,667	-	-	-
16	Substation Risk: Apache	2/	Dec-26	2,585	1,900	-	-	15%	285	-	-	3,812	-	-	(2,197)	-	-
17	Substation Risk: Belleville Switchgear Decommission	2/	Dec-25	635	-	-	-	15%	-	-	-	-	-	-	-	-	-
18	Substation Risk: Chestnut	2/	Dec-27	3,683	2,000	603	3,017	15%	300	91	453	-	-	7,907	1,700	513	(5,343)
19	Substation Risk: Drexel	2/	Dec-25	987	-	-	-	15%	-	-	-	-	-	-	-	-	-
20	Substation Risk: Flood Defense Program	2/	Dec-26	2,906	1,200	-	-	15%	180	-	-	3,490	-	-	(2,470)	-	-
21	Substation Risk: Hood	2/	Dec-26	4,519	950	-	-	15%	143	-	-	4,648	-	-	(3,841)	-	-
22	Substation Risk: Lancaster	2/	Dec-28	26	2,500	1,042	5,500	15%	375	156	825	-	-	-	2,125	885	4,675
23	Substation Risk: McGraw	2/	Dec-26	17,910	4,760	-	-	15%	714	-	-	19,270	-	-	(15,224)	-	-
24	Substation Risk: Savage Switchgear Replacement	2/	Dec-29	-	125	250	2,250	15%	19	38	338	-	-	-	106	213	1,913
25	Substation Risk: Seville	2/	Dec-31	-	-	-	17	15%	-	-	3	-	-	-	-	-	14
26	Substation Risk: Sterling	2/	Dec-31	-	-	33	500	15%	-	5	75	-	-	-	-	28	425
27	Substation Risk: Waterman	2/	Dec-26	328	240	-	-	15%	36	-	-	483	-	-	(279)	-	-
28	Batteries and Chargers Replacement Program	2/	Annual	2,810	3,030	505	3,030	15%	455	76	455	2,576	429	2,576	-	-	-
29	Breaker Replacement Program	2/	Annual	(286)	-	-	3,333	15%	-	-	500	-	-	2,833	-	-	-
30	Disconnect and Switcher Replacement	2/	Annual	5,135	4,900	817	4,900	15%	735	123	735	4,165	694	4,165	-	-	-
31	Substation Regulator Replacement	2/	Annual	867	1,000	167	1,000	15%	150	25	150	850	142	850	-	-	-
32	40 kV: Automatic Pole-Top Switch	2/	Annual	5,143	5,000	1,083	6,833	15%	750	163	1,025	4,250	921	5,808	-	-	-
33	SCADA Pole-Top Device Replacement	2/	Annual	2,066	2,038	433	3,025	15%	306	65	454	1,732	368	2,571	-	-	-
34	Steel Pole Highway Crossings	2/	Annual	642	1,000	333	2,000	15%	150	50	300	850	283	1,700	-	-	-
35	Cable Replacement Program	2/	Annual	15,961	13,500	3,833	24,500	15%	2,025	575	3,675	11,475	3,258	20,825	-	-	-
36	URD Replacement Program	2/	Annual	810	-	-	3,333	15%	-	-	500	-	-	2,833	-	-	-

	(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
Line No.	Description		In-Service Assumption		Capital Expenditures (including Removal Costs)			Est. % Removal	Activity Accum. Depr. - Removal Costs			Activity Plant in Service			Activity CWIP - Net Additions/(Unitization)		
36	Station Upgrade: 120kV Relays Upgrade for ITC Projects	2/	Annual	2,992	3,000	583	3,500	15%	450	88	525	2,550	496	2,975	-	-	-
37	Station Upgrade: Navarre	2/	Dec-29	134	-	83	750	15%	-	13	113	-	-	-	-	71	638
38	Station Upgrade: Northeast (Relay Replacement)	2/	Dec-25	(68)	-		-	15%	-	-	-	-	-	-	-	-	-
38	Resilience Sub-Total			315,677	192,273	38,478	281,180		28,841	5,772	42,177	183,299	30,572	233,140	(19,867)	2,135	5,863
39	**Infrastructure Redesign**																
40	4.8 kV CC: Almont Relief and Circuit Conversion (Midas)	3/	Dec-26	827	835	-	-	15%	125	-	-	1,413	-	-	(703)	-	-
41	4.8 kV CC: Ann Arbor AC Network Conversion	3/	Dec-31	1,038	5,000	1,833	12,917	15%	750	275	1,938	-	-	-	4,250	1,558	10,979
42	4.8 kV CC: Belleville Substation and Circuit Conversion	3/	Dec-31	(0)	275	250	2,000	15%	41	38	300	-	-	-	234	213	1,700
43	4.8 kV CC: Birmingham Decommissioning and Circuit Conversion	3/	Dec-26	114	4,176	-	-	15%	626	-	-	3,646	-	-	(97)	-	-
44	4.8 kV CC: Buckler Circuit Conversion	3/	Dec-27	3,197	3,900	500	2,500	15%	585	75	375	-	-	8,582	3,315	425	(6,457)
45	4.8 kV CC: Calla Circuit Conversion and Phase 2	3/	Dec-27	2	4,000	583	2,917	15%	600	88	438	-	-	6,377	3,400	496	(3,897)
46	4.8 kV CC: Camden Decommissioning	3/	Dec-27	129	1,410	22	108	15%	212	3	16	-	-	1,418	1,199	18	(1,326)
47	4.8 kV CC: Cortland / Oakman / Linwood Consolidation	3/	Dec-25	377	-	-	-	15%	-	-	-	-	-	-	-	-	-
48	4.8 kV CC: Fairgrove	3/	Dec-28	82	-	-	583	15%	-	-	88	-	-	-	-	-	496
49	4.8 kV CC: GRFIN & WMSTN Conversions	3/	Dec-25	(166)	-	-	-	15%	-	-	-	-	-	-	-	-	-
50	4.8 kV CC: Grosse Pointe Substation and Circuit Conversion - South	3/	Dec-31	34	1,000	709	5,876	15%	150	106	881	-	-	-	850	602	4,994
51	4.8 kV CC: Hawthorne Relief and Circuit Conversion	3/	Dec-31	5,048	13,367	1,984	13,454	15%	2,005	298	2,018	-	-	-	11,362	1,687	11,436
52	4.8 kV CC: Hemlock Decommissioning and Circuit Conversion	3/	Dec-31	487	775	883	6,417	15%	116	133	963	-	-	-	659	751	5,454
53	4.8 kV CC: Hilton Substation and Circuit Conversion - Phase 2	3/	Dec-31	1,311	6,300	3,208	18,250	15%	945	481	2,738	-	-	-	5,355	2,727	15,513
54	4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade) - 8098 & 8632	3/	Dec-30	2,923	12,000	2,750	17,417	15%	1,800	413	2,613	-	-	-	10,200	2,338	14,804
55	4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade) - 9221 & 9601	3/	Dec-31	-	-	17	333	15%	-	3	50	-	-	-	-	14	283
56	4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade) - Above Grade	3/	Dec-25	48	-	-	-	15%	-	-	-	-	-	-	-	-	-
57	4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade) - Below Grade	3/	Dec-25	50	-	-	-	15%	-	-	-	-	-	-	-	-	-
58	4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade) - System Conduit	3/	Dec-27	35	8,600	350	1,750	15%	1,290	53	263	-	-	9,125	7,310	298	(7,638)
59	4.8 kV CC: Lapeer - Elba Expansion and Circuit Conversion (Apollo)	3/	Dec-25	95	-	-	-	15%	-	-	-	-	-	-	-	-	-
60	4.8 kV CC: McKinstry Sub Decommission	3/	Dec-25	29	-	-	-	15%	-	-	-	-	-	-	-	-	-
61	4.8 kV CC: Melvindale	3/	Dec-26	289	2,315	-	-	15%	347	-	-	2,213	-	-	(245)	-	-
62	4.8 kV CC: New Baltimore	3/	Dec-30	2,247	8,500	2,600	15,292	15%	1,275	390	2,294	-	-	-	7,225	2,210	12,998
63	4.8 kV CC: Pinegrove Substation Relocation and Conversion	3/	Dec-27	15,091	9,324	825	4,125	15%	1,399	124	619	-	-	24,960	7,925	701	(21,454)
64	4.8 kV CC: Pinegrove Substation Relocation and Conversion CIAC	3/	Dec-27	(5,702)	-	-	-	15%	-	-	-	-	-	(4,847)	-	-	4,847
64	4.8 kV CC: Pittsfield Substation and Circuit Conversion	3/	Dec-30	118	200	208	2,542	15%	30	31	381	-	-	-	170	177	2,160
65	4.8 kV CC: Quincy Conversion	3/	Dec-25	(68)	-	-	-	15%	-	-	-	-	-	-	-	-	-
66	4.8 kV CC: Rochester Decommissioning and Tienken Relief	3/	Dec-31	295	3,661	250	2,558	15%	549	38	384	-	-	-	3,112	213	2,175
67	4.8 kV CC: SCOTN	3/	Dec-26	195	45	-	-	15%	7	-	-	204	-	-	(166)	-	-

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Removal Costs, Plant in Service and CWIP
Distribution Plant
($000)

	(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
Line No.	Description		In-Service Assumption		Capital Expenditures (including Removal Costs)			Est. % Removal	Activity Accum. Depr. - Removal Costs			Activity Plant in Service			Activity CWIP - Net Additions/(Unitization)		
68	4.8 kV CC: Unionville DC 301 B1 Conversion	3/	Dec-26	977	519	-	-	15%	78	-	-	1,272	-	-	(831)	-	-
69	4.8 kV CC: White Lake Decommissioning and Circuit Conversion	3/	Dec-31	75	-	-	250	15%	-	-	38	-	-	-	-	-	213
70	4.8 kV CC: Zenon Substation and Circuit Conversion - Phase 2	3/	Dec-31	-	150	275	3,625	15%	23	41	544	-	-	-	128	234	3,081
71	4.8 kV CC: ISO Conversion Program	3/	Annual	9,064	7,941	-	-	15%	1,191	-	-	6,750	-	-	-	-	-
72	CODI: Alfred Substation Expansion	3/	Dec-26	2,428	7,600	-	-	15%	1,140	-	-	8,524	-	-	(2,064)	-	-
73	CODI: CATO Substation Expansion	3/	Dec-31	4,568	2,030	83	1,542	15%	305	13	231	-	-	-	1,726	71	1,310
74	CODI: Charlotte Network Upgrade	3/	Dec-27	4,670	6,400	700	3,500	15%	960	105	525	-	-	12,979	5,440	595	(10,004)
75	CODI: Garfield Network Upgrade	3/	Dec-29	10,680	6,000	1,083	6,683	15%	900	163	1,003	-	-	-	5,100	921	5,681
76	CODI: Garfield Radial (Midtown Circuits)	3/	Dec-28	1,182	9,000	2,417	13,333	15%	1,350	363	2,000	-	-	-	7,650	2,054	11,333
77	CODI: Garfield Radial (Alfred Circuits)	3/	Dec-31	1,441	2,000	1,667	11,550	15%	300	250	1,733	-	-	-	1,700	1,417	9,818
78	CODI: Garfield UG Radial Conversion	3/	Dec-31	-	-	17	167	15%	-	3	25	-	-	-	-	14	142
79	CODI: Howard Conversion	3/	Dec-30	373	16,000	1,467	8,550	15%	2,400	220	1,283	-	-	-	13,600	1,247	7,268
80	CODI: Islandview Substation - Phase 1	3/	Dec-25	32	-	-	-	15%	-	-	-	-	-	-	-	-	-
81	CODI: Islandview Substation - Phase 2	3/	Dec-26	1,199	10,800	-	-	15%	1,620	-	-	10,199	-	-	(1,019)	-	-
82	CODI: Islandview Substation - Phase 3	3/	Dec-27	1,382	12,230	45	225	15%	1,835	7	34	-	-	11,800	10,396	38	(11,609)
83	CODI: Islandview Substation - DC9620 & DC9636	3/	Dec-28	389	9,500	2,750	16,000	15%	1,425	413	2,400	-	-	-	8,075	2,338	13,600
84	CODI: Islandview Substation - PL9671-ST & PL9664-ST	3/	Dec-31	-	-	17	167	15%	-	3	25	-	-	-	-	14	142
85	CODI: Kent/Gibson Conversion - CORKT8562, CORKT8507	3/	Dec-31	-	-	-	17	15%	-	-	3	-	-	-	-	-	14
86	CODI: Kent/Gibson Conversion - Kent Decommissioning	3/	Dec-29	46	-	58	742	15%	-	9	111	-	-	-	-	50	630
87	CODI: Kent/Gibson Conversion - Phase 1	3/	Dec-27	2,082	16,000	1,950	9,750	15%	2,400	293	1,463	-	-	25,314	13,600	1,658	(17,027)
88	CODI: Midtown Substation Expansion	3/	Dec-26	189	406	-	-	15%	61	-	-	506	-	-	(161)	-	-
89	CODI: Targeted Network Secondary Cable Replacement	3/	Annual	3,403	3,000	-	-	15%	450	-	-	2,550	-	-	-	-	-
90	8.3 kV CC: Pontiac Overhead Conversion	3/	Dec-29	3,732	13,080	1,207	7,828	15%	1,962	181	1,174	-	-	-	11,118	1,026	6,654
91	8.3 kV CC: Pontiac Underground Conversion	3/	Dec-29	1,058	2,000	417	2,583	15%	300	63	388	-	-	-	1,700	354	2,196
92	Pontiac Vaults	3/	Annual	995	350	-	-	15%	53	-	-	298	-	-	-	-	-
93	System Loading: Brown City	3/	Dec-31	1,624	5,500	383	1,917	15%	825	58	288	-	-	-	4,675	326	1,629
94	System Loading: Carleton	3/	Dec-25	1	-	-	-	15%	-	-	-	-	-	-	-	-	-
95	System Loading: Cody	3/	Dec-28	1,060	2,225	258	1,750	15%	334	39	263	-	-	-	1,891	220	1,488
96	System Loading: Goodison	3/	Dec-30	1,415	1,500	783	6,583	15%	225	118	988	-	-	-	1,275	666	5,596
97	System Loading: Grenada	3/	Dec-30	2,473	7,500	2,050	12,450	15%	1,125	308	1,868	-	-	-	6,375	1,743	10,583
98	System Loading: Kings Pointe	3/	Dec-31	261	-	-	-	15%	-	-	-	-	-	-	-	-	-
99	System Loading: Lark/Spruce	3/	Dec-31	2,695	700	-	-	15%	105	-	-	-	-	-	595	-	-
100	System Loading: Mohican	3/	Dec-26	8	250	-	-	15%	38	-	-	219	-	-	(7)	-	-
101	System Loading: Otsego/Capac/Shaw	3/	Dec-31	6	-	167	1,083	15%	-	25	163	-	-	-	-	142	921
102	System Loading: Port Sanilac	3/	Dec-26	956	500	-	-	15%	75	-	-	1,238	-	-	(813)	-	-

	(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
Line No.	Description		In-Service Assumption		Capital Expenditures (including Removal Costs)			Est. % Removal	Activity Accum. Depr. - Removal Costs			Activity Plant in Service			Activity CWIP - Net Additions/(Unitization)		
103	System Loading: Richmond/Armada	3/	Dec-31	3,649	3,800	458	3,625	15%	570	69	544	-	-	-	3,230	390	3,081
104	System Loading: Spokane/Seneca	3/	Dec-30	1,770	1,050	583	4,583	15%	158	88	688	-	-	-	893	496	3,896
105	System Loading: Wixom	3/	Dec-30	4,158	9,545	1,417	8,342	15%	1,432	213	1,251	-	-	-	8,113	1,204	7,090
106	Ann Arbor System Improvements: Argo 40kV Reconfiguration	3/	Dec-28	3,071	3,000	667	3,500	15%	450	100	525	-	-	-	2,550	567	2,975
107	Subtransmission Redesign & Rebuild: 40kV Capacitor Banks at Armada and Adair	3/	Dec-25	233	-	-	-	15%	-	-	-	-	-	-	-	-	-
108	Subtransmission Redesign & Rebuild: Badax Transformer 102 Addition	3/	Dec-26	7,353	1,025	-	-	15%	154	-	-	7,121	-	-	(6,250)	-	-
109	Subtransmission Redesign & Rebuild: Boyne	3/	Dec-26	1,290	573	-	-	15%	86	-	-	1,584	-	-	(1,096)	-	-
110	Subtransmission Redesign & Rebuild: Cortland Station Expansion	3/	Dec-31	5,720	200	92	823	15%	30	14	124	-	-	-	170	78	700
111	Subtransmission Redesign & Rebuild: DUNN Station	3/	Dec-27	-	1,000	83	417	15%	150	13	63	-	-	1,275	850	71	(921)
112	Subtransmission Redesign & Rebuild: Maxwell Amherst	3/	Dec-25	51	-	-	-	15%	-	-	-	-	-	-	-	-	-
113	Subtransmission Redesign & Rebuild: Reverse Power Relay Scheme Program	3/	Annual	23	1,000	167	1,000	15%	150	25	150	850	142	850	-	-	-
114	Subtransmission Redesign & Rebuild: Sandusky Transformer 101 Breaker	3/	Dec-26	1,712	1,550	-	-	15%	233	-	-	2,773	-	-	(1,455)	-	-
115	Subtransmission Redesign & Rebuild: Small Projects & Reserve	3/	Annual	40	-	-	-	15%	-	-	-	-	-	-	-	-	-
116	Subtransmission Redesign & Rebuild: Tie 4105 Phase 1	3/	Dec-25	105	-	-	-	15%	-	-	-	-	-	-	-	-	-
117	Subtransmission Redesign & Rebuild: Tie 4105 Phase 3	3/	Dec-25	(8)	-	-	-	15%	-	-	-	-	-	-	-	-	-
118	Subtransmission Redesign & Rebuild: Tie 810	3/	Dec-26	12,971	1,420	-	-	15%	213	-	-	12,233	-	-	(11,026)	-	-
119	Subtransmission Redesign & Rebuild: Transformer High Side Protection Program	3/	Annual	1,516	3,500	1,083	6,500	15%	525	163	975	2,975	921	5,525	-	-	-
120	Subtransmission Redesign & Rebuild: Trunk 2308	3/	Dec-26	7,421	400	-	-	15%	60	-	-	6,648	-	-	(6,308)	-	-
121	Subtransmission Redesign & Rebuild: Trunk 2419	3/	Dec-25	28	-	-	-	15%	-	-	-	-	-	-	-	-	-
122	Subtransmission Redesign & Rebuild: Trunk 3509	3/	Dec-26	358	1,800	-	-	15%	270	-	-	1,834	-	-	(304)	-	-
123	Subtransmission Redesign & Rebuild: Trunk 4217	3/	Dec-25	55	-	-	-	15%	-	-	-	-	-	-	-	-	-
124	Subtransmission Redesign & Rebuild: Trunk 4245	3/	Dec-27	2,245	-	-	-	15%	-	-	-	-	-	1,908	-	-	(1,908)
125	TCHPP Switchyard Upgrades	3/	Dec-25	875	-	-	-	15%	-	-	-	-	-	-	-	-	-
126	NWA: Battery Trailer	3/	Dec-26	426	155	-	-	15%	23	-	-	494	-	-	(362)	-	-
127	NWA: EV Charging Demonstration	3/	Dec-28	1,156	1,200	121	713	15%	180	18	107	-	-	-	1,020	103	606
128	NWA: Fisher Load Relief	3/	Dec-25	787	-	-	-	15%	-	-	-	-	-	-	-	-	-
129	NWA: Omega Load Relief	3/	Dec-25	652	-	-	-	15%	-	-	-	-	-	-	-	-	-
130	NWA: O'Shea Energy Storage	3/	Dec-25	215	-	-	-	15%	-	-	-	-	-	-	-	-	-
131	NWA: Port Austin Load Relief	3/	Dec-27	419	100	67	333	15%	15	10	50	-	-	781	85	57	(498)
132	NWA: Veridian	3/	Dec-26	1,186	750	-	-	15%	113	-	-	1,645	-	-	(1,008)	-	-
133	Redesign Sub-Total			148,068	260,931	39,504	249,169	15%	39,140	5,926	37,375	77,189	1,063	106,049	144,602	32,516	105,745
134	**Technology and Automation**																
135	ADMS/GMS HARDWARE	4/	Annual	-	1,900	958	5,508	0%	-	-	-	1,900	958	5,508	-	-	-
136	ADMS Enhancements	4/	Annual	6,037	8,000	2,626	14,570	0%	-	-	-	8,000	2,626	14,570	-	-	-

	(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
Line No.	Description		In-Service Assumption		Capital Expenditures (including Removal Costs)			Est. % Removal	Activity Accum. Depr. - Removal Costs			Activity Plant in Service			Activity CWIP - Net Additions/(Unitization)		
137	FLISR Implementation	4/	Annual	3,923	4,400	1,067	6,233	0%	-	-	-	4,400	1,067	6,233	-	-	-
138	ADMS: DMS/OMS Mobile Tool	4/	Dec-27	2,253	5,301	108	542	0%	-	-	-	-	-	8,204	5,301	108	(7,663)
139	ADMS: Network Management System	4/	Annual	2,168	2,000	-	-	0%	-	-	-	2,000	-	-	-	-	-
140	Distribution Automation	4/	Annual	68,885	-	16,667	106,667	0%	-	-	-	-	16,667	106,667	-	-	-
141	Substransmission SCADA	4/	Dec-31	-	-	-	1,000	0%	-	-	-	-	-	-	-	-	1,000
142	CVR/VVO	4/	Annual	2,856	2,000	500	3,417	0%	-	-	-	2,000	500	3,417	-	-	-
143	Distribution Sensing and Monitoring (incldg Line Sensors)	4/	Annual	2,830	1,000	333	2,000	0%	-	-	-	1,000	333	2,000	-	-	-
144	SCADA Communication Equipment Replacement	4/	Dec-29	-	1,132	189	1,223	0%	-	-	-	-	-	-	1,132	189	1,223
145	DER Integration	4/	Annual	5,392	5,400	842	4,850	0%	-	-	-	5,400	842	4,850	-	-	-
146	DER Control	4/	Annual	270	290	48	290	0%	-	-	-	290	48	290	-	-	-
147	Asset Failure Analytics	4/	Annual	-	1,000	173	1,047	0%	-	-	-	1,000	173	1,047	-	-	-
148	Image Acquisition Platforms	4/	Dec-30	-	-	599	3,957	0%	-	-	-	-	-	-	-	599	3,957
149	Automation Configuration and Test Record Database	4/	Dec-26	0	1,245	-	-	0%	-	-	-	1,245	-	-	(0)	-	-
150	Distribution SCADA Historian	4/	Annual	-	4,742	-	-	0%	-	-	-	4,742	-	-	-	-	-
151	Meter Improvements	4/	Annual	821	1,400	-	-	0%	-	-	-	1,400	-	-	-	-	-
152	Customer Power Status Visibility	4/	Annual	7,647	7,800	-	-	0%	-	-	-	7,800	-	-	-	-	-
153	Other Modernize Grid Management	4/	Dec-26	727	1,750	-	-	0%	-	-	-	2,477	-	-	(727)	-	-
154	SOC Phone and Radio Dispatch	4/	Dec-26	-	1,200	-	-	0%	-	-	-	1,200	-	-	-	-	-
155	Operational Technology and Error Free Communication	4/	Dec-26	1,099	500	-	-	0%	-	-	-	1,599	-	-	(1,099)	-	-
156	Substation Cybersecurity	4/	Annual	695	-	-	-	0%	-	-	-	-	-	-	-	-	-
157	Customer Agreement Processing (CAP) System replacement	4/	Dec-28	-	-	317	1,900	0%	-	-	-	-	-	-	-	317	1,900
158	Power Quality Analysis Program	4/	Annual	254	400	83	483	0%	-	-	-	400	83	483	-	-	-
159	Customer Power Quality Monitoring & Issue Investigation	4/	Dec-28	-	-	151	858	0%	-	-	-	-	-	-	-	151	858
160	Load Forecasting & Analytics	4/	Annual	4,202	5,241	1,377	7,659	0%	-	-	-	5,241	1,377	7,659	-	-	-
161	Interconnection Process Enablement	4/	Annual	2,612	2,472	449	2,677	0%	-	-	-	2,472	449	2,677	-	-	-
162	Hosting Capacity Enablement	4/	Annual	319	400	50	333	0%	-	-	-	400	50	333	-	-	-
163	Substation Design Tool Upgrades	4/	Annual	1,059	1,000	425	2,540	0%	-	-	-	1,000	425	2,540	-	-	-
164	Design Tool Automation	4/	Dec-30	-	1,200	353	2,067	0%	-	-	-	-	-	-	1,200	353	2,067
165	Distribution Planning	4/	Dec-25	(0)	-	-	-	0%	-	-	-	-	-	-	-	-	-
166	Digital Construction Management	4/	Dec-29	-	-	345	2,098	0%	-	-	-	-	-	-	-	345	2,098
167	External Crew Efficiency	4/	Dec-28	7,685	3,100	617	3,450	0%	-	-	-	-	-	-	3,100	617	3,450
168	Field Service Management	4/	Dec-29	985	1,250	83	417	0%	-	-	-	-	-	-	1,250	83	417
169	Mobile Timesheets	4/	Dec-28	-	1,400	217	1,167	0%	-	-	-	-	-	-	1,400	217	1,167
170	Vegetation Management Replatform	4/	Dec-28	-	3,200	258	1,375	0%	-	-	-	-	-	-	3,200	258	1,375
171	Field Work Execution & Workforce Management Enhancements	4/	Dec-30	-	-	-	500	0%	-	-	-	-	-	-	-	-	500

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Removal Costs, Plant in Service and CWIP
Distribution Plant
($000)

Case: U-22046
Exhibit: Revised A-12
Schedule: Revised B5.4
Witnesses: B. L. Hill 1/, J. E. Robinson 2/,
R. M. Stowe 3/, S.P. Rademacher 4/ P. Sharma, 5/

	(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
Line No.	Description		In-Service Assumption		Capital Expenditures (including Removal Costs)			Est. % Removal	Activity Accum. Depr. - Removal Costs			Activity Plant in Service			Activity CWIP - Net Additions/(Unitization)		
172	Primary Service Orders Replatform	4/	Dec-25	1,356	-	-	-	0%	-	-	-	-	-	-	-	-	-
173	Substation Reporting and Process Enhancements	4/	Dec-25	0	-	-	-	0%	-	-	-	-	-	-	-	-	-
174	Work Management & Scheduling Upgrades	4/	Dec-25	(185)	-	-	-	0%	-	-	-	-	-	-	-	-	-
175	Cable Failure Analytics	4/	Dec-25	981	-	-	-	0%	-	-	-	-	-	-	-	-	-
176	ESRI Utility Network Proof of Concept	4/	Dec-25	571	-	-	-	0%	-	-	-	-	-	-	-	-	-
177	ESRI Utility Network Model Upgrade	4/	Dec-29	-	5,509	918	5,509	0%	-	-	-	-	-	-	5,509	918	5,509
178	Telecom & Radio Systems Upgrade	4/	Dec-30	-	-	-	112	0%	-	-	-	-	-	-	-	-	112
179	Enterprise Service Bus Upgrade	4/	Dec-29	-	-	342	1,893	0%	-	-	-	-	-	-	-	342	1,893
180	Asset Management Upgrades	4/	Dec-25	90	-	-	-	0%	-	-	-	-	-	-	-	-	-
181	Enhance and expand cybersecurity	4/	Dec-31	739	1,078	326	1,963	0%	-	-	-	-	-	-	1,078	326	1,963
182	Mobile Equipment Replacement	4/	Annual	-	1,000	167	1,008	0%	-	-	-	1,000	167	1,008	-	-	-
183	Mobile Technology	4/	Dec-25	(325)	-	-	-	0%	-	-	-	-	-	-	-	-	-
184	Mobile tools expansion	4/	Dec-28	2,941	2,210	342	2,050	0%	-	-	-	-	-	-	2,210	342	2,050
181	Technology Sub-Total			128,885	80,520	30,928	191,363	0%	-	-	-	56,966	25,764	167,487	23,554	5,163	23,876
182	**Grid Edge & Distributed Intelligence**																
183	Next-Gen AMI and Distributed Intelligence	4/	Annual	-	2,400	483	3,800	0%	-	-	-	2,400	483	3,800	-	-	-
184	DERMS	4/	12/1/2030	15	2,800	850	4,817	0%	-	-	-	-	-	-	2,800	850	4,817
185	Grid Automation Telecommunications	4/	Annual	6,810	10,000	2,000	12,000	0%	-	-	-	10,000	2,000	12,000	-	-	-
186	Last-Mile Communications	5/	Annual	-	-	-	7,000	0%	-	-	-	-	-	7,000	-	-	-
187	GE-DI Sub-Total		Annual	6,825	15,200	3,333	27,617	0%	-	-	-	12,400	2,483	22,800	2,800	850	4,817
188	Total Distribution Plant			1,514,161	1,476,174	269,768	1,697,938		207,068	35,326	221,844	1,122,091	193,778	1,335,794	147,015	40,664	140,300

1/ Sponsored by Company Witness B. L. Hill: Base Capital Programs
2/ Sponsored by Company Witness J. E. Robinson: Infrastructure Resilience and Hardening
3/ Sponsored by Company Witness R. M. Stowe: Infrastructure Redesign and Modernization
4/ Sponsored by Company Witness S. P. Rademacher: Technology and Automation and Grid Edge and Distributed Intelligence
5/ Sponsored by Company Witness P. Sharma: Last-Mile Communications

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-22046

PROOF OF SERVICE

STATE OF MICHIGAN)
) ss.
COUNTY OF WAYNE)

ESTELLA R. BRANSON states that on August 24, 2026, she served a copy of DTE Electric Company's Revised Direct Testimony and Exhibits of Witnesses Steven B. Ambrose, Jennifer E. Nelson, Quinn Gerdes, Allen J. Kryscynski, Joseph E. Robinson, and Jason D. De Stigter, in the above captioned matter, via electronic mail upon the persons listed on the attached service list.

Estella R. Branson

Digitally signed by Estella R. Branson
Date: 2026.08.24 19:43:14 -04'00'

ESTELLA R. BRANSON

MPSC Case No. U-22046
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