

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of Case No. U-22058
DTE Electric Company for approval
of special contracts and for other Volume No. 3
relief.

PUBLIC RECORD

CROSS-EXAMINATION

Proceedings held via Microsoft Teams in the
above-entitled matter before Theresa A.G. Staley, J.D.,
Administrative Law Judge with MOAHR, for the Michigan
Public Service Commission, Lansing, Michigan, on
Tuesday, June 30, 2026, at 9:10 a.m.

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Tuesday, June 30, 2026

At 9:10 a.m.

- - -

(Hearing resumes following adjournment of Tuesday,
April 28, 2026.)

JUDGE STALEY: We are on the record in
Case No. U-22058, captioned In the matter of the
application of DTE Electric Company for approval of
special contracts and related relief. Today is June 30,
2026, and this is the day and time set for cross-
examination in this matter. My name is Theresa Staley,
and I am the Administrative Law Judge assigned to this
matter by the Michigan Office of Administrative Hearings
and Rules.

May I have appearances for the record,
please, starting with the Company.

MR. JANISZEWSKI: Good morning, your
Honor. John Janiszewski and Andrea Hayden appearing on
behalf of DTE Electric Company.

JUDGE STALEY: Good morning. And Staff.

MR. SONNEVELDT: Good morning, your
Honor. Daniel Sonneveldt appearing on behalf of Staff,
and I'd also like to enter the appearances of Adam Cozort
and Amit Singh.

JUDGE STALEY: O.K. Good morning. The
Penn Reporting, LLC - lori.penn@yahoo.com

1 Attorney General.

2 MR. WOLLENZIEN: Good morning, your
3 Honor. Lucas Wollenzien appearing on behalf of Attorney
4 General Dana Nessel.

5 JUDGE STALEY: Good morning. NRDC,
6 Sierra Club, and MEC.

7 MS. HILLYER: Good morning, your Honor.
8 Holly Hillyer appearing on behalf of the Michigan
9 Environmental Council, Natural Resources Defense Council,
10 and Sierra Club.

11 JUDGE STALEY: All right. Good morning.

12 I will note for the record that Mr. Don
13 Keskey, who is counsel for Great Lakes Renewable Energy
14 Association, also known as GLREA, is on -- had a conflict
15 this morning and he is in another prehearing this morning
16 but will be joining us as soon as he finishes up with
17 that, and that was something that counsel to this matter
18 are aware of and I'm aware of, so he will be joining us
19 later.

20 Then IEI, MEIBC, and CEO.

21 MS. DUCKWORTH: Good morning, your Honor.
22 Katie Duckworth appearing on behalf of the Environmental
23 Law & Policy Center, the Ecology Center, the Union of
24 Concerned Scientists, and Vote Solar, collectively the
25 Clean Energy Organizations, CEO, as well as the Institute
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1 for Energy Innovation and Michigan Energy Innovation
2 Business Council, collectively MEI. I'd also like to
3 enter an appearance on behalf of my colleague, Daniel
4 Abrams.

5 JUDGE STALEY: All right. And then last
6 is Association for Businesses Advocating Tariff Equity,
7 also known as ABATE.

8 MR. CAMPBELL: Good morning, your Honor.
9 Steve Campbell, Clark Hill, PLC, on behalf of the
10 Association of Businesses Advocating Tariff Equity.

11 JUDGE STALEY: Good morning.

12 All right. Before going on the record, I
13 was advised that there will be cross-examination of the
14 Company Witness Foley as well as Company Witness is it
15 Bilyeu or "Belyeu"?

16 MR. JANISZEWSKI: Bilyeu, your Honor.

17 JUDGE STALEY: Bilyeu. O.K. And then
18 cross has been reserved for Company Witness Willis. I am
19 assuming that it will be NRDC, Sierra Club, and MEC will
20 go first with their cross-examination and then the
21 Attorney General thereafter. Is that acceptable?

22 MS. DUCKWORTH: I think we were going to
23 defer to the AG to go first, your Honor.

24 MR. WOLLENZIEN: That's correct by my
25 understanding as well, your Honor.

1 JUDGE STALEY: All right. So the
2 Attorney General will go first. Thank you. Then after
3 that, the remaining witnesses will be bound into the
4 record and exhibits admitted into the record.

5 So I need to start this morning with
6 motions, a motion for pro -- for admission pro hac vice
7 of Shannon Fisk on behalf of the Sierra Club and a motion
8 for pro hac vice of Helen Li on behalf of the Sierra
9 Club. I will note for the record that these motions were
10 filed on June 23, I received notification from the State
11 Bar of Michigan on June 22 of Shannon Fisk's eligibility
12 for admission pro hac vice, and on June 18, 2026, I
13 received a motion from the State Bar of Michigan
14 regarding Helen Li's eligibility for admission pro hac
15 vice. Does anyone have any objections to these motions?

16 All right. Hearing none, the motions for
17 admission pro hac vice of Shannon Fisk and Helen Li are
18 granted and I will have the administrative order
19 granting, or a ruling granting those accomplished today.

20 All right. With that, we will get
21 started, and I will turn this over to you,
22 Mr. Janiszewski, and you may call your first witness.

23 MR. JANISZEWSKI: Thank you, your Honor.
24 At this time, I'm going to hand off to Ms. Hayden, and I
25 would ask that we take a break of approximately three

1 minutes to get Mr. Foley situated in the hearing room.

2 JUDGE STALEY: All right, we can do that.

3 MR. JANISZEWSKI: Thank you.

4 (At 9:15 a.m., brief pause.)

5 JUDGE STALEY: Good morning, Mr. Foley.

6 MR. FOLEY: Good morning.

7 JUDGE STALEY: All right. I'll turn this
8 over to you, Ms. Hayden.

9 MS. HAYDEN: Thank you, your Honor. The
10 Company calls Mr. Neal Foley as its first witness.

11 COURT REPORTER: Mr. Foley, please raise
12 your right hand.

13 - - -

14 N E A L T. F O L E Y

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

18 COURT REPORTER: Thank you.

19 DIRECT EXAMINATION

20 BY MS. HAYDEN:

21 Q Mr. Foley, could you please state your name and business
22 address for the record.

23 A My name is Neal T. Foley, my business address is One
24 Energy Plaza, Detroit, Michigan 48226.

25 Q Did you file with the Commission a document titled the
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1 Qualifications and Revised Direct Testimony of Neal T.
2 Foley consisting of a cover sheet, 24 pages of questions
3 and answers?

4 A Yes.

5 Q Do you have any changes to make to that direct testimony?

6 A No.

7 Q Is that then the revised direct testimony that you are
8 adopting today?

9 A Yes.

10 Q Are you sponsoring any exhibits associated with your
11 revised direct testimony?

12 A Yes.

13 Q And for purposes of identification, are these two direct,
14 revised direct exhibits designated as Confidential
15 Exhibit A-16 and Confidential Exhibit A-18?

16 A Yes.

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

19 A No.

20 Q Did you also file with the Commission a document titled
21 the Rebuttal Testimony of Neal T. Foley consisting of a
22 cover sheet and 38 pages of questions and answers?

23 A Yes.

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

1 A No.

2 Q Is that then the rebuttal testimony that you are adopting
3 today?

4 A Yes.

5 Q O.K. Are you sponsoring any exhibits as part of your
6 rebuttal testimony in this case?

7 A Yes.

8 Q Is that rebuttal exhibit designated as Exhibit A-22?

9 A Yes.

10 Q Do you have any changes to make to that rebuttal exhibit?

11 A No.

12 MS. HAYDEN: Your Honor, DTE Electric
13 moves to bind into the record the Qualifications and
14 Revised Direct Testimony and the Rebuttal Testimony of
15 Neal T. Foley, and for the admission at the end of cross
16 of Exhibits A-16, A-18, and A-22, and tenders Mr. Foley
17 for cross-examination.

18 JUDGE STALEY: Thank you. Is there any
19 objection to the binding in of the prefiled Direct and
20 Rebuttal Testimony of Neal T. Foley on behalf of DTE
21 Electric Company?

22 Hearing none, the prefiled -- my
23 apologies, I want to be clear. The prefiled Revised
24 Testimony as well as prefiled Rebuttal Testimony of
25 Mr. Neal T. Foley are bound into the record.

(Revised Direct Testimony and Rebuttal Testimony
bound in.)

- - -

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of)
DTE ELECTRIC COMPANY)
for Approval of Special Contracts)
and for other relief)

Case No. U-22058

QUALIFICATIONS
AND
REVISED DIRECT TESTIMONY
OF
NEAL T. FOLEY
(PUBLIC)

DTE ELECTRIC COMPANY
QUALIFICATIONS AND REVISED DIRECT TESTIMONY OF NEAL T. FOLEY

Line
No.

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

2 A1. My name is Neal Foley. My business address is: One Energy Plaza, Detroit,
3 Michigan 48226. I am employed by DTE Electric Company (“DTE Electric” or
4 “Company”).

5

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

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

8

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

10 A3. I received a Bachelor of Science in Aerospace Engineering and a Bachelor of
11 Science in Mechanical Engineering from the University of Michigan. I also
12 received a Master of Science in Systems Engineering from Johns Hopkins
13 University and a Master of Business Administration from Georgetown University.

14

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

16 A4. In 2007, I was employed by Lockheed Martin Corporation as a Satellite Operations
17 Engineer. In 2008, I was hired by Booz Allen Hamilton as an Associate Consultant
18 in its Federal consulting practice. In 2012, I was hired by Deloitte as a Manager of
19 Financial Analysis in its Federal consulting practice. In 2014, I was hired by
20 McKinsey & Company as an Associate Consultant, ultimately being promoted to
21 Engagement Manager before my departure in 2017. In 2017, I was hired by DTE
22 Energy Company as Manager of Corporate Strategy. In this role, I was broadly
23 responsible for tracking and assessing utility industry trends, executing analyses to
24 better understand the economic impacts of emerging technologies and business
25 models, and leading strategic initiatives for the Company. In December 2020, I was

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1 promoted to Director of Regulatory Affairs where I was responsible for the
2 management of regulatory activities related to DTE Electric's Load Research,
3 Tariffs, Pricing, and Rate Design. In December 2024, I started my current role as
4 Director of Electric Marketing for DTE Electric.

5

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

8 A5. Yes. I have sponsored testimony and exhibits before the MPSC in the following
9 DTE Electric cases:

10	<u>Case No.</u>	<u>Description</u>
11	U-20836	DTE 2022 Electric Rate Case
12	U-21376	DTE 2023 Distributed Generation Tariff Options
13	U-21297	DTE 2023 Electric Rate Case
14	U-21534	DTE 2024 Electric Rate Case
15	U-21860	DTE 2025 Electric Rate Case
16	U-21990	DTE 2025 Data Center Special Contracts

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1 **Purpose of Testimony**

2 **Q6. What Commission action is the Company seeking through the instant case?**

3 A6. The Company is seeking the Commission's approval of two special contracts and
4 other related relief that will govern how the Company serves a new, large load
5 customer. Specifically, the Company is seeking approval of the following special
6 contracts that have been executed between the Company and Google LLC ("the
7 Customer").

- 8 • Primary Supply Agreement ("PSA")
- 9 • Clean Capacity Accelerator Agreement ("CCAA")

10 Taken together, the PSA and CCAA are referred to as the "the Contracts"
11 throughout my testimony.

12

13 The Company is requesting Commission review of the Contracts by September 10,
14 2026.

15

16 **Q7. Why is the Company requesting a Commission order by September 10, 2026?**

17 A7. The September 10th date will satisfy the conditions precedent set forth in the
18 Contracts which require Commission approval by September 10, 2026.

19

20 **Q8. Can you summarize the Contracts that are being proposed for approval?**

21 A8. Yes. The PSA stipulates that the Customer will receive electric service under the
22 Company's Rate Schedule D11 ("D11") which is the Company's Primary Supply
23 Rate. The PSA also establishes additional protections for the Company's other
24 customers that are not included in Rate Schedule D11. Importantly, the PSA
25 ensures that the aggregate benefits of the Contracts, including revenues received

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1 from the Customer and avoided costs realized through the Contracts, outweigh the
2 costs of serving the Customer's load. If aggregate benefits do not outweigh the
3 costs, the Customer will pay the difference.

4
5 The CCAA allows the Company to deploy a portfolio of up to 480 MW of energy
6 storage projects and up to 1,600 MW of renewable energy projects, and recover
7 from the Customer the full cost of these projects. Therefore, the costs of the energy
8 storage and renewable energy projects developed to fulfill the CCAA with the
9 Customer will not be passed on to the Company's other customers. In addition, the
10 CCAA allows the Company to receive from the Customer 300 MW of
11 Midcontinent Independent System Operator ("MISO") Zone 7 Zonal Resource
12 Credits ("ZRCs") at no cost.

13
14 The Customer will receive capacity and renewable generation credits for the
15 projects that are deployed and the ZRCs that are received as part of the CCAA.
16 Importantly, the credits received by the Customer for a given project or transferred
17 ZRC cannot be greater than the incremental market revenues that are generated by
18 that project or ZRC for a given billing period. This ensures that the Company's
19 other customers do not bear any costs of CCAA resources.

20
21 Table 1 below summarizes these terms and compares them to the Company's
22 standard D11 rate.

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1

Table 1 Comparison of PSA/CCAA contract terms to D11 rate

2

Term	PSA/CCAA	Standard D11
Contract duration	20-years	5-years
Pricing and ability to change rates	D11 pricing; 24-month and other restrictions on rate switching	D11 pricing; 12-month restriction on rate changes
Minimum Billing Demand (MBD)	80%	50-65% (demand ratchets)
Load Ramp Flexibility	Customer can temporarily delay load ramp by up to 18-months	Not addressed
Contract Capacity Reductions	Customer cannot reduce contract capacity	Not addressed beyond initial term and ratchets
Termination Payment	Customer ensures 15-years of MBD payments	Not addressed
Affordability backstop	Customer ensures aggregate benefits of the Contracts are greater than aggregate costs	Not addressed
Energy Waste Reduction	Customer commits to self-directed EWR plan	Not addressed
Credit and collateral requirements	Credit and collateral requirements	No specific requirement
Direct payment of energy storage	Up to 480 MW, including up to 55 MW of long-duration storage	Not addressed
Direct payment of renewable energy	Up to 1,600 MW	Not addressed

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1 **Q9. Are there any other agreements between the Company and the Customer to**
2 **support providing electric service?**

3 A9. Yes, there are two additional agreements that support the Company providing
4 electric service to the Customer:

- 5 • Rider 12 Demand Response ("DR") Agreement which commits the
6 Customer when called to reduce its electrical demand at its facility to 650
7 MW between June 2027 through May 2033¹; in his testimony, Witness
8 Burgdorf describes the Rider 12 DR Agreement
- 9 • Line Extension Agreement ("LEA") which commits the Customer to pay
10 for up to \$50 million of distribution upgrades to serve their facility; in his
11 testimony, Witness Benyard describes how the Company expects total
12 distribution upgrades to cost less than \$50 million

13

14 The Rider 12 DR Agreement and LEA are standard contracts that the Company is
15 not seeking Commission approval of in the instant case. They are being discussed
16 as part of the Company's filing to provide a complete description of how the
17 Company intends to serve the Customer.

18

19 **Q10. What is the purpose of your testimony?**

20 A10. The purpose of my testimony is to first introduce the Company's witnesses and
21 describe the scope of their testimonies. I then generally describe and support the
22 structure and provisions of the Contracts and how the Contracts mitigate the risk of
23 stranded assets.

¹ During load ramp period, Customer is required to reduce load to 65% of applicable contract capacity at the time of the event which could be less than 650 MW

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

2 A11. My testimony includes the following sections:

- 3 1. Introduction of Company witnesses
- 4 2. Overview of the Customer
- 5 3. Proposed PSA
- 6 4. Proposed CCAA
- 7 5. Regulatory treatment
- 8 6. Summary of requested Commission action

9

10 **Q12. Are you sponsoring any exhibits in this proceeding?**

11 A12. Yes. I am sponsoring the following exhibits:

12	<u>Exhibit</u>	<u>Description</u>
13	A-16	Primary Supply Agreement - Confidential
14	A-18	Clean Capacity Accelerator Agreement - Confidential

15

16 **Q13. What was your involvement in the preparation of the Contracts?**

17 A13. I was involved in the development of the key terms included in the Contracts, as
18 discussed throughout my testimony.

19

20 **Introduction of Company Witnesses**

21 **Q14. How will the Company present evidence in support of its proposals in this**
22 **case?**

23 A14. The Company will present its case through six witnesses, including myself, as
24 described below.

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- 1) Mr. Kevin L. Bilyeu discusses the impact that the Customer's load will have on the Company's Renewable Portfolio Standard ("RPS") obligations, describes the Company's Voluntary Green Pricing ("VGP") program as it relates to special contracts, and how the deployment of renewable energy under the CCAA will help offset those impacts.
- 2) Mr. Steven N. Benyard discusses the projects that are required to provide safe and reliable service to the Customer; in addition, he discusses the cost estimate for the distribution and transmission upgrades needed to support the Customer's connection to the electric grid.
- 3) Mr. Shawn D. Burgdorf discusses changes in the capacity resource mix and the Power Supply Cost impacts from the addition of the Customer's load. He also describes the Company's Rider 12 demand response contract with the Customer.
- 4) Mr. Justin J. W. Brooks explains the results of the resource adequacy analysis performed at the Company's request in years 2029 and 2033 to support the addition of the Customer's load to the DTE Electric system.
- 5) Mr. Aaron Willis discusses the Company's customer impact modeling which demonstrates how the Company expects its other customers to realize a benefit of approximately \$1.7 billion during the term of the Contracts.

Overview of the Customer

Q15. Can you describe the Customer?

A15. Yes. The Customer (Google LLC) is a subsidiary of Alphabet Inc., a well-known technology company that is the third largest company in the United States by

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1 market capitalization. The Customer intends to build a data center that will be
2 engaged in the management, storage, processing, and distribution of data.

3

4 **Q16. Where will the data center be located?**

5 A16. The data center will be located in Van Buren Township, Michigan, within the
6 Company's service territory. It will be developed on roughly 280 acres.

7

8 **Q17. What is the planned Customer load at the facility and when will the load
9 materialize?**

10 A17. The maximum load at the facility is 1,000 MW ("max load" or "contract capacity").
11 The Customer's load is planned to begin materializing in December 2027², with
12 max load being achieved by December 2028 ("load ramp" or "load ramp period")
13 and held constant thereafter. Later in my testimony, I describe the Customer's
14 ability to adjust the timing of the load ramp and the date by which they achieve
15 their max load ("Load Ramp Completion Date").

16

17 **Q18. Will the Company's other customers benefit from the Contracts?**

18 A18. Yes. In his testimony Witness Willis describes how the Contracts are expected to
19 deliver a \$1.7 billion benefit to the Company's other customers.

20

21 **Q19. Will serving the Customer's load have an impact on the Company's Energy
22 Waste Reductions ("EWR") targets?**

23 A19. Yes. Later in my testimony I describe the Customer's commitment to achieving
24 EWR targets contained within the PSA.

² Load to support construction of the site could materialize before December 2027.

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1 **Primary Supply Agreement - Overview**

2 **Q20. Can you provide an overview of the PSA?**

3 A20. Yes. The PSA, Exhibit A-16, governs the obligations of the Company and the
4 Customer as it relates to the electric service that the Customer will receive.

5

6 At a high level, the PSA requires that the Customer take service on D11, including
7 all associated surcharges, and includes additional terms that are not currently
8 included in Rate Schedule D11. Of critical importance, the PSA ensures that the
9 aggregate benefits of the Contracts, including revenues received from the Customer
10 and avoided costs realized through the Contracts, outweigh the costs of serving the
11 Customer's load.

12

13 **Q21. What are the terms of the PSA between the Company and the Customer that**
14 **differ between a standard contract under the Company's D11 rate?**

15 A21. The terms of the PSA that differ from the D11 rate are the following:

- 16 • Contract duration
- 17 • Pricing and ability to change rates
- 18 • Minimum Billing Demand (MBD)
- 19 • Customer load ramp flexibility
- 20 • Contract capacity reductions
- 21 • Termination payment
- 22 • Affordability backstop
- 23 • Energy Waste Reduction
- 24 • Credit and collateral requirements

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1 I will describe each of these elements in the following sections of my testimony.

2

3 **Primary Supply Agreement – Contract Duration**

4 **Q22. What is the contract duration of the PSA?**

5 A22. The PSA contract duration is 20 years, beginning at the time the Customer first
6 receives electric service at its facility. As the Customer is expected to begin taking
7 service in December 2027, the Company expects the PSA contract duration to
8 extend through November 2047.

9

10 Later in my testimony I describe the Customer's ability to temporarily delay their
11 load ramp, including when they begin receiving electric service at the data center
12 facility.

13

14 The PSA will automatically renew for up to two additional 5-year terms. The
15 Customer can opt-out of these automatic renewals by providing notice to the
16 Company at least 36-months prior to the beginning of a renewal period.

17

18 **Q23. Is the PSA contract duration beneficial to the Company's other customers?**

19 A23. Yes. The PSA contract duration is much longer than the Company typically requires
20 for large industrial customers. For comparison, the standard agreement for a new
21 customer under D11 over 1 MW of peak demand is five years.

22

23 A 20-year PSA contract duration represents a significant commitment on behalf of
24 the Customer to the Company and its other customers. It ensures that the Customer

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1 will make their proportionate contribution to the Company's system costs for a
2 longer period than the Company normally requires of its customers under D11.

3

4 **Primary Supply Agreement – Pricing and Ability to Change Rates**

5 **Q24. How is electric service pricing structured under the PSA?**

6 A24. Under the PSA, the Customer agrees to take service on D11 and pay all applicable
7 surcharges (e.g., the Power Supply Cost Recovery ("PSCR") Surcharge).

8

9 **Q25. Can the Customer change rate schedules under the PSA?**

10 A25. Under the PSA, the Customer can only change rate schedules under the following
11 conditions:

- 12 • The Customer must request a rate schedule change 24 months in advance of
- 13 the rate schedule change taking effect;
- 14 • The Customer cannot request a rate schedule change that would take effect
- 15 prior to 24 months after their Load Ramp Completion Date;
- 16 • The Customer can only change to a rate schedule that is approved by the
- 17 Commission after the PSA became effective; and
- 18 • The Customer can only change to a rate schedule that is not cross-subsidized
- 19 by any other customer group.

20

21 **Q26. Are the PSA pricing and ability to change rate schedule terms reasonable?**

22 A26. Yes. D11 is a cost-based rate that will ensure that the Customer makes their
23 proportionate contribution to the Company's fixed system costs. Being subject to
24 the PSCR surcharge ensures that the Customer makes their proportionate
25 contribution both to the incremental fuel and purchased power costs that they are

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1 introducing, and to the fixed costs of renewable energy assets and transmission
2 costs that are recovered through that mechanism.

3
4 The limitations on rate schedule switching in the PSA are also reasonable. The
5 notice period ensures that any rate schedule change can be appropriately
6 incorporated through a subsequent rate case. The limitation that the rate schedule
7 be newly approved and not cross-subsidized provides appropriate protections
8 around the types of future rates that the Customer may be eligible for to ensure any
9 potential future rate change would not negatively impact other customers.

10

11 **Primary Supply Agreement – Minimum Billing Demand**

12 **Q27. How is Minimum Billing Demand (“MBD”) structured under the PSA?**

13 A27. Under the PSA, the Customer agrees that the minimum demand for a given billing
14 period will be 80% of the contract capacity applicable for that billing period. In
15 practice, this means the Customer’s Minimum Monthly Charge (“MMC”) for a
16 given billing period will be calculated using an 80% MBD as applied to the
17 customer’s contracted capacity during the specific billing period. The MBD will
18 increase during the Customer’s load ramp and then will be held constant at the
19 contract capacity once the max load is achieved.

20

21 Given that the Customer’s max load is 1,000 MW, the MBD will be 800 MW (i.e.,
22 80% of 1,000 MW) once the Load Ramp Completion Date is reached.

23

24 **Q28. How will the MBD be applied?**

25 A28. On D11, the Customer is subject to three demand charges:

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- 1 • Power Supply Capacity Demand Charge
- 2 • Power Supply Non-Capacity Demand Charge
- 3 • Distribution Demand Charge

4

5 The first two demand charges (Power Supply Capacity and Power Supply Non-
6 Capacity) are typically calculated based on the billing period's monthly on-peak
7 billing demand as defined in D11. Under D11 these charges would also typically
8 be subject to a 65% ratchet³; however, this term is superseded by the 80% MBD
9 agreed to in the PSA.

10

11 The third demand charge (Distribution) is typically calculated based on the
12 maximum demand measured during the previous 12 months as defined in Rate
13 Schedule D11. Under D11 this charge would also typically be subject to the greater
14 of actual maximum demand or 50% of contract capacity; however, this term is
15 superseded by the 80% MBD agreed to in the PSA.

16

17 Under the PSA, the Company will calculate all three demand charges using the
18 greater of:

- 19 • 80% of the contract capacity applicable for the billing period; or
- 20 • The customer's actual billing demand if greater than 80% of the contract
- 21 capacity applicable for the billing period.

³ The D11 ratchet mechanism is defined as "[t]he monthly on-peak billing demand will not be less than 65% of the highest monthly on-peak metered billing demand during the billing months of June, July, August, September, and October of the preceding eleven billing months, nor less than 50 kilowatts."

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1 Based on the D11 rates approved in Case No. U-21860, the Customer's MMC will
2 be \$13.8 million per month, or \$165.1 million per year⁴.

3

4 **Q29. Is the MMC impacted if the Customer's load does not fully materialize?**

5 A29. No. Even if the customer's actual usage never reaches the contract capacity (i.e.,
6 1,000 MW) agreed to in the PSA, the MMC will be calculated based on that contract
7 capacity. While the timing of the Customer's load ramp can be temporarily delayed,
8 the Customer cannot reduce their contract capacity during the term of the PSA once
9 the load ramp is reached.

10

11 **Q30. Does the MBD provide adequate protection for the Company's other**
12 **customers?**

13 A30. Yes. The MBD term ensures that the Company will collect from the Customer a
14 minimum amount of revenue regardless of the Customer's actual demand. Through
15 the PSA the Company is committing to make available the max load to the
16 Customer for the life of the contract. The MBD likewise commits the Customer to
17 pay for that capacity through D11 demand charges. As described above, the MBD
18 provision in the PSA is higher than the standard term included in the Company's
19 D11 rate.

20

21 **Primary Supply Agreement – Customer load ramp flexibility**

22 **Q31. Can the Customer adjust the timing of when their load will materialize or**
23 **when they must achieve max load?**

⁴ See WP NTF-1 for calculation

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1 A31. Yes. The Customer can temporarily delay their load ramp or any increase in the
2 scheduled ramp by up to 18 months in the aggregate. The Customer cannot modify
3 the contract capacity that the Company has committed to serve. In practice, this
4 means that the Load Ramp Completion Date could occur as late as June 2030 if the
5 Customer elects to delay by the maximum 18 months allowed in the PSA.

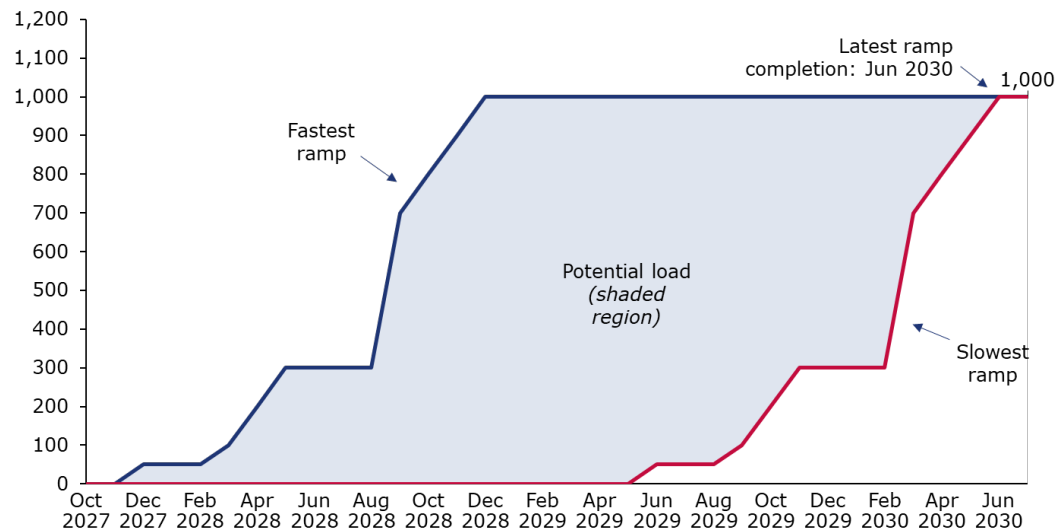
6

7 Figure 1 demonstrates the Customer's slowest and fastest ramps allowable under
8 the PSA.

9

10

Figure 1 Customer Load Ramp Flexibility (MW)



11

12 **Primary Supply Agreement – Contract Capacity Reductions**

13 **Q32. Can the Customer's contract capacity be reduced during the term of the PSA?**

14 A32. Yes. In summary, the PSA addresses a situation where the Company cannot meet
15 the Customer's load ramp or max load due to any of the following conditions:

16

- The CCAA or Rider 12 DR Agreement is terminated;

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- 1 • The Company is unable to achieve or maintain the Customer's load ramp
- 2 or max load due to reasons not attributable to the Company;
- 3 • The Company is unable to achieve or maintain the Customer's load ramp
- 4 or max load due to the Customer's underperformance or nonperformance
- 5 under any agreement with the Company; and/or
- 6 • The Company determines that the energy storage portfolio being deployed
- 7 under the CCAA is not feasible.

8

9 If any of the above conditions are true, the Company and the Customer will meet
 10 to negotiate a solution that could include, for example, an adjustment to the
 11 resources being deployed under the CCAA, an adjustment to the Customer's load
 12 ramp or max load, and/or a pass-through mechanism whereby the cost of
 13 incremental MISO market purchases needed to meet the Customer's load ramp or
 14 max load are passed directly to the Customer.

15

16 If the Company and the Customer cannot agree on a solution, the Company can
 17 unilaterally propose an adjustment to the Customer's load ramp or max load. The
 18 Customer can accept the proposed adjustment or terminate the agreement and pay
 19 all applicable termination payments.

20

21 **Q33. Does the ability of the Company to reduce the Customer's load ramp or max**
 22 **load adequately protect the Company's other customers?**

23 A33. Yes. The ability of the Company to reduce the Customer's contract capacity under
 24 certain conditions provides protection for the Company's generation and
 25 distribution systems and for the reliability of its other customers. This mitigates any

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1 risk that the Company's other customers would be impacted if the Company does
2 not have sufficient resources to serve the Customer's load.

3

4 **Primary Supply Agreement – Termination Payment**

5 **Q34. Can you explain the termination payment under the PSA?**

6 A34. Yes. The termination payment was designed such that the Company will recover at
7 least 15 years of Minimum Monthly Charges once the Customer achieves their max
8 load. If the PSA is terminated before the fifteenth anniversary of the Load Ramp
9 Completion Date, the Customer will be subject to a termination payment based on
10 the MMC multiplied by the greater of 1) the number of months from the early
11 termination date to the fifteenth anniversary of the Load Ramp Completion Date,
12 or 2) 24 months. If the PSA is terminated after the fifteenth anniversary of the Load
13 Ramp Completion Date, the customer is subject to a termination payment equal to
14 24 months of Minimum Monthly Charges.

15

16 Under this mechanism and based on the D11 rate approved in Case No. U-21860,
17 the termination payment at the Load Ramp Completion Date is \$2.48 billion⁵.

18

19 The Company notes that this termination payment is only associated with the PSA.
20 The CCAA has separate, incremental termination payment that I discuss later in my
21 testimony.

22

23 **Q35. Does the termination payment benefit the Company's other customers?**

⁵ See WP NTF-2 for calculation of the termination payment.

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1 A35. Yes. The termination payment represents a long-term commitment by the Customer
2 of at least 15 years to contribute to the Company's overall system costs, thereby
3 reducing the cost responsibility of the Company's other customers.
4

5 **Primary Supply Agreement – Energy Waste Reduction**

6 **Q36. What commitment is the Customer making in the PSA to support the State of**
7 **Michigan's EWR objectives?**

8 A36. In the PSA, the Customer is committing to participate and comply with the self-
9 directed EWR plan requirements as set forth in MCL 460.1093. In accordance with
10 the Commission Order in Case No. U-21627, the Customer's expected annual peak
11 load will qualify them to self-direct an EWR plan. The savings identified in the
12 Customer's self-directed EWR plan will be counted toward the Company's
13 statutory goals and thus support the State of Michigan's EWR objectives
14

15 **Primary Supply Agreement – Affordability Backstop**

16 **Q37. Does the PSA ensure that the rates paid by the Company's other customers**
17 **will not be negatively impacted by the contracts?**

18 A37. Yes. The PSA ensures that the aggregate benefits, including revenues received from
19 the Customer and avoided costs realized through the Contracts, outweigh the costs
20 of serving the Customer's load.
21

22 Specifically, the PSA (Exhibit A-16) states:
23

24 "The Parties acknowledge that a goal of this Agreement and the Related
25 Agreements is to protect other customers, other customer classes and Company

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1 from funding the costs to serve Customer. The Parties also acknowledge that
2 the combined revenues received by the Company under this Agreement and the
3 applicable Related Agreements along with any avoided costs attributable to
4 Google should be considered in regulatory proceedings applicable to
5 Company's cost to serve Customer, and the Parties shall act in good faith to
6 ensure such combined revenues and avoided costs are presented in such
7 proceedings to the extent applicable. If, at any time during the Term, the
8 Commission (a) issues a ruling or order determining that the costs to serve
9 Customer exceed the combined revenues paid or payable to the Company under
10 this Agreement and the applicable Related Agreements, or (b) disallows
11 Company's recovery of costs to the extent attributable to serving Customer,
12 then, in either case, Customer agrees to comply with any such ruling or order
13 to ensure that Customer pays all costs associated with its service from
14 Company, and, as applicable, Customer shall reimburse Company for any
15 unrecovered costs, plus interest accrued on such amount at the Interest Rate
16 within ninety (90) days of any such order; provided, however, that
17 notwithstanding the foregoing, Customer shall not be required to reimburse
18 Company for unrecovered costs incurred due to the gross negligence or willful
19 misconduct of Company." (Section 5.1.3)

20

21 In summary, the Customer agrees to comply with any Commission order ensuring
22 that they are fully covering their costs. In addition, the Customer agrees to
23 reimburse the Company for any unrecovered costs caused by a Commission
24 disallowance attributable to the Customer's load.

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1 **Q38. Why has the Company agreed to “act in good faith to ensure such combined**
2 **revenues and avoided costs are presented in such proceedings to the extent**
3 **applicable”?**

4 A38. The Company believes it is critically important that the Commission take an
5 aggregate view of the benefits and costs of serving the Customer’s load over the
6 life of the contract. The individual aspects of the agreements will be addressed in
7 different regulatory proceedings. For example, the benefit to base rates of serving
8 the Customer’s load will be addressed in rate cases, while the costs of incremental
9 transmission investments will be addressed in PSCR plan and reconciliation cases.
10 Long term generation needs will be addressed through IRP cases, while approval
11 of renewable generation plans will be requested through REP cases.

12

13 Taking a narrow view of benefits and costs, for example by only considering the
14 costs and benefits of the specific items being directly addressed in each case, may
15 result in decisions that are not well-aligned with the broader provision of service to
16 large-load customers such as the Customer.

17

18 As such, the Company agreed to present an aggregate view of serving the Customer
19 as applicable in future regulatory proceedings.

20

21 **Primary Supply Agreement – Credit and Collateral Requirements**

22 **Q39. Does the PSA include credit and collateral requirements?**

23 A39. Yes. The PSA includes credit and collateral requirements through a Parent
24 Guaranty (“PG”) and as necessary based on the parent’s credit rating, a letter of

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1 credit designed to protect the Company and its customers in the event of Customer
2 default.

3

4 Specifically, once the PSA is approved the Customer will initially provide a PG to
5 cover a portion of the Customer's financial obligations under the PSA. Later in the
6 contract term, the PG is reduced once the forecasted termination payment of the
7 PSA drops below the initial PG and a larger PG becomes superfluous. If at any
8 point the Customer's parent's credit rating drops below a pre-defined threshold,
9 then the Customer will be required to post a Letter of Credit ("LoC") equal the PG
10 amount applicable at that time.

11

12 **Q40. Is the PSA credit and collateral structure consistent with prior Commission**
13 **guidance?**

14 A40. Yes. The proposed structure is consistent with:

15 • The Commission's December 18, 2025, Order in Case No. U-21990 in
16 which it provided conditional approval of a PSA related to the provision of
17 service to a different large load customer. In that PSA, the large load
18 customer is required to post a PG and, as necessary based on its parent's
19 credit rating, a LoC based on its financial obligations under the PSA. This
20 is the same structure that is being proposed for the PSA in this instant case.

21

22 • The Commission's November 6, 2025, Order in Case No. U-21859 in which
23 it approved amendments to Consumers Energy's General Primary Demand
24 Rate ("Rate GPD") applicable to large load customers. In that order, the
25 Commission established a minimum termination payment starting at 15-

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1 years MMC (equal to the minimum length of a contract) backed by a 50%
2 LoC or cash. This effectively establishes a minimum collateral requirement
3 of 7.5-years of MMC, which the PSA in the instant case satisfies.

4
5 Notably, the Commission also stated that it “remains open to considering
6 the use of parent guarantees—either on their own or in concert with other
7 collateral—on a case-by-case basis” (page 112). In the instant case, given
8 the creditworthiness of the Customer’s parent, the Company is proposing
9 the use of a PG.

10

11 **Clean Capacity Accelerator Agreement (CCAA) - Overview**

12 **Q41. Can you provide an overview of the CCAA between the Company and the**
13 **Customer?**

14 A41. Yes. The CCAA, Exhibit A-18, governs the obligations of the Company and the
15 Customer related to the deployment and cost recovery of up to 480 MW of energy
16 storage projects and up to 1,600 MW of renewable energy projects. The Customer
17 will pay the full cost (i.e., revenue requirement) of the projects over each project’s
18 depreciable life.

19

20 In addition, the CCAA commits the Customer to transfer 300 MW of ZRCs to the
21 Company which the Company can then utilize to meet its capacity needs. The ZRCs
22 will be provided by the Customer from June 1, 2028 to May 31, 2033.

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1 The Customer will receive capacity and/or renewable generation credits for the
2 energy storage projects, renewable energy projects, and ZRCs that are paid for or
3 provided by the Customer under the CCAA.

4

5 **Q42. What are the key terms of the CCAA between the Company and the**
6 **Customer?**

7 A42. The key terms of the CCAA are the following:

- 8 • Contract duration
- 9 • Energy storage portfolio
- 10 • Renewable energy portfolio
- 11 • Project pricing
- 12 • ZRC transfer
- 13 • Capacity credits
- 14 • Renewable generation credits
- 15 • Termination and termination payment
- 16 • Credit and collateral requirements

17

18 **Clean Capacity Accelerator Agreement – Contract Duration**

19 **Q43. What is the contract duration of the CCAA?**

20 A43. The CCAA contract duration is set such that the CCAA ends at the same time as
21 the initial term of the PSA. Like the PSA, the CCAA ends 20 years after the
22 Customer first receives electric service at the data center facility.

23

24 **Q44. Does the CCAA contract length offer adequate protection against stranded**
25 **asset risk to the Company's other customers?**

Line
No.

1 A44. Yes. As I describe later in my testimony, the full cost of projects deployed under
2 the CCAA will be recovered during the CCAA contract term. The CCAA is
3 designed such that any risk of stranded asset risk associated with CCAA projects is
4 mitigated.

5

6 **Clean Capacity Accelerator Agreement – Energy Storage Portfolio**

7 **Q45. What obligations does the Company have related to the deployment of energy**
8 **storage projects under the CCAA?**

9 A45. Under the CCAA, the Company can deploy a portfolio of energy storage projects
10 of up to 480 MW through a combination of self-build projects, Build Transfer
11 Agreements (“BTAs”), and third-party Tolling Agreements (“TAs”).

12

13 Included within the 480 MW of energy storage is up to 425 MW of 4-hour lithium-
14 ion energy storage, and up to 55 MW of long duration storage (i.e., at least 8-hour
15 duration). The long duration storage can be lithium-ion or a different technology.

16

17 **Q46. How will energy storage projects be selected for development under the**
18 **CCAA?**

19 A46. The Company intends to issue an Energy Storage Request for Proposal (“RFP”) to
20 identify energy storage projects to be deployed under the CCAA. The RFP will be
21 conducted under a competitive procurement process that follows the MPSC’s
22 Competitive Procurement Guidelines for Rate-Regulated Electric Utilities and the
23 terms of the Company’s 2022 Integrated Resource Plan (“IRP”) Settlement
24 Agreement dated July 26, 2023 (“IRP Settlement Agreement”) in Case No. U-
25 21193.

Line
No.

1 **Q47. Will the energy storage projects deployed under the CCAA be Company**
2 **owned, third party owned, or a combination of both?**

3 A47. The energy storage projects deployed under the CCAA will be a combination of
4 Company owned and third party owned. The IRP Settlement Agreement stipulated
5 that additional energy storage projects should be allocated consistent with the
6 allocation for the PCA build between Company owned and third party owned
7 projects⁶. The Company intends to select projects that are consistent with this
8 ownership split identified in the IRP Settlement Agreement.

9

10 **Q48. Will the Company submit energy storage projects deployed under the CCAA**
11 **to the Commission for review and approval?**

12 A48. Yes. The Company will submit each project to the Commission for review and
13 approval prior to construction.

14

15 **Clean Capacity Accelerator Agreement – Renewable Energy Portfolio**

16 **Q49. What obligations does the Company have related to the deployment of**
17 **renewable energy projects under the CCAA?**

18 A49. Under the CCAA, the Company can deploy a portfolio of renewable energy projects
19 up to 1,600 MW.

20

21 **Q50. How will the deployment of renewable energy under the CCAA be treated with**
22 **respect to the Company’s Renewable Portfolio Standard (“RPS”) obligations?**

23 A50. As Witness Bilyeu describes in his testimony, the CCAA terms governing the
24 deployment of renewable energy comply with the Section 61 Settlement Agreement

⁶ Section 13 of IRP Settlement (<https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y000008puPjAAI>)

Line
No.

1 discussed in his testimony. Therefore, the renewable energy resources included in
2 the CCAA are considered part of a customer-requested VGP special contract and
3 treated as such for RPS purposes.

4

5 **Q51. How will renewable energy projects be selected for development under the**
6 **CCAA?**

7 A51. Renewable energy projects will be selected consistent with the Section 61
8 Settlement Agreement, with the details of the competitive process being agreed
9 upon with the Customer. See Witness Bilyeu's testimony for additional details.

10

11 **Q52. Will the Company submit renewable energy projects deployed under the**
12 **CCAA to the Commission for review and approval?**

13 A52. Yes. As described by Witness Bilyeu, the Company will submit each project to the
14 Commission for review and approval prior to construction.

15

16 **Clean Capacity Accelerator Agreement – Project Pricing**

17 **Q53. What is the Customer pricing structure for energy storage and renewable**
18 **energy projects deployed under the CCAA?**

19 A53. For both energy storage and renewable energy projects, the Customer will pay the
20 full cost of each project during its respective depreciable life⁷. For each Company
21 owned project in the portfolio, the Company will calculate an annual revenue
22 requirement for the depreciable life of the project in the same manner that a revenue
23 requirement is calculated in a general rate case for energy storage projects or a

⁷ Currently approved depreciable life is 15-years for energy storage, 23-years for solar energy assets, and 27-years for wind energy assets

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1 Renewable Energy Plan (“REP”) for renewable energy projects. The revenue
2 requirement will include, for example:

- 3 • Allowance for Funds Used During Construction (“AFUDC”) accumulated
- 4 during the construction of the project
- 5 • Depreciation
- 6 • The Company’s prevailing authorized rate of return
- 7 • Amortization of Investment Tax Credits (“ITC”) generated by the
- 8 construction of the site
- 9 • O&M
- 10 • Property Tax
- 11 • Insurance

12

13 For third party TAs or Power Purchase Agreements (“PPA”), the revenue
14 requirement will be equal to the annual cost of the TA or PPA plus any authorized
15 financial incentive under MCL 460.1028.

16

17 For billing purposes, the annual project revenue requirement of each project will be
18 evenly divided into the number of billing periods applicable to that year to
19 determine the billing period project charge⁸. The summation of individual project
20 billing period charges will be invoiced to the customer.

21

22 **Q54. When will the revenue requirement be determined for an individual energy**
23 **storage or renewable energy project for the purposes of billing the Customer?**

⁸ In general, the applicable billing periods during a year will be 12, although could vary in the first and final calendar years of the depreciable life since project CODs could happen mid-year.

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1 A54. For the purposes of billing the Customer, the revenue requirement for Company
2 owned projects will first be calculated around the time the project achieves its
3 Commercial Operation Date (“COD”). At that time the Company will provide the
4 Customer with a projection of the annual revenue requirement for the project for
5 each year of the project’s depreciable life. This projection will be based on actual
6 construction costs and a forecast of ongoing lifetime costs.

7

8 For third party TAs or PPAs, the cost will first be calculated when the Company
9 enters into the TA or PPA.

10

11 **Q55. Is the Customer still responsible for the costs of a project if its depreciable life**
12 **extends beyond the term of the CCAA?**

13 A55. Yes. Given that the current depreciable life of solar and wind assets is 23 and 27-
14 years respectively it is expected that a portion of each renewable energy project’s
15 depreciable life will extend beyond the term of the CCAA. In addition, it is possible
16 that a portion of an energy storage project’s depreciable life could extend beyond
17 the term of the CCAA depending on its COD. To ensure that the Customer fully
18 pays for each project over its depreciable life, the CCAA allows the Company to
19 accelerate recovery of a project’s costs.

20

21 More specifically, the Company will calculate the costs (i.e., revenue requirement)
22 during each project’s depreciable life that will be incurred beyond the term of the
23 CCAA. These costs will be collected from the Customer during the term of the
24 CCAA by evenly dividing these costs by the number of billing periods that will
25 occur during the term of the CCAA for such a project. The result will be added to

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1 the Customer's invoice for each billing period of the CCAA applicable to the
2 project. In this way, the Customer will fully pay for each project even if the
3 project's depreciable life extends beyond the term of the CCAA.

4
5 In practice, this means that the Customer will be paying more than the revenue
6 requirement for a project during the term of the CCAA. The Company is proposing
7 to record this excess recovery (i.e., customer charge less revenue requirement of
8 the project) as a Regulatory Liability. This liability will grow throughout the term
9 of the CCAA and can then be used beyond the term of the CCAA to offset the
10 remaining costs (i.e., revenue requirement) of the projects. This approach ensures
11 that the Company's other customers will not be responsible for the costs of the
12 renewable projects during their depreciable lives.

13

14 **Q56. Is the revenue requirement for an energy storage or renewable energy project**
15 **fixed once it is initially calculated?**

16 A56. No. After each calendar year, the Company will perform a cost reconciliation for
17 each project deployed under the CCAA. That reconciliation will compare the
18 amount charged to the Customer during the previous calendar year for a given
19 project to the actual costs of that project. Any over recovery or under recovery will
20 be incorporated into the subsequent year's Customer charges.

21

22 Under this approach, the Customer pays the actual costs of each project deployed
23 under the CCAA.

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1 **Q57. Will the Commission and other stakeholders have an opportunity to review**
2 **the reconciliation?**

3 A57. The reconciliation process is between the Customer and the Company. However,
4 the costs of energy storage projects and the associated Customer charges will be
5 provided in the Company's future general rate cases. The costs of renewable energy
6 projects and the associated Customer charges will be provided in the Company's
7 future annual REP reconciliation cases. At those times, the Commission and other
8 stakeholders will have the opportunity to review the costs and Customer revenues
9 associated with the energy storage and renewable energy projects deployed under
10 the CCAA.

11

12 **Q58. Does the CCAA pricing and annual reconciliation provide adequate protection**
13 **for the Company's other customers?**

14 A58. Yes. The CCAA pricing and associated reconciliation processes ensure that the
15 Customer fully pays for the actual costs of the energy storage and renewable energy
16 projects. In this way, the CCAA prevents cross-subsidization of the projects and
17 mitigates the risk of stranded assets.

18

19 **Clean Capacity Accelerator Agreement – ZRC transfer**

20 **Q59. What are the key terms governing the transfer of ZRCs from the Customer to**
21 **the Company?**

22 A59. Under the CCAA, the Customer commits to transfer 300 MW of ZRCs to the
23 Company which the Company can then utilize to meet its capacity needs. The ZRCs
24 will be provided by the Customer for each MISO season from June 1, 2028 to May
25 31, 2033.

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1 In addition, the Customer has agreed to pay the Company an amount based on the
2 Financial Compensation Mechanism (“FCM”) that the Company is authorized to
3 receive for PPAs it enters into associated with clean energy projects. More
4 specifically, the Customer will pay the Company an amount equal to the ZRCs
5 transferred to the Company multiplied by MISO Cost of New Entry (“CONE”)
6 multiplied by the Company’s pre-tax weighted average cost of permanent capital
7 (“financial adder”). The Company is proposing that it be allowed to record this
8 amount as non-refundable income, like it does with the FCM.

9

10 **Clean Capacity Accelerator Agreement – Capacity Credits**

11 **Q60. What types of CCAA resources will receive capacity credits?**

12 A60. All resources addressed under the CCAA (i.e., energy storage projects, renewable
13 energy projects, and ZRCs transferred from the Customer) will receive capacity
14 credits. In the CCAA, capacity credits associated with energy storage projects and
15 ZRCs transferred from the Customer are referred to as “Clean Capacity Credits”
16 while capacity credits associated with renewable energy projects are referred to as
17 “Renewable Capacity Credits.”

18

19 **Q61. How are capacity credits calculated?**

20 A61. The Customer will receive capacity credits that vary based on the accredited
21 capacity of the resource (i.e., energy storage projects, renewable energy projects,
22 and ZRCs). As this is a capacity-based credit, the amount of the credit will be based
23 on the capacity portion of the D11 rate.

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Capacity credits will be calculated separately for each CCAA resource and separately for each billing period during the term of the CCAA. For a given billing period and a given resource, the capacity credit is determined using the following equation:

$$\text{Capacity Credit} = \text{Accredited Capacity} \times \left(\frac{\text{Adjusted Capacity Credit Rate}}{\text{Credit Rate}} \times \left(\frac{\text{Peak Demand}}{\text{Contract Capacity}} \right) + \frac{\text{MISO Net CONE}}{\text{CONE}} \times \left(1 - \frac{\text{Peak Demand}}{\text{Contract Capacity}} \right) \right)$$

where:

- “Accredited Capacity” means:
 - For an energy storage project, the number of ZRCs assigned to that project in the MISO Planning Resource Auction (“PRA”) for Zone 7
 - For a renewable energy project or ZRCs transferred from the Customer, the number of ZRCs assigned to that project in the MISO PRA for the applicable zone
- “Adjusted Capacity Credit Rate” is determined using the following equation:

$$\frac{\text{Adjusted Capacity Credit Rate}}{\text{Credit Rate}} = \left(\frac{\text{D11 Capacity Rate}}{1 + \text{PRM}} \right)$$

where:

- “D11 Capacity Rate” is defined by the Capacity Demand Charge contained within the D11 rate applicable for the billing period
- “PRM” is the Planning Reserve Margin that the Company is subject to for the given billing period

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- 1 • “Peak Demand” is the Customer’s measured on-peak demand during the
- 2 given billing period
- 3 • “Contract Capacity” is the contract capacity applicable during the given
- 4 billing period (i.e., 1,000 MW once the Load Ramp Completion Date is
- 5 achieved)
- 6 • “MISO Net CONE” is the value established by MISO for the given billing
- 7 period and applicable zone

8

9 Once the capacity credit has been calculated for a given project and a given billing
 10 period, the Company will compare that amount to the MISO capacity market
 11 revenues generated by that project during the billing period. The Company will then
 12 provide to the Customer as a capacity credit for each project the lower of 1) the
 13 calculated capacity credit, or 2) the capacity market revenues.

14

15 **Q62. How will the Company determine the amount of capacity market revenues**
 16 **generated by each CCAA project or ZRC during a billing period?**

17 A62. The Company will utilize the MISO settlements process to determine the amount
 18 of capacity market revenues generated by each project or ZRC during a billing
 19 period. The MISO settlements process allows for market revenues and charges to
 20 be identified by their source. As such, the Company will be able to determine the
 21 specific market revenues and charges that were generated by each project or ZRC.

22

23 **Q63. What happens if the capacity market revenues generated by a project exceed**
 24 **the calculated capacity credit for that project during a billing period?**

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No.

1 A63. As described above, if capacity market revenues generated by a project for a billing
2 period exceed the calculated capacity credit for that project, the Company will
3 provide to the Customer the calculated capacity credit. The difference (i.e., capacity
4 market revenues less calculated capacity credit) is a benefit to the Company's other
5 customers that will be realized through the PSCR mechanism.

6

7 **Q64. What happens if the calculated capacity credit for a project exceeds the**
8 **capacity market revenues generated by that project during a billing period?**

9 A64. As described above, if capacity market revenues generated by a project for a billing
10 period are less than the calculated capacity credit for that project, the Company will
11 provide to the Customer the capacity market revenues. In this way, the Company's
12 other customers are protected because the credits being provided to the Customer
13 for a billing period will never be more than the capacity market revenues generated
14 by that project.

15

16 **Q65. Who will manage the operations of the projects deployed under the CCAA and**
17 **their participation in the MISO capacity market?**

18 A65. The Company will operate and manage the CCAA projects and transferred ZRCs,
19 including their participation in the MISO wholesale markets as the MISO Market
20 Participant. The projects deployed under the CCAA will be operated in a manner
21 similar to other Company resources.

22

23 **Q66. How will the capacity credits be provided to the Customer?**

24 A66. The capacity credits will be provided to the Customer through their monthly
25 invoice.

Line
No.

1 **Q67. Will the Company recover from the Customer the incremental costs of**
2 **Company activities associated with being the MISO Market Participant for**
3 **the CCAA resources in the wholesale capacity market?**

4 A67. Yes. The Company will recover its incremental costs related to the management of
5 the CCAA projects and ZRCs in the MISO wholesale capacity markets through an
6 administrative fee applied to the Customer's monthly invoice. This fee is consistent
7 with resource specific special contracts, including other VGP special contracts, that
8 have been approved for other customers.

9

10 **Clean Capacity Accelerator Agreement – Renewable Generation Credits**

11 **Q68. What type of CCAA projects will receive Renewable Generation Credits?**

12 A68. Only renewable energy projects deployed under the CCAA will receive Renewable
13 Generation Credits.

14

15 **Q69. How are the Renewable Generation Credits calculated?**

16 A69. The Customer will receive Renewable Generation Credits based on the generation
17 of the renewable energy projects that have been deployed under CCAA. As this is
18 an energy-based credit, the amount of the credit will be based on the energy portion
19 of the D11 rate.

20

21 Renewable Generation Credits will be calculated separately for each renewable
22 energy project and separately for each billing period during the term of the CCAA.
23 For a given billing period and a given renewable energy project, the Renewable
24 Generation Credit is determined using the following equation:

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1

Renewable Generation Credit =

$$\text{Project Generation} \times \left(\frac{(\text{D11 On-Peak Rate} \times \text{On-Peak Hours}) + (\text{D11 Off-Peak Rate} \times \text{Off-Peak Hours})}{\text{Total Hours}} \right)$$

2

3

Where:

4

- “Project Generation” is the actual generation of the renewable energy project during the billing period

5

6

- “D11 On-Peak Rate” and “D11 Off-Peak Rate” are defined by the Non-Capacity Energy Charge portion of the D11 rate applicable to the billing period

7

8

9

- “On-Peak Hours” is the number of on-peak hours during the billing period as defined by the D11 rate

10

11

- “Off-Peak Hours” is the number of off-peak hours during the billing period as defined by the D11 rate

12

13

- “Total Hours” is the total hours during the billing period

14

15

Once the Renewable Generation Credit has been calculated for a given project and a given billing period, the Company will compare that amount to the revenues generated by that project during the billing period in the MISO energy and operating reserve markets. Similar to the capacity credit, the Company will then provide to the Customer as a Renewable Generation Credit for each project the lower of 1) the calculated Renewable Generation Credit, or 2) the energy market revenues.

16

17

18

19

20

21

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No.

1 **Q70. How will the Company determine the amount of energy market revenue**
2 **generated by each renewable energy project during a billing period?**

3 A70. The Company will utilize the MISO settlements process to determine the amount
4 of energy market revenues generated by each renewable energy project during a
5 billing period. The MISO settlements process allows for market revenues and
6 charges to be identified by their source. As such, the Company will be able to
7 determine the specific energy market revenues that were generated by each
8 renewable energy project.

9

10 **Q71. What happens if the energy market revenues generated by a project exceed**
11 **the calculated Renewable Generation Credit for that project during a billing**
12 **period?**

13 A71. As described above, if energy market revenues generated by a project for a billing
14 period exceed the calculated Renewable Generation Credit for that project, the
15 Company will provide to the Customer the calculated Renewable Generation
16 Credit. The difference (i.e., energy market revenues less calculated Renewable
17 Generation Credit) is a benefit to the Company's other customers that will be
18 realized through the PSCR mechanism.

19

20 **Q72. What happens if the calculated Renewable Generation Credit for a project**
21 **exceeds the renewable generation market revenues generated by that project**
22 **during a billing period?**

23 A72. As described above, if energy market revenues generated by a project for a billing
24 period are less than the calculated Renewable Generation Credit for that project,
25 the Company will provide to the Customer the energy market revenues. In this way,

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1 the Company's other customers are protected because the credits being provided to
2 the Customer for a billing period can never be more than the energy market
3 revenues generated by that project.

4

5 **Q73. Who will manage the operations of the renewable energy projects deployed**
6 **under the CCAA and their participation in the MISO energy market?**

7 A73. The Company will operate and manage renewable energy projects deployed under
8 the CCAA, including managing their participation in the MISO wholesale markets
9 as the MISO Market Participant. The projects deployed under the CCAA will be
10 operated in a manner similar to other Company resources.

11

12 **Q74. How will the Renewable Generation Credits be provided to the Customer?**

13 A74. The Renewable Generation Credits will be provided to the Customer through their
14 monthly invoice.

15

16 **Q75. Will the Company recover from the Customer the incremental costs of**
17 **Company activities associated with being the MISO Market Participant for**
18 **the renewable energy projects in the wholesale energy markets?**

19 A75. Yes. The Company will recover its incremental costs related to the management of
20 the renewable energy projects in the MISO wholesale energy markets through an
21 administrative fee applied to the Customer's monthly invoice. This fee is consistent
22 with resource specific special contracts, including other VGP special contracts, that
23 have been approved for other customers.

Line
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1 **Clean Capacity Accelerator Agreement – Termination and Termination Payment**

2 **Q76. Can the Customer voluntarily terminate the CCAA?**

3 A76. No. The Customer cannot voluntarily terminate the CCAA. If the CCAA is
4 terminated through a customer default, the Customer is obligated to pay the
5 Company a termination payment.
6

7 **Q77. How is the termination payment calculated?**

8 A77. The termination payment is set equal to the unrecovered portion of each project's
9 costs (i.e., revenue requirement) over its respective depreciable life. In other words,
10 the termination equals the remaining amount that the Company would have
11 collected had the agreement not been terminated.
12

13 **Q78. How does the termination payment protect the Company's other customers?**

14 A78. The termination payment is designed to collect whatever amounts would have
15 otherwise been collected had the CCAA not been terminated. As such, the costs of
16 all CCAA projects would be fully recovered from the Customer, mitigating the risk
17 of stranded assets for these projects.
18

19 **Clean Capacity Accelerator Agreement – Credit and Collateral Requirements**

20 **Q79. Does the CCAA include credit and collateral requirements?**

21 A79. Yes. The CCAA includes credit and collateral requirements through a parent
22 guaranty and, if necessary based on the parent's credit rating, a letter of credit
23 designed to protect the Company and its customers in the event of Customer
24 default.

Line
No.

1 Specifically, once the CCAA is approved the Customer will initially provide a PG
2 to cover a portion of the Customer's financial obligations under the CCAA. Later
3 in the contract term, the PG is reduced once the forecasted termination payment of
4 the CCAA drops below the initial PG and a larger PG becomes superfluous. If at
5 any point the Customer's parent's credit rating drops below a pre-defined threshold,
6 then the Customer will be required to post a LoC equal the PG amount applicable
7 at that time.

8

9 **Regulatory Treatment**

10 **Q80. Would Commission approval of the Contracts increase the Company's cost of**
11 **service or customer rates?**

12 A80. No. Commission approval of the proposed Contracts does not increase the
13 Company's cost of service or customer rates. Instead, the proposed Contracts
14 govern how the Customer's future load will be served and how a portfolio of
15 projects will be deployed under the CCAA. Moreover, as discussed by Witness
16 Willis, the aggregate benefits of the Contracts, including both revenues received
17 from the Customer and avoided costs realized through the Contracts, will more than
18 offset any potential future cost of service increases and result in a customer benefit
19 of \$1.7 billion over the life of the contract. Importantly, the PSA establishes that if
20 in the future the aggregate benefits do not outweigh the costs, the Customer will
21 pay the difference.

22

23 **Q81. Will the Contracts be reflected in future regulatory filings?**

24 A81. Yes. If approved, the Contracts would be reflected in future general rate cases,
25 PSCR (plan and reconciliation) cases, and REP (plan and reconciliation) cases.

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No.

1 **Q82. How will the PSA and CCAA be incorporated into future rate cases?**

2 A82. The Contracts will be incorporated into future general rate cases in several ways,
3 including:

- 4 • The Customer's expected load will be incorporated into the Company's load
5 forecast that is used, for example, to determine present revenues, determine
6 cost allocations, and calculate rates;
- 7 • The Company owned energy storage projects deployed under the CCAA
8 will be proposed to be added to the Company's rate base as those projects
9 will be owned by the Company; and
- 10 • The amounts collected from the Customer through the CCAA for energy
11 storage projects will be incorporated to offset the additional rate base costs
12 from those energy storage projects.

13

14 The energy storage portfolio project costs that are added to the Company's rate base
15 will be fully offset by the amounts collected from the Customer through the CCAA.

16

17 **Q83. How will the PSA and CCAA be incorporated into future PSCR plans and**
18 **reconciliation cases?**

19 A83. As described above, the portfolio of energy storage projects, renewable energy
20 projects, and ZRCs deployed by the Company under the CCAA will be managed
21 by the Company as the MISO Market Participant. As such, these projects and ZRCs
22 will generate MISO revenues that would be reflected in future PSCR plan and
23 reconciliation filings.

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1 Capacity credits and Renewable Generation Credits paid to the Customer will also
2 be reflected in PSCR cases. This credit is similar to how VGP credits are reflected
3 in PSCR cases for the Company's MIGreenPower and VGP Special Contracts.
4

5 **Q84. How will the PSA and CCAA be incorporated into future REP plans and**
6 **reconciliation cases?**

7 A84. In accordance with the order in Case No. U-21990, the Company will file its next
8 Amended REP alongside its IRP later this year. As part of the IRP process, the
9 Company will assess potential incremental additions to its renewable portfolio and
10 develop an optimized strategy to support RPS compliance. As described by Witness
11 Bilyeu, the 2026 IRP will detail DTE Electric's approach to maintaining RPS
12 compliance. The 2026 Amended REP will further define these plans, detailing DTE
13 Electric's renewable energy credit acquisition strategy and further ensuring
14 compliance with RPS targets.
15

16 **Summary of Requested Commission Action**

17 **Q85. Can you summarize the Commission action that the Company is seeking**
18 **through the instant case?**

19 A85. Yes. The Company is seeking the Commission's approval of the following:

- 20 • PSA
- 21 • CCAA
- 22 • Ability of the Company to record Regulatory Liabilities during the term of
- 23 the CCAA related to the accelerated recovery (i.e., customer collections
- 24 above revenue requirement) of energy storage and renewable energy

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- 1 projects deployed under the CCAA; the Regulatory Liability would be
- 2 recorded to Account 254
- 3 • Ability to record the financial adder related to the transferred ZRCs
- 4 addressed in the CCAA as non-refundable income
- 5
- 6 **Q86. Does this complete your direct testimony?**
- 7 A86. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of)
DTE ELECTRIC COMPANY)
for Approval of Special Contracts)
and for other relief)

Case No. U-22058

REBUTTAL TESTIMONY

OF

NEAL T. FOLEY

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF NEAL T. FOLEY

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No.

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

3 A1. My name is Neal Foley. My business address is One Energy Plaza, Detroit,
4 Michigan 48226. I am employed by DTE Electric Company (“DTE Electric” or
5 “Company”).

6

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

9 A2. Yes.

10

11 **Part I: Purpose of Testimony**

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

13 A3. The purpose of my rebuttal testimony is to respond to certain positions taken by
14 Michigan Public Service Commission Staff (“Staff”) Witnesses Isakson and
15 Simpson; Attorney General (“AG”) Witness Coppola; Michigan Environmental
16 Council, Natural Resources Defense Council, and Sierra Club (“MNS”) Witness
17 Woods; Association of Businesses Advocating Tariff Equity (“ABATE”) Witness
18 Dauphinais; the Michigan Energy Innovation Business Council, Institute for
19 Energy Innovation, Ecology Center, Environmental Law & Policy Center, Union
20 of Concerned Scientists, and Vote Solar (“MEICEO”) Witnesses Kenworthy,
21 Sherman, and Hotaling; and Great Lakes Renewable Energy Association
22 (“GLREA”) Witness Richter.

23

24 I will address intervenor positions related to the following:

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- 1 • Protections for the Company’s other customers, including in the event of
- 2 Google LLC’s (“the Customer”) default and/or contract termination;
- 3 • Affordability backstop and the capture of benefits
- 4 • Ongoing reporting recommendations related to serving the Customer;
- 5 • Accounting treatment of the Zonal Resource Credit (“ZRC”) product
- 6 “financial adder”;
- 7 • Deployment of energy storage projects and renewable energy projects under
- 8 the Clean Capacity Accelerator Agreement (“CCAA”);
- 9 • Extension of the ZRC product and Rider 12 (“R12”) Demand Response
- 10 (“DR”) agreement; and
- 11 • ZRC product alternatives;

12

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

14 A4. Yes. I am sponsoring the following exhibit:

<u>Exhibit</u>	<u>Description</u>
A-22	PSA Amendment

17

18 **Q5. Was this exhibit prepared by you or under your direction?**

19 A5. Yes.

20

21 **Part II: Customer Protections**

22 **Q6. What Staff and intervenor positions related to customer protections are you**
23 **addressing?**

24 A6. I will address the following Staff and intervenor positions related to customer
25 protections:

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- 1 • The position taken by various intervenors that the Company should bear the
- 2 risk of the Primary Service Agreement (“PSA”) and CCAA collateral being
- 3 insufficient to cover the Customer’s obligations;
- 4 • AG Witness Coppola’s recommendation to increase the Minimum Billing
- 5 Demand (“MBD”) to 90% and increase the termination payment to 100%
- 6 of total demand costs for the full term of the PSA;
- 7 • ABATE Witness Dauphinais’ proposal that the PSA should be modified to
- 8 allow the termination payment to be adjusted at the time of termination; and
- 9 • ABATE Witness Dauphinais’ proposal that the Company commit “to fully
- 10 utilize the discretion given to it under Section 2 of the PSA” (page 26);

11

12 **Q7. Can you summarize Staff and intervenor positions related to PSA and CCAA**
 13 **collateral potentially being insufficient to cover the Customer’s obligations?**

14 A7. Yes. Staff Witness Isakson, AG Witness Coppola, and ABATE Witness
 15 Dauphinais all address the potential of the PSA’s and/or CCAA’s collateral
 16 requirements being insufficient to cover the Customer’s obligations under those
 17 agreements.

18

19 Witness Isakson cited the Commission’s guidance in its December 18, 2025, Order
 20 in Case No. U-21990 (“December 2025 Order”) which stated:

21

22 “...in the event of a failure to pay the MBD under the PSA, or in the event of a
 23 termination, default, or other event whereby DTE Electric is required to draw
 24 on the letter of credit or parental guaranty, if the company determines that the
 25 specified collateral is not sufficient to cover the full amount of the remaining

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1 financial exposure associated with the [Energy Storage Agreement] or the PSA
2 (minus the value to customers), the Commission specifically cautions DTE
3 Electric that any unrecovered costs shall not be borne by ratepayers and that
4 DTE Electric bears responsibility for any remaining liability. All risk associated
5 with the sufficiency of the collateral shall be borne by DTE Electric.” (page 41)

6

7 Witness Isakson recommends that the Commission make the same determination
8 in the instant case (page 20).

9

10 Witness Dauphinais appears in agreement with Witness Isakson and argues that
11 “given DTE will be the party managing the form and level of collateral for Google
12 for the PSA and CCAA, DTE is the party that should be at risk if Google’s collateral
13 proves insufficient, not DTE’s other customers” (pages 22-23). He likewise cites
14 the Commission’s guidance in its December 2025 Order and recommends that:

15

16 “To the extent the Commission grants approval of the PSA and CCAA, that
17 approval should be made conditional on DTE agreeing that in the event of a
18 failure by Google to pay any amount due to DTE under the PSA or CCAA, or
19 in the event of a termination, default, or other event whereby DTE is required
20 to draw on the letters of credit or parental guaranties under the PSA or CCAA,
21 if DTE determines that the specified collateral is not sufficient to cover the full
22 amount of the remaining financial exposure associated with the PSA or CCAA
23 (minus the value to customers), any unrecovered costs shall not be borne by
24 ratepayers and DTE shall bear responsibility for any remaining liability.” (page
25 24)

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1 On the same topic, Witness Coppola argues that for the PSA “the parent company
2 guaranty needs to be at the level that ensures full payment of the Customer’s total
3 obligations. The Company and other customers should not be at risk to absorb any
4 shortfall in costs for which the Customer and its parent are responsible” (page 15).
5 Witness Coppola makes the same recommendation with respect to the CCAA (page
6 20).

7

8 Witness Coppola recommends that the Commission remove any limit to the PSA
9 and CCAA collateral (page 15 for PSA; page 20 for CCAA).

10

11 **Q8. What is the Company’s response to these Staff and intervenor positions**
12 **related to PSA and CCAA collateral potentially being insufficient to cover the**
13 **Customer’s obligations?**

14 A8. To start, the Company acknowledges the Commission’s guidance in its December
15 2025 Order and notes it accepted the Commission’s conditions through its January
16 15, 2026 letter in the same docket.

17

18 As it pertains to this case, in the highly unlikely event of a Customer bankruptcy or
19 other circumstance in which recovery from the Customer, its parent guarantor, and
20 letters of credit is not sufficient, DTE Electric’s position is that it would not seek to
21 recover from other customers costs that are ultimately determined by the
22 Commission, pursuant to Section 5.1.3 of the PSA, to be in excess of the combined
23 revenues payable to the Company under the PSA and Related Agreements.

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1 As such, the Company acknowledges that it bears the risk of collateral insufficiency
2 for costs that the Commission ultimately determines in excess of revenues
3 received under the PSA, CCAA, and other related agreements.
4

5 **Q9. Can you summarize AG Witness Coppola's recommendations related to the**
6 **MBD and termination payment?**

7 A9. Yes. As it pertains to the MBD, Witness Coppola argues that because of the 80%
8 MBD, if the Customer uses less than 800 MW, then the Customer will be billed at
9 800 MW and "the Company must sell the 200 MW of excess capacity at a value
10 potentially lower than the cost of acquiring the capacity. The cost differential could
11 negatively impact other customers" (page 13). He further suggests that the 90%
12 level used as the Customer's load factor assumption in the Company's modeling is
13 a reasonable level for the MBD.
14

15 As it pertains to the termination payment, Witness Coppola characterizes the PSA
16 termination payment as being "based on the 80% Minimum Monthly Charge for
17 the remaining years of the PSA with no further obligation by the Customer after 17
18 years" (page 13). He argues that "the remaining 20% would be absorbed by other
19 customers if the Company is not able to find a replacement customer to take the
20 capacity" (page 13). He concludes that the termination payment should therefore
21 be based on 100% of total demand for the full term of the PSA (page 14).
22

23 **Q10. Does the Company agree with AG Witness Coppola's recommendations**
24 **related to the MBD and termination payment?**

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1 A10. No. As it pertains to the MBD, the proposed 80% MBD is aligned with prior
2 Commission guidance. Specifically:

- 3 • In Case No. U-21859, the Commission ordered the establishment of a Large
4 Load Customer Provision for Consumers Energy which included an 80%
5 MBD
- 6 • In Case No. U-21990, the Commission approved special contracts for a
7 large load customer which included an 80% MBD

8

9 As it pertains to the termination payment, the Company disagrees with Witness
10 Coppola's assertion that there is no termination payment obligation after 17 years.
11 Under Section 7.3 of the PSA the Customer is responsible for a termination
12 payment that provides 15 years of Minimum Monthly Charges ("MMC") calculated
13 based on the Customer's full load ramp. However, Section 7.3(3) of the PSA
14 additionally requires that the Customer pay a termination fee equal to the lesser of
15 24 months of MMCs or the number of months remaining in the contract term if the
16 PSA is terminated after the 13th anniversary of the Load Ramp Completion Date.
17 The Company notes that the as-filed PSA contained a drafting error in section
18 7.3(3) which referenced "Commencement Date" rather than the "Load Ramp
19 Completion Date", however, that error has been corrected. See Exhibit A-22.

20

21 Further, the proposed termination payment is aligned with prior Commission
22 guidance. Specifically:

- 23 • In Case No. U-21859, the Commission ordered the establishment of a Large
24 Load Customer Provision for Consumers Energy which included a

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1 termination payment (called an “Exit Fee”) that starts based on 15 years of
2 MBD and reduces over the term of the contract

3 • In Case No. U-21990, the Commission approved special contracts for a
4 large load customer which included a termination payment that starts based
5 on 10 years of MBD and reduces over the term of the contract

6

7 Witness Coppola advocates for a change from Case No. U-21859 by arguing
8 that in Case No. U-21859 there were no details regarding the impact of
9 termination payments and collateral requirements in that case (page 15).

10

11 The Company disagrees with this assertion since the Commission and other
12 parties in Case No. U-21859 could have estimated the impact of various MBDs
13 and termination payments for a hypothetical hyperscale data center.

14

15 Witness Coppola justifies a change from Case No. U-21990 on the basis that it
16 was an ex parte process (page 16). However, the financial impacts were
17 presented in public testimony and the contracts were fully audited by the
18 Commission and Staff.

19

20 **Q11. Can you summarize ABATE Witness Dauphinais’ recommendation that the**
21 **termination payment be modified at the time of termination?**

22 A11. Yes. ABATE Witness Dauphinais argues that the affordability backstop “appears
23 to not extend beyond termination of the PSA and does not provide for modification
24 of the termination payment under the PSA in the event the Commission finds the
25 aggregate costs of serving Google exceed the aggregate benefits from serving

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1 Google as a result of termination” (page 21). He therefore recommends that
2 approval of the PSA and CCAA:

3

4 “...should be made conditional on DTE and Google modifying the
5 Affordability Backstop (Section 5.1.3 of the PSA) to allow an evaluation and
6 modification of the termination payment by the Commission based on the facts
7 and circumstances known or knowable at the time of termination of the PSA to
8 ensure the costs incurred to serve Google do not exceed the benefits from
9 serving Google due to the termination, giving full consideration to the
10 reasonably projected forward looking benefits at that time from any sunk costs
11 incurred by DTE to serve Google.” (page 22)

12

13 **Q12. Does the Company agree with ABATE Witness Dauphinais’ recommendation**
14 **that the termination payment be modified at the time of termination?**

15 A12. No, because such a modification is unnecessary. As it pertains to the CCAA, the
16 termination payment is set equal to the remaining revenue requirement of the
17 energy storage and renewable energy projects deployed under that agreement that
18 have not yet been recovered from the Customer. As such, the termination payment
19 automatically adjusts to account for the costs of those projects and ensures that the
20 Customer will fully pay for each project’s revenue requirement over the project’s
21 depreciable life.

22

23 As it pertains to the PSA, the termination payment is based on the MBD and not on
24 an assessment of specific costs or benefits of serving the Customer. As discussed

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1 previously in my rebuttal testimony, this approach is consistent with the following
2 previous Commission guidance:

- 3 • In Case No. U-21859, the Commission ordered the establishment of a Large
4 Load Customer Provision for Consumers Energy which included a
5 termination payment (called an “Exit Fee”) that starts based on 15 years of
6 MBD and reduces over the term of the contract
- 7 • In Case No. U-21990, the Commission approved special contracts for a
8 large load customer which included a termination payment that starts based
9 on 10 years of MBD and reduces over the term of the contract

10

11 Witness Dauphinais offers no argument for why the Commission’s Orders in these
12 cases were incorrect.

13

14 Additionally, the Company notes that the termination payment is not static and is
15 calculated at the time a termination occurs. It is a function of the tariffs and rates
16 that the Customer is subject to, which are determined in a rate case by Commission
17 approval. Rates or tariffs may change and the Commission maintains oversight over
18 these activities, and it therefore maintains oversight over the rates that underpin the
19 termination payment.

20

21 Furthermore, Witness Dauphinais’ suggestion that the Commission modify the
22 termination payment to leave it open ended and at the discretion of the Commission
23 at termination is not commercially reasonable and would prevent the Customer
24 from being able to reasonably assess its potential future liabilities.

Line
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1 **Q13. Can you summarize ABATE Witness Dauphinais' recommendation related to**
2 **the Company fully using its discretion under Section 2 of the PSA?**

3 A13. Yes. First, Witness Dauphinais characterizes Section 2 of the PSA as giving "DTE
4 the reasonable discretion to limit Google's load ramp or max load when the triggers
5 apply" (page 25) but goes on to argue that "there is no obligation on DTE to fully
6 utilize that provision to protect resource adequacy for DTE's other customers"
7 (page 25). He therefore recommends that DTE commit "to fully utilize the
8 discretion given to it under Section 2 of the PSA to limit the load ramp and
9 maximum demand of Google as necessary to ensure resource adequacy for DTE's
10 other customers" (page 26).

11

12 **Q14. Does the Company agree with ABATE Witness Dauphinais'**
13 **recommendation?**

14 A14. No, because it is unclear what it means in practice. Specifically, Witness
15 Dauphinais provides no detail on what it means for the Company to "fully utilize
16 the discretion given to it in his recommendation versus exercising the "reasonable
17 discretion" that he admits Section 2 of the PSA provides the Company. It is unclear
18 why the Company needs to exercise more than reasonable discretion and Witness
19 Dauphinais provides no additional detail.

20

21 Further, Witness Dauphinais provides no detail as to what is intended by the
22 suggestion that the Company "fully utilize that provision to protect resource
23 adequacy." In addition to Section 2 of the PSA, once approved by the Commission
24 the Customer will be subject to the amended Emergency Electric Procedures in the

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1 Company's Rate Book, which will require firm load shedding prior to other
2 customers.

3

4 **Part III: Affordability Backstop**

5 **Q15. What intervenor positions related to the affordability backstop are you**
6 **addressing?**

7 A15. I will address the following intervenor positions related to the affordability
8 backstop:

- 9 • MEICEO Witness Kenworthy's recommendations related to the mechanics
10 of the affordability backstop;
- 11 • MEICEO Witness Kenworthy's and AG Witness Coppola's
12 recommendations related to the tracking of transmission costs;
- 13 • MEICEO Witness Kenworthy's suggestion that the Commission should
14 address the time period over which its "no-cost-shift requirement is
15 satisfied"; and
- 16 • AG Witness Coppola's recommendation to establish a regulatory liability
17 to capture customer benefits

18

19 **Q16. Can you summarize MEICEO Witness Kenworthy's recommendations**
20 **related to the mechanics of the affordability backstop?**

21 A16. Yes. Witness Kenworthy argues that the affordability backstop provision of the
22 PSA does not "specify how or when the Commission would test that question, what
23 metrics, modeling, or reporting would inform the underlying findings of fact, or on
24 what cadence such a review would occur." (page 37).

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1 Witness Kenworthy then makes a series of recommendations related to “reporting,
2 verification, and true-up procedures that make the affordability backstop
3 operational and enforceable over the full 20-year term” (page 41). These
4 recommendations include (pages 41-42):

- 5 • Measurable triggers tied to the specific assumptions underlying Exhibit A-
6 19;
- 7 • A defined remedy if those triggers are breached, including a true-up or claw-
8 back to the Customer rather than to other ratepayers;
- 9 • A sunset/reopener mechanism tied to the Integrated Resource Plan (“IRP”)
10 cadence;
- 11 • Reporting obligations sufficient for the Commission and parties to verify
12 performance over the life of the contract;
- 13 • Cadence – most naturally the IRP cadence – with required interim reporting
- 14 • A properly maintained “without-customer” counterfactual baseline;
- 15 • Actual “but-for” analysis being performed in the Company’s general rate
16 cases and its next IRP;
- 17 • Running the IRP with and without the Customer load; and
- 18 • Demonstration that the Company evaluated and, where cost-effective,
19 pursued the opportunities CEO Witness Sherman identified

20

21 **Q17. Does the Company agree with MEICEO Witness Kenworthy’s**
22 **recommendations?**

23 A17. The Company agrees that certain reporting obligations will be required for the
24 application of Section 5.1.3 of the PSA (the affordability backstop). As described
25 in my Revised Direct Testimony (page 21) and as required under Section 5.1.3, the

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1 Company intends to report the aggregate costs and benefits (i.e., revenues and
2 avoided costs) in rate cases and PSCR proceedings. The contents and cadence of
3 this reporting are discussed further in Part IV below. To the extent that Witness
4 Kenworthy is suggesting that Section 5.1.3 of the PSA be modified to include
5 reporting metrics, the Company disagrees. That section already includes a broad
6 acknowledgement that “the combined revenues received by the Company under
7 this Agreement and the applicable Related Agreements along with any avoided
8 costs attributable to Google should be considered in regulatory proceedings
9 applicable to Company’s cost to serve Customer, and the Parties shall act in good
10 faith to ensure such combined revenues and avoided costs are presented in such
11 proceedings to the extent applicable.”

12

13 On the question of “how” the Commission would test for an affordability benefit,
14 Section 5.1.3 also establishes that the relevant test is comparing the costs to serve
15 the customer’s load to the combination of revenues received and avoided costs.
16 Further details need not be written into the PSA as they can be addressed outside
17 of the agreement. In general, the Company envisions that future aggregate cost and
18 benefit reporting for the Customer may incorporate the following as applicable:

- 19 • The revenue requirement of energy storage projects deployed under the
20 CCAA
- 21 • The revenue requirement of renewable energy projects deployed under the
22 CCAA
- 23 • The revenue requirement of renewable energy projects deployed to meet the
24 Company’s Renewable Portfolio Standard (RPS) obligations not covered
25 by the CCAA

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- 1 • The revenue requirement of other resources that may be identified in the
- 2 IRP as being caused by the Customer's load
- 3 • Increased fuel and purchased power costs
- 4 • The revenue requirement of transmission investments
- 5 • Avoided costs realized through the contracts, including any revenue
- 6 requirement associated with resources that the Company was able to avoid
- 7 deploying due to serving the Customer's load under the PSA and CCAA.

8

9 On the question of "when" the Commission would test for an affordability benefit,
10 Section 5.1.3 states that costs and benefits "should be considered in regulatory
11 proceedings applicable to Company's cost to serve Customer." In particular, the
12 Company envisions combined revenues and avoided costs will be presented in
13 general rate case filings and PSCR filings, both of which are contested proceedings.
14 The Company will present an accounting of the aggregate benefits and costs of
15 serving the Customer's load.

16

17 Witness Kenworthy does not seem to reconcile his suggested affordability backstop
18 mechanics with the language of PSA Section 5.1.3. For example, he suggests the
19 affordability backstop should include "measurable triggers" such as 45Q credit
20 realization or the Customer's ZRC obligation (page 38). It is unclear how these
21 "triggers" would work in practice or how they fit into the contractual language of
22 Section 5.1.3.

23

24 **Q18. Can you summarize intervenor recommendations related to the tracking of**
25 **transmission costs?**

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1 A18. Yes. MEICEO Witness Kenworthy correctly captures on page 26 that there are two
2 dynamics at play as it relates to transmission cost changes related to serving the
3 Customer's load. Specifically:

- 4 • Increased costs driven by transmission upgrades required to serve the
5 Customer's facility; and
- 6 • Increased allocation of costs from ITC due to the Customer's contribution
7 to the Company's load

8

9 Given these dynamics, Witness Kenworthy recommends that "DTE should be
10 required to report: (1) the actual ITC transmission upgrade costs associated with
11 serving the Customer; (2) how those costs are recovered through MISO schedules
12 and reflected in PSCR; (3) the portion of those costs paid by the customer through
13 D11 and PSCR charges; (4) the effect of the Customer's load on transmission
14 billing determinants and unit costs; and (5) whether, after accounting for both
15 incremental costs and revenues, other customers are held harmless" (page 30).

16

17 Likewise, AG Witness Coppola recommends that "the Commission direct the
18 Company to implement appropriate cost accounting tracking procedures to allow
19 complete and accurate reporting of all transmission-related incremental costs for
20 each new data center for presentation of the aggregate costs and benefits that are
21 impacting other customers" (page 25).

22

23 **Q19. Does the Company agree with intervenor recommendations related to the**
24 **tracking of transmission costs?**

Line
No.

1 A19. Partially. To start, the Company is committed to a transparent and accurate
2 accounting of costs to serve the Customer's load. Such an accounting is critical to
3 protecting customers from cost-shifts through the application of Section 5.1.3 of
4 the PSA (the affordability backstop).

5
6 As it relates to transmission costs, the Company can identify and report
7 transmission-related costs using the best available information, including actual or
8 estimated project capital costs for network upgrades and modeled transmission-
9 expense impacts associated with the Customer's load. However, transmission
10 charges are ultimately incurred and recovered on a system-wide basis through
11 charges established by the transmission provider and applicable tariffs, and the
12 Company is not billed by ITC for ratemaking purposes on a project-specific basis.
13 Thus, while the Company can provide reasonable estimates and supporting detail
14 for transmission-related costs associated with serving the Customer's load, it may
15 not be able to provide the precise project-by-project billing traceability implied by
16 some intervenor recommendations.

17
18 The Company disagrees with Witness Kenworthy's suggestion of reporting
19 "whether, after accounting for both incremental costs and revenues, other
20 customers are held harmless." Section 5.1.3 of the PSA relies on an accounting of
21 *aggregate* costs and benefits, and not individual line-item comparisons of each cost
22 and benefit component.

Line
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1 **Q20. Can you summarize MEICEO Witness Kenworthy’s suggestion that the**
2 **Commission should address the time period over which its “no-cost-shift**
3 **requirement is satisfied”?**

4 A20. Yes. Witness Kenworthy correctly captures that in the Company’s modeling of the
5 \$1.7 billion benefit to customers, there are four years out of the twenty years that
6 the Company is modeling a cost increase to customers. Witness Kenworthy
7 therefore argues “the existence of positive annual cost years demonstrates that the
8 Commission should address whether its no-cost-shift requirement is satisfied
9 annually, cumulatively, or through some defined true-up period” (page 22).

10

11 **Q21. What is the Company’s view related to MEICEO Witness Kenworthy’s**
12 **suggestion?**

13 A21. It is the Company’s view that the “no cost-shift requirement” must be satisfied over
14 the life of the special contracts. Through this proceeding, the Commission is
15 assessing contracts that last roughly 20 years and therefore any assessment of costs
16 and benefits must match the same period. Looking narrowly at individual years
17 could lead to making suboptimal decisions about the service to large load customers
18 and risks not realizing the benefits that can accrue to the Company’s other
19 customers.

20

21 The Company further highlights that Staff Witness Isakson confirmed on page 7 of
22 his testimony the Company’s assessment of net benefits remains positive over the
23 life of the contract even when using a conservative sensitivity (e.g., no 1.5% rate
24 escalation), in addition to Witness Kenworthy’s assessment that the net benefit on
25 a discounted basis remains nearly \$1 billion (page 21).

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1 **Q22. Can you summarize AG Witness Coppola’s recommendation to establish a**
2 **regulatory liability to capture affordability benefits?**

3 A22. Yes. Witness Coppola recommends that the Company establish a regulatory
4 liability to capture the annual financial benefits of serving the Customer. He argues
5 that “[t]his tracking mechanism will ensure that financial benefits are actually
6 passed through to customers and do not accrue to the benefit of the utility” (page
7 27).

8

9 **Q23. Does the Company agree with AG Witness Coppola’s recommendation to**
10 **establish a regulatory liability to capture affordability benefits?**

11 A23. No, such a mechanism is unnecessary. The benefits realized through serving the
12 Customer’s load will naturally flow to the Company’s customers through existing
13 processes. For example, benefits flowing through the PSCR will be realized
14 through a lower PSCR factor than would have otherwise been applied, and base
15 rate benefits arising from increased sales will support a lower revenue requirement
16 for other customers by offsetting a greater portion of the Company’s investments
17 in the grid and the transition to new generation sources (see Exhibit A-20, for
18 example).

19

20 Further, such a mechanism could delay the realization of benefits for the
21 Company’s other customers. The recording of a regulatory liability would need to
22 occur after the Customer’s usage occurs and then would need to be addressed in a
23 general rate case or separate accounting application before the benefit could be
24 passed to the Company’s customers. Allowing the affordability benefit to flow
25 through existing processes allows customers to realize the benefit faster, potentially

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1 in “real time” through, for example, the annual PSCR plan process and
2 establishment of the PSCR factor.

3

4 **Part IV: Reporting**

5 **Q24. What Staff and intervenor positions related to ongoing reporting are you**
6 **addressing?**

7 A24. I will address the following intervenor positions related to ongoing reporting:

- 8 • Staff Witness Simpson’s recommendation on combining large load
9 customers for future analysis; and
- 10 • Recommendations by Staff Witness Simpson, AG Witness Coppola,
11 MEICEO Witnesses Kenworthy and Hotaling, and GLREA Witness
12 Richter related to the frequency, information provided, and venue of
13 ongoing reporting.

14

15 **Q25. Can you summarize Staff Witness Simpson’s recommendation on combining**
16 **large load customers in future analysis?**

17 A25. Yes. Witness Simpson recommends that, as it relates to the Company’s next IRP,
18 Clean Energy Plan, or Amended Renewable Energy Plan (“REP”) filing, that “the
19 Commission adopt the same conditions that it directed in the December 18, 2025
20 order in that case, but that the analysis includes both of the Company’s large load
21 customers rather than performing a separate analysis for each large load customer”
22 (page 9).

23

24 **Q26. Does the Company agree with Staff Witness Simpson’s recommendation on**
25 **combining large load customers in future analysis?**

Line
No.

1 A26. No, because it conflicts with Section 5.1.3 of the PSA (the affordability backstop)
2 and previous Commission guidance. Section 5.1.3 of the PSA relies on a
3 presentation of the aggregate costs and benefits of serving the Customer load such
4 that the Commission can determine if the aggregate benefits exceed the aggregate
5 costs. As discussed previously in my rebuttal testimony, one element of the costs
6 of serving the Customer's load is the revenue requirement of resources identified
7 in the IRP as being caused by the Customer's load (and not being recovered through
8 the CCAA). As such, each Customer's load must be considered individually in the
9 IRP such that resource planning changes under each load sensitivity can be
10 identified. Combining large load customers would make such identification
11 impossible.

12

13 Further, the Commission's December 2025 Order directed the Company to
14 annually report on the "realization of the projected affordability benefit" (page 42)
15 for the large load customer in that case. Like the Customer in this case, the
16 Company can only provide the required reporting if it is able to identify, through
17 the IRP, what resources planning changes were caused by that customer's load.
18 Again, this requires large load customers to be considered individually, and not in
19 the aggregate.

20

21 **Q27. Can you summarize Staff and intervenor positions related to the frequency,**
22 **venue, and content of ongoing reporting?**

23 A27. Yes. The table below captures the various intervenor recommendations related to
24 ongoing reporting related to serving the Customer's load:

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1

Table 1 Staff and intervenor positions relating to ongoing reporting

Witness	Frequency	Reported Information	Venue
Simpson (Staff); page 15	Quarterly; starting June 30, 2027	• Customer's load profile for the previous quarter • Amount of renewable and storage that is operational under the CCAA as of the end of the quarter • Customer's total demand for the preceding 12 months, compared to the expected contract capacity and MBD • Any changes to the Customer's credit rating, as well as associated impacts to credit or collateral terms • Assessment of the financial state of the Customer	This docket
Simpson (Staff); page 15	Annually	• Realization of the affordability benefit	This docket
Coppola (AG); page 26	Annually	• Reconciliation of net benefits accruing to other customers from the Customer	Not identified
Kenworthy (CEO); page 39	IRPs w/ interim reporting	• Affordability backstop assessment (defined on page 38-39)	IRPs and this docket
Hotaling (CEO); page 18	Annually	• Customer's load materialization • Accreditation for resources under the CCAA and resources that will be pursued in 2033 when the Customer's ZRCs expire and the Customer no longer engages in the demand response program • Information relating to the cost and benefits from the Customer	This docket
Richter (GLREA); Page 27	Quarterly and annual reports consistent with order in Case No. U-21990		

2

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1 **Q28. What is the Company's position as it relates to the frequency, venue, and**
2 **content of ongoing reporting?**

3 A28. To start, the Company is committed to timely and transparent reporting on large
4 load customers but notes the lack of consistency across the intervening parties in
5 their recommendations. For example, Staff Witness Simpson and AG Witness
6 Coppola recommend that the realization of the affordability benefit should be
7 reported on annually, while MEICEO Witness Kenworthy argues the affordability
8 backstop should be addressed in the IRP with unspecified interim reporting in this
9 docket. MEICEO Witness Hotaling recommends annual reporting on the
10 Customer's load materialization, while Staff Witness Simpson recommends
11 quarterly.

12

13 Further, both Staff Witness Simpson and GLREA Witness Richter base their
14 recommendations on the Commission's December 2025 Order. However, as
15 discussed previously in Part III of my rebuttal testimony, the presence of PSA
16 Section 5.1.3 (the affordability backstop) in this case introduces new tracking and
17 reporting requirements, and therefore simply replicating what was done in Case No.
18 U-21990 will not satisfy Section 5.1.3.

19

20 After considering the intervening parties' positions, the Company believes the
21 proper tracking and reporting cadence includes the following:

- 22 • By April 15 of each year, the Company will provide a report covering the
23 previous calendar year. The Company does not take a view on the
24 appropriate docket for the report, but notes that Customer information is

Line
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considered confidential and will need to be protected as such. The report will contain:

- The Customer's load profile for the previous year;
 - The Customer's maximum demand for the previous year (by month) compared to the expected contract capacity and MBD;
 - The total MW of energy storage projects deployed under the CCAA that have achieved their Commercial Operations Date ("COD") by the end of the previous year;
 - The total MW of renewable energy projects deployed under the CCAA that have achieved their COD by the end of the previous year;
 - Any changes to the Customer's or its parent's credit rating; and
 - A presentation of the aggregate costs and benefits of serving the customer as of the end of the previous year; I provide additional detail of what would be included in such a presentation earlier in Part III of my rebuttal testimony
- Consistent with Section 5.1.3 of the PSA and my previous rebuttal testimony in Part III on the affordability backstop, during future rate cases and PSCR proceedings the Company would present aggregate costs and benefits of serving the Customer such that the Commission could determine if aggregate benefits exceed aggregate costs

The Company does not agree with Staff Witness Simpson's and GLREA Witness Richter's recommendation of quarterly reporting. Except during the Customer's ramp period, the information provided in the recommended report is not expected

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No.

1 to change meaningfully. And even during the ramp period, the value of receiving
2 this information every three months is unclear.

3

4 The Company also does not agree with Staff Witness Simpson's and GLREA
5 Witness Richter's recommendation to include an "Assessment of the financial state
6 of the Customer." The credit and collateral requirements of the PSA and CCAA
7 rely on publicly available credit ratings. The Company does not intend to perform
8 any ongoing financial assessment beyond reviewing these credit ratings.

9

10 The Company notes that while it supports the ongoing presentation of aggregate
11 costs and benefits, it also does not view MEICEO Witness Kenworthy's
12 recommended affordability backstop mechanics as necessary or beneficial, as I
13 discussed earlier in Part III of my rebuttal testimony.

14

15 The Company further notes that it addresses MEICEO Witness Hotaling's
16 recommendation to track energy storage accreditation values later in Part VI of my
17 rebuttal testimony.

18

19 **Part V: Accounting treatment of ZRC product "financial adder"**

20 **Q29. What Staff and intervenor positions related to the accounting treatment of the**
21 **ZRC product "financial adder" are you addressing?**

22 A29. I will address the positions taken by various intervenors that the Company's
23 proposed accounting treatment of the ZRC product "financial adder" should be
24 rejected.

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No.

1 **Q30. Can you summarize intervenor positions related to the Company’s proposed**
2 **accounting treatment of the ZRC product “financial adder”?**

3 A30. Yes. Staff Witness Simpson (page 14), ABATE Witness Dauphinais (page 29),
4 MEICEO Witness Sherman (page 46), and GLREA Witness Richter (page 28)
5 argue that the Company should not be allowed to record the financial adder as pre-
6 tax net income, and instead that the financial adder should either be rejected or be
7 treated as ordinary revenue used to offset the Company’s future revenue
8 deficiencies.

9
10 ABATE Witness Dauphinais provides an alternative recommendation that approval
11 be conditioned upon DTE Electric “agreeing that the Commission’s approval of
12 Google’s agreement to provide a financial incentive to the ZRC transfer does not
13 set any precedent with respect to whether DTE is entitled to mandate the receipt of
14 such a financial incentive from its customers on customer self-supplied capacity
15 and energy.” (page 29)

16
17 **Q31. Does the Company agree with the intervenor recommendations that the**
18 **Company not be allowed to record the financial adder as pre-tax income?**

19 A31. No. The financial adder is similar in concept to a Financial Compensation
20 Mechanism (“FCM”) in that it is intended to account for the opportunity cost of the
21 Company foregoing the development of a company-owned resource. As it is similar
22 in concept with a similar objective, it should receive the same accounting treatment.

23
24 The various recommendations related to the accounting of the financial adder
25 provide no factual or legal basis to deny the accounting treatment requested by the

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1 Company other than to suggest that an FCM is not appropriate because there is no
2 power purchase agreement (“PPA”) with the Customer. However, the Company is
3 not suggesting that the accounting treatment be granted pursuant to MCL 460.1028.
4 The financial adder is part of a special contract, which by its nature may contain
5 special terms and conditions. It is not tied to the statutory FCM.

6

7 Further, the intervenor positions work to establish an unfair and inequitable sharing
8 of risks and benefits related to the provision of service to the Customer through the
9 special contracts. All four intervenors that took a position on the accounting
10 treatment of the financial adder variously argued that the Company should bear the
11 risk of the Customer not fully covering their financial obligations. However, all
12 four also argued that the Company should not be allowed to offset that risk by
13 capturing the benefit of the financial adder that the Customer has agreed to pay.

14

15 Importantly, the financial adder is not offsetting a cost to the Company that it would
16 otherwise recover from its other customers. The Company’s customers would be
17 held harmless if the Commission were to grant the Company’s requested
18 accounting treatment. The position taken by intervenors to not allow the Company
19 to offset the risks it is taking by providing service under the special contracts (all
20 while holding other customers harmless) is unreasonable and inequitable.

21

22 The Company does however support ABATE Witness Dauphinais alternative
23 recommendation. If the Commission approves the accounting treatment, the
24 Company does not intend to rely on such approval as precedent for mandating a

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1 financial adder from future customers. Any such proposals would be addressed on
2 a case-specific basis.

3

4 **Part VI: Deployment of CCAA energy storage and renewable energy projects**

5 **Q32. What intervenor positions related to the deployment of energy storage and**
6 **renewable energy projects are you addressing?**

7 A32. I will address the following intervenor positions related to the deployment of energy
8 storage and renewable energy projects:

- 9 • MNS Witness Woods' recommendation that the Commission "condition its
10 approval of the Special Contracts on the requirement that the Company
11 deploy (and the Customer pay for) the full 1,600 MW [renewable energy]
12 and 480 MW [energy storage] goals and treat the goals as floors, not
13 ceilings." (page 37);
- 14 • MEICEO Witness Hotaling recommendation that the Commission "should
15 consider directing the Company to increase the cap on the energy storage
16 and renewable energy projects." (page 21); and
- 17 • Staff Witness Simpson's recommendation related to the procurement of
18 CCAA resources using the Competitive Procurement Guidelines (page 11)

19

20 **Q33. Can you summarize MNS Witness Woods' recommendation related to the**
21 **deployment of energy storage and renewable energy projects under the**
22 **CCA?**

23 A33. Yes. Witness Woods properly captures that the CCAA allows the Company to
24 deploy (and the Customer pays for) "up to" 480 MW of energy storage projects and

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1 “up to” 1,600 MW of renewable energy projects. Witness Woods argues this “all
2 but ensures” the Company will deploy less than those amounts (pages 20-21).

3
4 Witness Woods offers no reasoning for why it is necessary to deploy the full 480
5 MW of energy storage projects, but as it relates to renewable energy projects she
6 argues that “[i]f the Company deploys less than the 1,600 MW renewable energy
7 target, that will increase the Company’s RPS compliance obligations accordingly.”
8 (page 22)

9
10 **Q34. Does the Company agree with Witness Woods’ recommendation?**

11 A34. No. To start, the Company notes that its modeling presented in the instant case
12 assumes that only 450 MW of energy storage projects (of the maximum 480 MW)
13 are deployed. The 30 MW difference provides the Company with flexibility to
14 develop an energy storage portfolio of at least 450 MW while accounting for
15 potential variability in the size of projects that are bid into its energy storage RFP.
16 To be clear, the Company intends to deploy at least 450 MW and up to 480 MW of
17 energy storage. The Company notes that Witness Woods provided no justification
18 for why it is necessary to deploy the full 480 MW of energy storage.

19
20 As it relates to renewable energy projects, the Company intends to deploy the full
21 1,600 MW of renewable energy projects. Similar to energy storage, the “up to”
22 language provides the Company flexibility to account for potential variability in the
23 size of the projects that are available for deployment under the CCAA.

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1 The “up to” language is a commercially reasonable contract provision that reflects
2 the fact that renewable and energy storage projects are developed in discrete project
3 sizes and are subject to procurement, permitting, interconnection, cost, and
4 commercial-operation timing considerations. For renewable energy projects, the
5 Company intends to deploy the full 1,600 MW contemplated by the CCAA, but the
6 contract should not be converted into a commercially unreasonable requirement
7 that would force the Customer to accept resources that exceed the negotiated
8 quantity or otherwise fall outside the agreed commercial framework.

9
10 In addition, regardless of the specific amount of energy storage and renewable
11 energy projects that are deployed, PSA Section 5.1.3 (the affordability backstop)
12 will still be in effect, ensuring the Company’s other customers are protected.
13 Further, if the Company is unable to fully deploy the contemplated resources,
14 Section 2.4 of the PSA provides a mechanism for the Company and the Customer
15 to jointly identify an alternative solution, or to reduce the Customer’s load ramp
16 accordingly.

17

18 **Q35. Can you summarize MEICEO Witness Hotaling’s recommendation related to**
19 **the deployment of energy storage and renewable energy projects under the**
20 **CCAA?**

21 A35. Yes. Witness Hotaling argues that “DTE’s energy storage accreditation
22 assumption, in particular for the summer season, may introduce risk that the energy
23 storage in the CCAA is not sufficient [to reliably serve the Customer’s load]” (page
24 19), and therefore capping the amount of energy storage the Company can deploy

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1 at 480 MW “does not leave any flexibility for consideration of how the
2 accreditation of those resources might evolve over time” (page 20).

3
4 To account for this dynamic, Witness Hotaling suggests the Commission “should
5 consider directing the Company to increase the cap on the energy storage and
6 renewable energy projects” (page 21) so that “DTE could evaluate the RFP
7 responses and determine whether additional resources are economic under a range
8 of accreditation assumptions” (page 21).

9
10 **Q36. Does the Company agree with MEICEO Witness Hotaling’s recommendation?**

11 A36. No. The CCAA is designed such that the Company can deploy up to a certain
12 amount of nameplate capacity and is not designed to match the capacity needs of
13 the Customer. Instead, the Company’s IRP proceedings are designed to ensure the
14 Company has adequate system resources to reliably serve its *total* customer load.
15 Said differently, the Company does not deploy any one single type of resource to
16 meet the needs of any individual customer. The Company deploys a portfolio of
17 resources to optimally and reliably serve customers. As such, Witness Hotaling’s
18 recommendation runs counter to both the structure of the CCAA and to the way in
19 which the Company plans and deploys resources to reliably serve its total customer
20 load.

21
22 This conflict between Witness Hotaling’s recommendation and the way in which
23 the Company’s system planning works extends to her suggestion that ongoing
24 reporting “should include an ongoing evaluation of the Customer’s load and
25 accreditation of the resources in the CCAA and any incremental resources

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1 identified for the Customer. Including this in the reporting will ensure ongoing
2 monitoring of the accreditation risk and cost assignment that might be needed if
3 there is a significant change in resource accreditation” (page 21). Tracking the
4 accreditation of resources deployed under the CCAA will not provide insight into
5 what resources may or may not have been caused by the Customer’s load. Instead,
6 the full view of the Company’s resource adequacy outlook would be studied in an
7 IRP.

8

9 Furthermore, Witness Hotaling’s recommendation is not commercially reasonable.
10 It would prevent the Customer from being able to reasonably assess its potential
11 future liabilities as it would essentially be forcing the Customer to accept uncapped
12 liabilities related to the deployment of energy storage and renewable energy
13 projects.

14

15 With that said, the Company notes that regardless of the specific amount of energy
16 storage and renewable energy projects that are deployed, Section 5.1.3 of the PSA
17 (the affordability backstop) will be in effect, ensuring the Company’s other
18 customers are protected.

19

20 **Q37. Can you summarize Staff Witness Simpson’s recommendation related to the**
21 **procurement of CCAA resources using the Competitive Procurement**
22 **Guidelines?**

23 A37. Yes. Witness Simpson asserts that I testified that the Special Contract resources
24 will be procured through a request for proposal (“RFP”) following the Competitive
25 Procurement Guidelines and the Company’s 2022 IRP Settlement (page 11).

Line
No.

1 **Q38. Does the Company agree with this characterization of how resources under**
2 **the CCAA will be procured?**

3 A38. Not entirely. Page 25 of my revised direct testimony specifically concerns the
4 energy storage portfolio under the CCAA. In that section, I state that the Company
5 intends to issue an energy storage RFP to identify energy storage projects to be
6 deployed under the CCAA, and that the RFP will follow the MPSC Competitive
7 Procurement Guidelines and the 2022 IRP Settlement.

8
9 I then separately address renewable energy projects later in pages 26-27 of my
10 revised direct testimony. For those projects, I explain that the CCAA terms
11 governing renewable energy projects comply with the VGP Settlement
12 Agreements, that the renewable resources are considered part of a customer-
13 requested VGP Special Contract, and that renewable energy projects will be
14 selected consistent with the VGP Settlement Agreements, with the details of the
15 competitive process agreed upon with the Customer.

16
17 Thus, I did not testify that the renewable energy projects supporting the VGP
18 Special Contract would be procured through the same energy storage RFP or under
19 the 2022 IRP Settlement procurement framework.

20

21 **Part VII: Extension of ZRC product and R12 DR Agreement**

22 **Q39. What intervenor positions related to the extension of the ZRC product and the**
23 **R12 DR agreement are you addressing?**

Line
No.

1 A39. I will address ABATE Witness Dauphinais' and CEO Witness Hotaling's
2 recommendation that the ZRC product and the R12 DR agreement be extended
3 beyond May 31, 2033.

4
5 **Q40. Can you summarize ABATE Witness Dauphinais' and CEO Witness**
6 **Hotaling's recommendation?**

7 A40. Yes. Witness Dauphinais and Witness Hotaling put forth similar recommendations
8 that both the ZRC product and the R12 DR agreement should be extended beyond
9 May 31, 2033. Witness Dauphinais specifies that the extension should be applicable
10 "to the extent DTE has been unable to bring 550 MW of ZRCs of new capacity
11 online in MISO Zone 7 to replace the ZRCs provided by Google to DTE under the
12 CCAA and Rider 12 DR Agreement" (page 5). He argues that the sunseting of the
13 ZRC product and the R12 DR Agreement "is likely the principal contributor to
14 DTE's projected need for 677 MW of 'perfect capacity' in 2033. Since the 677 MW
15 of 'perfect capacity' is not associated with the CCAA or any agreement between
16 DTE and Google, it does not appear Section 2 of the PSA will provide any
17 protection for this situation for DTE's other customers" (page 26).

18
19 Witness Hotaling specifies that the availability of an extension "could be
20 conditioned upon whether the extension of these resources could address
21 incremental need identified as a result of the Customer in the next IRP" (page 15).
22 Her argument seems to be that if the ZRCs and/or DR are available beyond May
23 31, 2033, then the Commission should require their extension via this proceeding.

Line
No.

1 **Q41. Does the Company agree with ABATE Witness Dauphinais and CEO Witness**
2 **Hotaling's recommendation?**

3 A41. No. Both the ZRC transfer and the R12 DR agreement are Customer obligations
4 that the Customer has voluntarily agreed to as part of a broader negotiated
5 agreement captured through the special contracts. Requiring that the Customer (or
6 any customer) participate in DR would run counter to the voluntary nature of DR
7 programs. Requiring that the Customer provide ZRCs beyond what the Customer
8 has already agreed to is simply unreasonable.

9
10 As such, Witness Dauphinais and Witness Hotaling's recommendations rely on an
11 assumption that (1) the resources will be available beyond May 31, 2033, and (2)
12 the Customer is willing to provide these resources beyond May 31, 2033. Neither
13 of these assumptions has been assessed or verified, and therefore the
14 recommendation should not be considered in this case.

15

16 **Part VIII: ZRC product alternatives**

17 **Q42. What intervenor positions related to ZRC product alternatives are you**
18 **addressing?**

19 A42. I will address MEICEO Witness Sherman's recommendations to (1) offset the need
20 for 300 MW of ZRCs by expanding participation in the Smart Savers program, and
21 (2) establish a Virtual Power Plant ("VPP") program.

22

23 **Q43. Can you summarize MEICEO Witness Sherman's recommendations related**
24 **to ZRC product alternatives?**

Line
No.

1 A43. Yes. Witness Sherman first recommends that the Company expand enrollment in
2 its Smart Savers program by 100 MW to partially offset the 300 MW of ZRCs that
3 the Customer has agreed to transfer to the Company (page 41). She suggests this
4 expanded enrollment could be achieved through, for example, an additional
5 enrollment pathway where manufacturers of smart thermostats enroll and dispatch
6 participating devices in the Company's service territory. Witness Sherman also
7 suggests the Customer could subsidize the costs to residential ratepayers for a new
8 smart thermostat to support increased enrollment.

9
10 Witness Sherman goes on to recommend that the Company establish a VPP
11 program to "provide some portion of the needed 300 ZRCs" (page 32). She
12 additionally suggests enrollment pathways (e.g., up-front incentives, etc.) and
13 implementation timelines.

14

15 **Q44. Does the Company agree with MEICEO Witness Sherman's**
16 **recommendations?**

17 A44. No. Witness Sherman's recommendations seem to reflect a fundamental
18 misunderstanding of the ZRC product governed by the CCAA. Under the CCAA,
19 the Customer is providing ZRCs to the Company between June 1, 2028, and May
20 31, 2033 at no cost. The Company is not involved in the Customer's procurement
21 of ZRCs that will be transferred to the Company as part of the CCAA. Under the
22 CCAA, it is the Customer's obligation to provide the ZRCs and the source of those
23 ZRCs is at their discretion. The Company is not party to the Customer's
24 procurement of those ZRCs and the source of the ZRCs is not at issue, so Witness

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No.

1 Sherman's recommendation to partially meet the ZRCs through utility programs
2 has no relevance in this case.

3

4 Section 2.4 of the PSA also provides protections for a situation in which the
5 Customer does not provide the ZRCs, including a potential reduction in their load
6 ramp. Changing the CCAA structure such that the Customer is only required to
7 provide 200 MWs (with the other 100 MW provided through Company programs)
8 could introduce reliability risk to the Company's other customers since the
9 Company could not invoke Section 2.4 if it, for example, failed to achieve the Smart
10 Saver enrollment targets recommended by Witness Sherman.

11

12 Finally, the Customer is providing the ZRCs at no cost to the Company. It would
13 be unreasonable to change such an arrangement to the extent that it introduces any
14 costs to the Company or its customers.

15

16 **Q45. Is this special contract proceeding the appropriate forum to require the**
17 **Company to procure different resource types, such as additional demand**
18 **response or VPP resources, as substitutes for the ZRC product negotiated in**
19 **the CCAA?**

20 A45. No. The Commission's review in this proceeding should be limited to whether the
21 PSA and CCAA negotiated between DTE Electric and the Customer are reasonable
22 and should be approved. It should not be used as a vehicle to mandate new
23 Company-administered resource programs or a different resource portfolio that was
24 not proposed by the Company and not negotiated with the Customer.

Line
No.

1 The role of future resources, such as increased demand response or VPPs, should
2 be considered in the Company's IRP. But those future planning questions do not
3 provide a basis to replace or reduce the Customer's negotiated obligation to provide
4 ZRCs under the CCAA in this special-contract proceeding.

5

6 **Q46. Does this conclude your rebuttal testimony?**

7 A46. Yes, it does.

1 JUDGE STALEY: And Mr. Wollenzien.

2 MR. WOLLENZIEN: Yes. Thank you, your
3 Honor.

4 CROSS-EXAMINATION

5 BY MR. WOLLENZIEN:

6 Q Good morning, Mr. Foley. Can you hear me O.K.?

7 A Yes, and good morning.

8 Q Fantastic. Thank you. So just a couple quick
9 housekeeping things here before we get rolling. I had
10 previewed in my email to counsel that we'd be focusing on
11 the termination payment terms (inaudible) --

12 COURT REPORTER: I'm sorry. Mr.
13 Wollenzien, slow down a little bit because sometimes I
14 don't even know what you're saying.

15 MR. WOLLENZIEN: O.K. Absolutely.

16 COURT REPORTER: Thank you.

17 Q (By Mr. Wollenzien): So I previewed for counsel that I
18 plan to focus on the termination payment terms of the two
19 exhibits, 16 and 18, today, and that will be most of what
20 I'm asking you about, but just as a heads up, I'll be
21 asking some background questions and potentially some
22 questions about other non-termination payment matters as
23 well. Also, I requested around 45 minutes for this, but
24 it's possible we might go shorter than longer, though I
25 don't expect it to go for longer than an hour; however,

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1 if you do need to ask for a break in that time, I'd
2 appreciate as a matter of courtesy if you could wait
3 until a line of questioning is concluded before you
4 request a break.

5 One of the pieces is as to
6 confidentiality, so I prepared my questions here around
7 information that has been publicly filed, we're producing
8 discovery without a confidential labeling, and I believe
9 we can talk about, you know, hopefully all of this
10 without even going into a confidential record, but if at
11 any point during my questions you think that providing an
12 answer or providing a full answer to a question would
13 require delving into confidential material, please let
14 counsel know and we can go off the record and discuss
15 that situation.

16 With all that, do you have access to the
17 SharePoint for this matter?

18 A I do.

19 Q Great. And can you go into the folder labeled AG in the
20 SharePoint.

21 A O.K.

22 Q And I'm having to just have you scroll through, I'll be
23 making references to different documents in there; if
24 it's helpful for me to share my screen at some point, we
25 can do that, but as for right now, I'll just let you kind

1 of match up with the points I'm describing in the
2 documents. So if you wouldn't mind opening first the
3 document labeled as your Revised Direct Testimony in that
4 folder.

5 A O.K.

6 Q Great. Just a little bit of background on your
7 experience here. So it looks like, if I'm getting the --
8 I'm going to just very briefly go through your background
9 here. It looks like you have Lockheed Martin, Booz Allen
10 Hamilton, Deloitte, McKinsey, and then in 2017 joining
11 DTE; is that all correct?

12 A Yes.

13 Q Great. And then it looks like you've a had a couple
14 different titles at DTE, first Manager of Corporate
15 Strategy, then in 2020, Director of Regulatory Affairs,
16 and then in 2024, Director of Electric Marketing; is that
17 all right?

18 A Yes.

19 Q O.K., great. And it looks like, looking at page 2 of
20 your testimony, there's a description of past MPSC case
21 numbers you've testified in, right?

22 A Yes.

23 Q And it's about five cases prior to 21990, if I'm
24 understanding that correctly?

25 A Yes, five prior to 21990, yes.

1 Q And in those cases, what was the general, to the extent
2 you can kind of speak generally or briefly describe, what
3 was the sort of subject matter of your testimony in those
4 cases?

5 A In general, prior to U-21990, I was testifying on various
6 rate design and cost of service issues in general,
7 although I'd have to go back and check on the specific
8 topics that were discussed in those cases.

9 Q Thank you. O.K. And so if we then go down to page 3 of
10 your testimony, the very next page, there is a section, a
11 Q&A -- or strike that -- there's a section starting at
12 line 1 of page 3 described as Purpose of Testimony; are
13 you seeing that?

14 A Yes.

15 Q And then the initial Q&A on that page really describes
16 there the Company seeking approval of two special
17 contracts and other relief; am I reading that generally
18 correctly?

19 A Yes.

20 Q And so is it correct to say that the intended purpose of
21 your testimony is to provide an explanation of how the
22 Company intends these contracts to operate?

23 A In general, yes, although it's not the purpose of my
24 testimony to describe every term of the special contracts
25 or the related agreements but to discuss the overall

1 operation of the contracts and some of the key terms.

2 Q O.K. So that -- and that includes how DTE intends those
3 terms to operate; am I understanding that correctly?

4 A For the terms I discussed in my testimony, yes, that's
5 correct.

6 Q O.K. And so you mentioned a minute ago your current
7 title at DTE is Director of Electric Marketing; is that
8 right?

9 A Yes, it is.

10 Q So how does your role as the Director of Electric
11 Marketing come to bear on explaining the terms of these
12 agreements included within your testimony?

13 A Yeah, prior to my role as Director of Electric Marketing,
14 I spent roughly four years as a Director of Regulatory
15 Affairs where I led our cost of service and rate design
16 teams and became generally familiar with the regulatory
17 construct and processes here in Michigan. Given that
18 experience, I was brought on to the data center team here
19 at DTE that was pursuing such opportunities to bring that
20 Regulatory Affairs' experience to help develop these
21 contracts.

22 Q So you're saying it's your background in Regulatory
23 Affairs and then I guess the subset of substance within
24 that context that you're bringing to bear to I guess
25 describe and explain key contract terms here?

1 A In general, yes, my time in Regulatory Affairs was most
2 applicable to my ability to explain the key contract
3 terms here.

4 Q And were you involved in the development of the contract
5 terms here?

6 A I helped assess and developed some key terms of the
7 contracts, but I was not responsible for the drafting of
8 the contracts.

9 Q And were there any terms in particular that you were
10 involved in developing?

11 A I didn't prepare a catalog of all the terms I helped
12 develop or assess, but yes, there were some specific
13 terms; for example, the affordability backstop, what we
14 refer to as the affordability backstop, which is PSA
15 Section 5.1.3, for example.

16 Q O.K. Thank you. O.K. Well, let's go down to page 3 of
17 your testimony. I guess we're maybe already there. O.K.
18 On line 17 of page 3, you testify that, "The
19 September 10th date will satisfy the conditions precedent
20 set forth in the Contracts which require Commission
21 approval by September 10, 2026." Are you seeing that?

22 A Yes.

23 Q O.K. Now, you also sponsor as part of your testimony
24 Exhibit A-16 showing what's referred to as the Primary
25 Supply Agreement; is that right?

1 A Yes.

2 Q O.K. And a revised version of that exhibit has been
3 filed in the record, right?

4 A Yes.

5 Q O.K. And you're welcome to turn over to this document in
6 the SharePoint, or I can just reference it; if you know
7 the answers, you can just respond, whichever is easier
8 for you. So looking at that Exhibit 16, Exhibit A-16 I
9 should say, within that proposed contract, on paragraph
10 4.1, the proposed contract includes a description of
11 so-called conditions precedent, right?

12 A Yes.

13 Q O.K. And then in Section 4.2, there is a section of this
14 proposed contract that sets out what are called
15 conditions precedent deadlines; is that right?

16 A Yes.

17 Q And then in this proposed contract, the date on which all
18 the conditions precedent are satisfied is referred to as
19 the "effective date"; is that correct?

20 A Yes.

21 Q O.K. And is it correct then to say that going back to
22 your testimony on page 3, line 17, that the conditions
23 precedent terminology used there is referring to the same
24 conditions precedent as set forth in paragraph 4.1 of the
25 Exhibit A-16 proposed contract?

1 A Yes.

2 Q O.K. And so let's say if the contracts were approved by
3 the MPSC by the September 10 date you've included in your
4 testimony, the Exhibit A-16 contract still lists a
5 subsequent condition precedent deadline of September 24,
6 2026; isn't that correct?

7 A Can you clarify what section of the PSA lists
8 September 24, 2026?

9 Q Absolutely. So I'm looking at paragraph 4.2.4 which
10 relates to the condition precedent in Section 4.1.5. Are
11 you seeing that?

12 A I am.

13 Q O.K. And that's for a provision of a so-called customer
14 credit support; am I understanding that correctly?

15 A Yes, Section 4.1.5 of the PSA refers to customer credit
16 support.

17 Q O.K. So then is it fair to say that if those two
18 deadlines were to be met, the September 10 deadline for
19 MPSC approval and the September 24 deadline for customer
20 credit support, that you would expect that all the
21 conditions precedent would be satisfied sometime, say,
22 before the end of 2026?

23 MS. HAYDEN: Your Honor, I'm going to
24 place an objection to the extent the question is calling
25 for a legal interpretation of the contract. The dates in
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1 the contract speak for themselves.

2 MR. WOLLENZIEN: That's fine, I'll
3 reframe my question.

4 Q (By Mr. Wollenzien): Do you expect that the effective
5 date of this contract would be sometime before the end of
6 2026 if these deadlines are met, Witness Foley?

7 A So I wasn't involved in the drafting of the conditions
8 precedent or the definition of the effective date. I
9 think to this point I've just been confirming what you
10 read in this section, so I'm not a lawyer and I'm not
11 going to be bold providing what seems to be a legal
12 interpretation that you're asking for.

13 Q Do you have any idea of when the effective date might be?

14 A It's my understanding that the effective date is defined
15 through these sections that we've been discussing so far,
16 and that they would define when the effective date is.

17 Q Does the -- strike that. One second, Mr. Foley.

18 Thank you for your patience. There's one
19 other condition -- and moving on in just a second here; I
20 might come back. But there's one other condition
21 precedent here that I don't believe has a proposed
22 deadline in the conditions precedent deadline, and that
23 is 4.1.6. Are you seeing paragraph 4.1.6 here on page 5
24 of Exhibit A-16, Mr. Foley?

25 A Yes.

1 Q And am I correct in saying that there is not a condition
2 precedent deadline for that event in this paragraph 4.2,
3 or Section 4.2, I should say?

4 A I do not see a condition precedent deadline related to
5 4.1.6, no.

6 MS. HAYDEN: I think I would just like to
7 place another objection here, your Honor. There is
8 actually a deadline, 4.2.2, and again, I think the
9 contract speaks for itself.

10 MR. WOLLENZIEN: Thank you for that
11 clarification, counsel.

12 Q (By Mr. Wollenzien): O.K. Thank you. One second. O.K.
13 Thank you for your patience, Mr. Foley.

14 Insofar as the effective date is not
15 listed as a date certain per se here, or explicitly at
16 least, would you expect DTE to be commencing investments
17 to connect the customer prior to the effective date?

18 A I'm not responsible for the planning or execution of our
19 investments related to connecting to customers, so I'm
20 not the best person to respond to that.

21 Q Who would be?

22 A I believe Steven Benyard is leading those activities.

23 Q Would you expect ITC to be commencing investments --

24 A I have --

25 (Multiple speakers.)

1 COURT REPORTER: I'm sorry. Would you
2 expect?

3 Q (By Mr. Wollenzien): ITC, I can't recall the exact
4 breakdown of the acronym, but I believe probably,
5 Witness Foley, you know what I'm talking about here?

6 A I do. And likewise, I'm not responsible for the planning
7 or execution of ITC's construction activities and,
8 therefore, I'm not the best person to answer that.

9 Q O.K. Thanks for that information. Would that be Witness
10 Benyard as well who would have that information?

11 A I don't believe anyone at DTE is responsible for ITC's
12 planning or construction, but it's possible that Steven
13 Benyard has some knowledge that I don't have.

14 Q So I'm assuming you're not aware as well of any proposed
15 timeline by ITC, that would be a question for Witness
16 Benyard; am I understanding that correctly?

17 A That's correct, I don't have any knowledge of ITC's
18 planning for construction activities related to the
19 customer.

20 Q O.K. Let's go back to your testimony down to page 9.

21 A O.K.

22 Q O.K. And you have a question and answer here on line 8,
23 and the question is, "What is the planned Customer load
24 at the facility and when will the load materialize?" Are
25 you seeing that?

1 A I am.

2 Q And then you go on to testify starting at line 10 that,
3 "The maximum load of the facility is 1,000 megawatts
4 ('max load' or 'contract capacity'). The Customer's load
5 is planned to begin materializing in December 2027, with
6 max load being achieved by December 2028 ('load ramp' or
7 'load ramp period') and held constant thereafter." Are
8 you seeing those lines from your testimony there?

9 A I am, but it's important to note the following sentence
10 which points out that the customer can delay that ramp by
11 up to 18 months in the aggregate at their discretion.

12 Q Thank you. And I'll ask you more about that later, I
13 appreciate you pointing that out.

14 A O.K.

15 Q And then if we go to Exhibit A-16 at page 29.

16 A O.K.

17 Q This proposed contract defines commencement date as the
18 date on which the Customer first receives electric
19 service at the facility, right?

20 A Yes.

21 Q O.K. Let's go back for one minute to this paragraph 4.1
22 in the contract here, in the proposed contract here. And
23 I think even if you're not prepared to speculate about
24 the exact timing of an effective date, I just want to
25 confirm the dates that are in here, in this -- and I

1 should say it's in paragraph 4.2 here. So once again,
2 4.2 sets forth what are described as conditions precedent
3 deadlines, right?

4 A Yes.

5 Q And am I correct in seeing that all of the deadlines, at
6 least ostensibly included here, are in 2026?

7 A Yes, that's right.

8 Q O.K. Thank you. Let's now turn to the document in the
9 SharePoint that has been pre-labeled as Exhibit AG-8, if
10 you wouldn't mind.

11 A O.K.

12 Q O.K. And so the first part of this, the first 12 pages,
13 include discovery responses starting AGDE-3.73a and going
14 through AGDE-3.78 that comprise the Company's discovery
15 responses to the AG's third set of requests, all for
16 which you were listed as responding witness. Just going
17 through these first 12 pages here, do you recognize these
18 as your responses, as your same discovery responses as
19 you sponsored?

20 A Yes, they appear to be so.

21 Q O.K., thank you. And then the second part of this
22 document from page 13 to the end also include discovery
23 responses that you sponsored, these being from the
24 Company's responses to the AG's fifth set of discovery
25 requests. Happy to walk through each individual number

1 if that would be helpful, but would ask if you could
2 review these and just confirm if you would that they are
3 the same discovery responses that you sponsored?

4 A They appear to be so, although I haven't checked word for
5 word that they're exactly what we submitted, but I
6 believe they are.

7 Q Thank you.

8 MR. WOLLENZIEN: At this time, I'd like
9 to move for admission of this document as Exhibit AG-8.

10 JUDGE STALEY: All right. Are there any
11 objections to the admission of Exhibit AG-8?

12 Hearing none, Exhibit AG-8 is admitted
13 into the record.

14 Q (By Mr. Wollenzien): All right. Mr. Foley, if you
15 wouldn't mind turning to page 16 of this document labeled
16 proposed Exhibit AG-8.

17 A O.K.

18 Q And so on pages 16 and 17 here, these include the
19 Company's discovery responses labeled AGDE-5.83c and
20 AGDE-5.83d; are you seeing that?

21 A I am.

22 Q And the AG's questions here refer to Section 7.3 of
23 what's described as the Primary Supply Agreement,
24 correct?

25 A Yes.

1 Q O.K. And Section 7.3 of what's referred to as the
2 Primary Supply Agreement concerns the so-called
3 termination payment terms for this proposed contract,
4 correct?

5 A Correct.

6 Q O.K. And so in the AG's discovery requests, or discovery
7 questions 83c and 83d, the AG asked you for the maximum
8 number of months that could be used to calculate the
9 termination payment under a couple subparagraphs in that
10 Section 7.3, right?

11 A Yes.

12 Q And those, just to be clear, those two paragraphs or
13 subparagraphs, those are paragraphs 7.3(1) and 7.3(2),
14 right?

15 A Yes.

16 Q O.K. And in both of the discovery answers listed on
17 pages 16 and 17, you identified a period of 192 months as
18 the maximum number of months that could be used to
19 calculate the termination payment, right?

20 A Yes.

21 Q And in both answers, I believe you use the description,
22 although I think it's a partial quotable longer sentence
23 in one instance, but if you use the description both that
24 192-months' duration is "12-month" ramp period plus 15
25 years post load Ramp Completion Date"; am I seeing that

1 correctly?

2 A Yes.

3 Q O.K. So just to kind of refresh for a second here on
4 your testimony we just looked at a minute ago, page 9 of
5 your testimony, in there you say there's an expectation
6 of -- again, subject to your stipulation about a
7 potential delay in load ramp -- you present a projected
8 time for max load being achieved by December 2028, right?

9 A Yes, that's what I reference in my revised direct
10 testimony.

11 Q O.K. So we can fairly refer to that as being about the
12 timeline for the proposed load ramp completion date; am I
13 understanding that correctly?

14 A Because the Customer can delay their ramp by up to 18
15 months in the aggregate, the load ramp completion date
16 could occur at any point between December 2028 and 18
17 months after that.

18 Q O.K. But if they were to not delay, we can fairly
19 consider, based on your testimony here, that the
20 projected load ramp completion date would be sometime
21 around December 2028; am I understanding that correctly?

22 A Yes, sir.

23 Q So then in your discovery responses here to AG questions
24 83c and 83d, you also described a 12-month ramp, right?

25 A Yes.

1 Q O.K. So am I reading this, your responses here correctly
2 as indicating that the earliest starting point for
3 calculating a termination payment under paragraph 7.3(1)
4 and 7.3(2) of the proposed PSA as being in December 2027?

5 A The intent of that response is if the PSA were terminated
6 pursuant to the referenced sections prior to the
7 commencement date, the termination payment would be
8 calculated based on 192 months of minimum monthly
9 charges, which include 12 months of ramp-up period plus
10 15 years of post program completion date.

11 Q But if you -- O.K. And let's go back to your -- let's,
12 can we go back to your testimony again here in the same
13 section, you said load is planned to begin materializing
14 in December 2027, right?

15 A Yes.

16 Q So, and if the commencement date is the date that the
17 customer begins taking service, is it fair to also say
18 that the commencement date is expected to be somewhere
19 right around the time of December 2027?

20 A Yes.

21 Q O.K. But as you looked at a minute ago, all of the
22 deadlines condition precedent, they're in 2026, right?

23 A Yes.

24 Q So if this agreement was terminated prior to the
25 commencement date, let's say in mid 2027, wouldn't the

1 maximum number of months for calculating the termination
2 payment be longer than 192 months?

3 A I don't think so, but if you can clarify why you think it
4 would be more than 192 months, I may be able to respond.

5 Q Right. So if we're saying that there is 15-year post
6 load ramp completion date component and, without a delay,
7 that's expected to occur in December of 2028, and there's
8 a 12, what you describe as a 12-month ramp, which, as you
9 describe, would be expected to start in 2027, there
10 appear to be a period of time between the conclusion of
11 all these conditions precedent deadlines, let's say late
12 2026, and the commencement date of December 2027. Am I
13 misunderstanding that?

14 A No. But during that interim period between the effective
15 date and the commencement date, the Customer is not
16 subject to minimum monthly charges because they have not
17 committed to any load through the PSA.

18 Q Is the Customer subject to a termination payment during
19 that window?

20 A Yes.

21 Q So how is that calculated; are you saying that's just
22 calculated -- that would only be calculated starting with
23 the December 2027 date?

24 A Yes, because that's when the Company has committed to
25 serve their load and they've committed to begin paying

1 minimum monthly charges, assuming they don't exercise
2 their 18-month delay, up to 18-month delay.

3 Q O.K. So just to be clear on this, be clear in a couple
4 ways on it, you're saying that between the effective date
5 and the commencement date, there would be an applicable
6 termination payment, but the maximum calculation would
7 use as the first possible starting date the commencement
8 date; am I understanding that right?

9 A Yes.

10 Q O.K. And so let's look back -- and I also just want to
11 be clear here on the contract language as well, so if you
12 wouldn't mind turning back over to Exhibit 16 at page 13,
13 paragraph 17.3 again.

14 A Can you say that section again?

15 Q Absolutely. Section 7.3 of the PSA, of the proposed
16 Primary Service Agreement.

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

18 Q O.K. So if we go down into each of these subparagraphs
19 (1) and (2), the language used there for calculating the
20 termination payment is "an amount equal to the sum of the
21 Minimum Monthly Charge for each month between the Early
22 Termination Date and the fifteenth anniversary of the
23 Load Ramp Completion Date", right?

24 A Yes.

25 Q O.K. And so I guess what you're saying here is that

1 because -- I guess for your testimony here, the minimum
2 monthly charge would not kick in until the commencement
3 date, that the calculation here would only start with the
4 commencement date as the first kind of timeline point for
5 the termination payment calculation; am I understanding
6 that correctly?

7 A I believe technically it begins on December 2027. We do
8 note in my testimony that the Customer may take some
9 amount of service prior to that due to the power needs of
10 their construction activities, but the first month that
11 the Customer is subject to a minimum monthly charge,
12 assuming they don't delay their load ramp, would be
13 December 2027.

14 Q O.K. One second, thank you.

15 So let's just kind of look at it in a
16 hypothetical here just to make sure I'm understanding the
17 operation. So let's say if the effective date occurs at
18 the end of 2026, and then in June of 2027, there is some
19 Customer there (inaudible) --

20 COURT REPORTER: I'm sorry. ...there is
21 some Customer?

22 MR. WOLLENZIEN: Sorry, sorry, Ms. Penn.

23 Q (By Mr. Wollenzien): ... some Customer event of default
24 that triggers an early termination, would -- assuming no
25 load ramp delay, is it a correct to say that the

1 Company's presumed calculation would use December 2027 as
2 the start date for figuring out the termination payment?

3 A Yes.

4 Q O.K. And just looking just one more second at the terms
5 here -- and I know there was some amendment here as well,
6 we'll talk about that in a second -- but if we're looking
7 at these same set of terms in Section 7.3 of the proposed
8 PSA, paragraph 7.3(1) here as described, it's intended to
9 apply in the event of an early termination other than due
10 to a Company event of default or Customer event of
11 default; am I reading that correctly?

12 A Yes.

13 Q O.K. And then 7.3(2) and 7.3(3), if I'm reading these
14 right, are intended to apply in the event of an early
15 termination due to a Customer event of default; am I
16 reading that correctly?

17 A Yes.

18 Q And then under the entirety of this Section 7.3, it looks
19 like the length of the contract does not provide for
20 applicability of a termination payment in the event of a
21 so-called Company event of default; am I reading that
22 correctly?

23 A Yes, that's my understanding.

24 Q O.K. There were some amendments to this section in your
25 rebuttal testimony, right?

1 A There was in Exhibit A-22.

2 Q Yeah, I apologize, I meant to ask that before. You
3 sponsored an exhibit that demonstrated an amendment to
4 this section, right?

5 A Yes.

6 Q What was that amendment exactly?

7 A So I'd have to bring it up and review it, but essentially
8 in Section 7.3, Part 2 and Part 3, those sections refer
9 to an anniversary of the commencement date, and the
10 amendment changed that to an anniversary of the load ramp
11 completion date.

12 Q O.K. If it would be helpful, I can -- well, let me look
13 at it for one second because I have it here. Yeah, I'll
14 just upload to the SharePoint real quick, it will take me
15 just a minute.

16 A I have a printed copy here, too. I'm referring to No. 2
17 of the Exhibit A-22.

18 Q O.K., that is helpful. And so just to be clear on what
19 exactly it changes, it is, in paragraph 7.3(2) and (3),
20 on the first line in each of those paragraphs, there's a
21 description, anniversary of the commencement date, and
22 those are the two specific pieces of those paragraphs
23 that are being changed; am I understanding that
24 correctly?

25 A Yes.

1 Q O.K. Thank you. On one other point on this, if you
2 don't mind going back to those same discovery responses
3 we were just looking at on page 16 of what's now labeled
4 as proposed Exhibit AG-8, you have in the last line of
5 this answer in the parenthetical here, it says, "12-month
6 ramp period plus 15 years post Load Ramp Completion Date
7 if the termination occurs prior to the Commencement
8 Date." I'm assuming this language here, "if the
9 termination occurs prior to the Commencement Date" --
10 well, let me ask you this. Strike that.

11 Is there any significance to the
12 inclusion of this language here, if the termination
13 occurs prior to the Commencement Date, as included in
14 your answer to AG Question 83c?

15 A I was just trying to clarify how we did the math to 192
16 months that says, as we talked about earlier, if the
17 contract were to be terminated prior to the Customer
18 taking service, which by definition would be before the
19 commencement date, it would be using 192 months to
20 calculate the termination payment.

21 Q Thank you. Thank you. O.K, all right. Let us kind of
22 change gears a little bit here and go back to your
23 revised testimony as included in the SharePoint and go to
24 page 15, and this gets into the load ramp flexibility
25 point you were mentioning a minute ago.

1 A I'm looking at a printed copy of my revised direct
2 testimony, but I'm at that page.

3 Q Great. Thank you. So the starting line 21, you have a
4 section here on what's described as Customer load ramp
5 flexibility, right?

6 A I do.

7 Q And you say on page -- I'm sorry -- on line 1 of page 16,
8 that the Customer can "temporarily delay their load ramp
9 or any increase in the scheduled ramp up to 18 months in
10 the aggregate," right?

11 A Yes.

12 Q So could a load ramp delay result in a delay of the
13 commencement date?

14 A I think those two would probably be related, I'm not
15 sure. I think you asked if one could be caused by the
16 other, and I'm not quite sure what you mean by caused by.

17 Q I think I used the word result, could a load ramp delay
18 result in the delay of the commencement date. In other
19 words, is one of the effects of this -- and maybe this is
20 obvious, but I just wanted to be clear. Is one of the
21 effects of this that if the Company were to use part of
22 that -- I'm sorry, strike that -- if the Customer were to
23 use part of that 18-month aggregate to say we want to
24 start materializing load later than 2027, is that a
25 possible outcome of the load ramp flexibility terms you

1 propose here?

2 A Yes.

3 Q O.K. Would such a delay serve to change your answer of
4 192 months for the maximum duration that could be used to
5 calculate a termination payment under Section 7.3(1) and
6 7.3(2) of the proposed PSA?

7 A So I haven't assessed that specific situation, but I
8 could imagine if the Customer were to exercise a delay
9 and then the PSA would be terminated at that same time,
10 we would be using the new delayed load ramp to calculate
11 the termination payment, and that could affect the
12 calculation of that payment, but again, the specifics of
13 that situation, we haven't assessed.

14 Q Well, actually, let me ask you this. If -- I guess even
15 a more specific way or simpler way here, if -- let's say
16 the commencement date were delayed by the result of a
17 delay in the load ramp, would that impact in any way the
18 applicability of the termination payments in the event of
19 an early termination between the time of the effective
20 date and the time of the commencement date?

21 A No. The termination payment would still be calculated
22 based on the remaining minimum monthly charges between
23 the termination date and the 15th anniversary of the
24 load ramp completion date.

25 Q In other words -- so just to be clear, you're saying it

1 would not impact the applicability of the termination
2 payment obligation during that window between the
3 effective date and the commencement date?

4 A Correct.

5 Q Thank you. One second.

6 Would a delay in the load ramp -- strike
7 that.

8 Could a delay in the load ramp impact the
9 duration of this time period included in paragraph 7.3(1)
10 and (2) of the proposed PSA as to the 15th anniversary
11 of the load ramp completion date?

12 A No, because those sections again are related to the
13 anniversary of the load ramp completion date, and that
14 load ramp completion date could shift out because of a
15 Customer-exercised delay, but in any case, it would still
16 be, the termination payment would still be calculated
17 based on 15 years after that load ramp completion date.

18 Q Thank you. O.K. Let's go back -- and I'm getting
19 through most of my questions, at this point just giving
20 you a heads up; so one other section here, then I'll
21 probably pause for just a brief break to make sure I
22 don't have any, you know, stuff that I didn't get around
23 to to follow up on, but just giving you a heads up here.
24 And also, I'm not quite exactly --

25 JUDGE STALEY: Mr. Wollenzien.

1 MR. WOLLENZIEN: Go ahead.

2 JUDGE STALEY: We are coming up on an
3 hour and Ms. Penn will need a break, too, so what kind of
4 timeframe are you looking at here?

5 MR. WOLLENZIEN: I would ask for maybe
6 another, O.K., I don't know if it will even be ten
7 minutes. This actually might be a good time to take a
8 brief break and that could give me a chance to kind of
9 get my followups figured out now and I could just go
10 straight through another 15 minutes maybe. And I
11 apologize, too, I kind of lost track time of given the
12 period at the beginning of this going over the other
13 administrative matters, so. O.K. All right, if you
14 wouldn't mind just taking like a short break now and then
15 I can get everything lined up to just wrap up in the next
16 section.

17 JUDGE STALEY: That sounds good. Will
18 that work for you, Ms. Penn?

19 COURT REPORTER: Yes.

20 JUDGE STALEY: O.K. How long of a break
21 would you like to take, Ms. Penn?

22 COURT REPORTER: Whatever's good for you.

23 JUDGE STALEY: About, 10, 15 minutes?

24 COURT REPORTER: Yes.

25 JUDGE STALEY: O.K. Let's just do a
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1 ten-minute break.

2 MR. KESKEY: Your Honor, can I find out a
3 time when I can bind in the testimony of the GLREA
4 witness?

5 JUDGE STALEY: Yes. And for the record,
6 this is Mr. Keskey, so he has returned from his other
7 prehearing this morning. Let's go off the record, let's
8 take that ten-minute break, and can we come back on and
9 talk about that, Mr. Keskey?

10 MR. KESKEY: That's fine, that's fine,
11 sure.

12 JUDGE STALEY: All right. So let's
13 return at about 10:17 or so.

14 MR. KESKEY: O.K.

15 JUDGE STALEY: Thank you. We're off the
16 record.

17 (Recess from 10:07 a.m. until 10:18 a.m.)

18 JUDGE STALEY: We are back on the record
19 in Case No. U-22058, and I will return this to
20 Mr. Wollenzien for your cross-examination of Mr. Foley.

21 MR. WOLLENZIEN: Thank you, your Honor.
22 Actually, could we go off the record for just one second?

23 JUDGE STALEY: Yes. We're off the
24 record.

25 (At 10:18 a.m., brief discussion.)

1 JUDGE STALEY: All right. We're back on
2 the record.

3 MR. WOLLENZIEN: Thanks everyone, thank
4 you for your patience. And I know this is taking a
5 little bit longer than I expected, but I am nearing the
6 end of my questions, so once again, thank you.

7 Q (By Mr. Wollenzien): Witness Foley, if you wouldn't mind
8 going back to Exhibit AG-8 as included in the SharePoint
9 at page 1.

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

11 Q O.K. So in this question, this discovery question, the
12 AG asked about termination payment terms under the
13 contract referred to as the Clean Capacity Accelerator
14 Agreement included in the Company Exhibit A-18, correct?

15 A Yes.

16 JUDGE STALEY: Mr. Wollenzien, may I
17 interrupt a moment?

18 MR. WOLLENZIEN: Yes.

19 JUDGE STALEY: I forgot that I was going
20 to address Mr. Keskey's request for information regarding
21 bind in. Can we go off the record real quick just to
22 address that?

23 MR. WOLLENZIEN: Absolutely, your Honor.

24 JUDGE STALEY: My apologies. Mr. Keskey,
25 are you here? You're on mute, if you can hear me,

1 Mr. Keskey.

2 MR. KESKEY: Yeah, I'm just back.

3 JUDGE STALEY: O.K. We're off the
4 record.

5 (At 10:20 a.m., off-record discussion.)

6 JUDGE STALEY: All right. We're back on
7 the record. And my apologies, Mr. Wollenzien. You can
8 continue.

9 MR. WOLLENZIEN: Thank you, your Honor.
10 You're totally fine, appreciate that courtesy.

11 Q (By Mr. Wollenzien): O.K. Witness Foley, we were just
12 discussing this Exhibit 8, page 1. Do you recall that?

13 A Yes.

14 Q O.K. And so in your response here, you reference a
15 number of paragraphs from the proposed contract included
16 in Exhibits A-18, right?

17 A Yes.

18 Q O.K. And there's a long paragraph here, if you wouldn't
19 mind reading it, probably the easiest way to do this, if
20 you wouldn't mind reading from the start of the paragraph
21 that says, "Importantly", and it goes across that page
22 and then down to ending with "termination payment
23 calculation", or you can go to the end of the paragraph,
24 that's fine, too.

25 A I'm sorry, you just wanted me to read my response here,
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1 just read you my response?

2 Q Yeah. I can read it if you'd like. I just wanted to
3 kind of have the language of your response, and then we
4 can talk about a couple of pieces of that. How about
5 this, I'll just -- I can read it very briefly here. So
6 just confirming this is in your response here, starting
7 on page 1, going into page 2, you said in response,
8 "Importantly, as governed by CCAA Section 3.1.6 for clean
9 capacity projects and Section 4.1.4 for renewable energy
10 projects, the Company shall update the respective
11 portfolio matrix at least thirty calendar days prior to
12 the Commercial Operation Date (COD) of each project to
13 include an estimated project revenue requirement and
14 associated billing period charges. Said differently, the
15 Company can update the respective portfolio matrix and
16 provide an estimated project revenue requirement at any
17 time between a project being entered into its respective
18 portfolio and 30 days prior to the project achieving COD.
19 If the Customer were to default under CCAA Section 9, and
20 any project had been entered into its respective
21 portfolio matrix but a revenue requirement had not yet
22 been estimated, the Company then would provide an updated
23 portfolio matrix with an estimated revenue requirement
24 for any such project. The updated portfolio matrix would
25 then form the basis for the termination payment

1 calculation." Are you seeing that section of your
2 response?

3 A I am. I am.

4 Q O.K. So just a couple questions about the mechanics of
5 the process you described here. Is the updating of the
6 project portfolio matrix something that must occur prior
7 to or at the same time as providing a revenue requirement
8 for a project in the matrix?

9 A Sorry, can ask you that one more time?

10 Q Yeah. I'll reframe this, and we can ask it either way.
11 Could the Company include a revenue requirement for a
12 project in its respective matrix if the project itself
13 was not included in the matrix?

14 A I'm sorry, just one more time. Are you asking if --

15 Q Yeah.

16 A -- the Company can include a revenue requirement for a
17 project that is not included in the respective portfolio
18 matrix?

19 Q Yes, that's the question.

20 A No, it cannot.

21 Q O.K. And another maybe somewhat complicated question, so
22 bear with me, and I can reframe it if that would be
23 helpful in any way, if that would be understandable, if
24 understandable I should say. Just sort of joking there.
25 Is inclusion of a revenue requirement in a project

1 matrix, estimated or otherwise, something that must occur
2 prior to or at the same time as the Customer paying a
3 termination payment?

4 MS. HAYDEN: Your Honor, I'm going to
5 place an objection to the extent the question is looking
6 for a legal analysis of this term. I think the paragraph
7 that, before the one that Mr. Wollenzien read describes
8 how this process plans out, there's more context
9 (inaudible) --

10 COURT REPORTER: I'm sorry. Ms. Hayden,
11 I'm getting some fuzz in there so I'm not getting what
12 you said. Just repeat your last sentence.

13 MS. HAYDEN: Sure. There's more context
14 in the paragraph above the one that Mr. Wollenzien read
15 into the record.

16 JUDGE STALEY: Mr. Wollenzien, your
17 response.

18 MR. WOLLENZIEN: I mean I'm a little
19 bit -- I mean I'm asking for clarification on how these
20 terms are supposed to function and how the termination
21 payment is supposed to function. My understanding is
22 that is part of Witness Foley's, you know, purpose, if
23 not central purpose in this case, and it's actually a
24 question that we asked in discovery and did not get a
25 direct response on. It's Question 3.73. It really just

1 referred, just said, the answer: See response to 3.73a,
2 which was what I just read from, so I'm just trying to
3 get a clear answer on the question we asked in discovery.

4 JUDGE STALEY: All right.

5 MR. WOLLENZIEN: I can think for another
6 minute about how this might implicate a legal conclusion,
7 but my understanding, there is a, based on the other
8 responses we got here, it's sort of order of operations
9 or a process by which things have to take place, and I
10 just want to make sure that I'm understanding that
11 correctly and understand how the Company intends this
12 Agreement to operate if it's accepted or approved by the
13 Commission.

14 JUDGE STALEY: O.K. Mr. Foley, you can
15 speak to, you know, the process if you're aware, you
16 know, of that piece of the question that Mr. Wollenzien
17 has asked, and you're not expected to give any sort of
18 legal analysis or legal conclusion, but if you could
19 answer his question by way of the process as he just
20 discussed, I will allow that.

21 A O.K. Could you repeat the question one more time?

22 Q (By Mr. Wollenzien): Yeah. And let me maybe reframe
23 this in a way that is less objectionable as well, maybe
24 we can help everybody out here.

25 Under the provisions of the proposed CCAA
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1 as it's described and the sort of mechanics of that as
2 you included in your discovery response AGDE-3.73a, is
3 the customer obligated -- you know what, strike that.
4 Give me one second to think about this.

5 O.K. Under the operation of the terms
6 included in the so-called CCAA as proposed in Exhibit
7 A-18 and your discovery response AGDE-3.73a, is the
8 inclusion of a revenue requirement in a project matrix,
9 estimated or otherwise, something that must occur prior
10 to or at the same time as the Customer paying a
11 termination payment; in other words, does the inclusion
12 of a revenue requirement have to happen before the
13 Customer makes a termination payment?

14 A The termination payment is based on the billing period
15 charges included in each project's respective portfolio.
16 Those billing period charges are calculated once a
17 revenue requirement is added to the portfolio matrix, and
18 therefore it would not be possible to calculate the
19 termination payment without the inclusion of a project's
20 revenue requirement that would then be added to its
21 prospective portfolio.

22 Q Thank you. O.K. Maybe just one other kind of like odds
23 and end question here and then I'll get to the piece that
24 goes into confidential, just give me one second to think
25 about this.

1 Did -- strike that.

2 Was the Company's -- to the extent that
3 you can answer this, is the Company's design for
4 termination payment calculation in the PSA intended to
5 encompass the potential cost of decommissioning assets
6 constructed to interconnect the Customer should the
7 Customer leave service?

8 A Construction of the termination payment under the PSA is
9 not tied to specific investments that the Company may or
10 may not make, instead the termination payment is based on
11 the minimum monthly charges that the Customer would owe
12 to the Company.

13 Q So let's move back to -- and I'm almost done here. I
14 wanted to be clear on one thing we talked about a couple
15 minutes ago, which is this period of time between on the
16 so-called effective date and so-called commencement date
17 under, and in the context of the proposed PSA termination
18 payment provision. So if you wouldn't mind kind of
19 switching back over here to the Company's Exhibit A-16,
20 Section 7.3.

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

22 Q O.K. So we had asked in discovery, the AG had asked in
23 discovery about these subparagraphs 7.3(1) and 7.3(2) and
24 the calculation for the termination payment therein, and
25 I just want to be clear, and maybe you've already

1 answered this and I'm just not quite remembering exactly,
2 but I just want to be very clear on this: For the period
3 of time between the effective date and the commencement
4 date, am I correct in understanding you testified earlier
5 that there would still be an applicable termination
6 payment, but the time period used to calculate that
7 termination payment would start with the expected
8 commencement date and conclude with the 15th anniversary
9 of the load ramp completion date?

10 A It would be expected to begin on December 2027, assuming
11 that the Customer doesn't exercise their right to delay
12 their load ramp, and would conclude at the 15th
13 anniversary of the load ramp completion date. You
14 specifically mentioned the commencement date, which can
15 technically be before December 2027 if, for example, the
16 Customer takes any amount of power for construction
17 purposes. But the minimum monthly charge that the
18 Customer is subject to begins on December 2027, assuming
19 they don't exercise their right to delay the load ramp.

20 Q But you're drawing a distinction between any time the
21 Customer begins taking service and the point at which
22 they begin making minimum monthly charges; am I hearing
23 that correct in your answer there?

24 A In clarifying, that termination payment is based on
25 minimum monthly charges, and the Customer is not subject

1 to a minimum monthly charge until December 2027, assuming
2 they don't exercise the right to delay their load ramp.

3 Q Okay. Well, let's take a couple scenarios. Let's just
4 say there's no expected delay and you take December 2027
5 as the starting point. In that context, is it correct to
6 say that you would still use the expected minimum monthly
7 charge at that point to calculate -- sorry -- to
8 calculate the termination payments? In other words,
9 there would still be a termination payment, just the date
10 would not -- the date for calculating it would not start
11 until December 2027; am I understanding that right?

12 A I'm not sure I understand your hypothetical, specifically
13 I'm not understanding when you're suggesting the
14 termination occurs.

15 Q O.K. So let's say termination occurs in June 2027 and
16 there's no reason to think there's going to be a delay in
17 when the minimum monthly charges start. So at that
18 point, you're saying that won't be -- let's back up for
19 one second. In general, you're saying that the minimum
20 monthly charges won't start until December 2027 or some
21 later date if there's a delay of the load ramp?

22 A Correct.

23 Q O.K. So in June 2027, or assuming that there's not going
24 to be any minimum monthly charges?

25 A Customer is not subject to minimum monthly charges in

1 June 2027.

2 Q O.K. So the thing that I want to confirm is that even
3 though the Customer is not subject to minimum monthly
4 charges in June 2027, that if there were to be an early
5 termination at that time, let's say by Customer event or
6 default, that you would still calculate an amount based
7 on the minimum monthly charge, you would just use as the
8 starting date for that calculation December 2027,
9 assuming no delay in the load ramp; am I understanding
10 that correctly?

11 A You are.

12 Q O.K. And I think we talked about this earlier as well,
13 but even if there were a delay in the start of the
14 minimum monthly charges, the calculation duration wise
15 would be the same?

16 A It would depend on when the termination date is. If
17 they're partially through their ramp-up period, we would
18 use the remaining portion of their ramp-up period plus 15
19 years post load ramp completion date to calculate the
20 termination payment.

21 Q Sorry, can you say that one more time? I think I kind of
22 missed something there.

23 A If the termination were to occur partially through the
24 ramp-up period, we would use the remaining months of the
25 ramp-up period plus 15 years post load ramp completion

1 date as the basis for the termination payment.

2 Q O.K. So there's a couple different scenarios here. I
3 don't mean to be taking up too much of your time, I'll
4 just make sure I'm understanding all these different
5 iterations.

6 So let's say a -- let's say the Customer
7 is part of the way through their load ramp, let's say we
8 clear December 2027, they're getting minimum monthly
9 charges, and then there's a delay, there's a signal for a
10 delay in the load ramp completion date, does that delay
11 period get included in the calculation, or is it like
12 tolled or not included in the calculation?

13 A They exercise their delay, that becomes the new load ramp
14 and that becomes the new basis of minimum monthly
15 charges, so that delayed load ramp is what we would use
16 in the calculation of the termination payment.

17 Q When you say it becomes the new load ramp, I just want to
18 make sure I'm understanding this. So ostensibly you have
19 projected with no delay a load ramp between December 2027
20 and, or, you know, let's just say from minimum monthly
21 charges starting December 2027 through to December 2028;
22 is that a fair characterization of what you put forth in
23 testimony here?

24 A That is the Customer-committed ramp, yes.

25 Q And so if they get, if the Customer gets in to a period

1 of a minimum monthly charges and they delay by six months
2 let's say, what do you mean that that becomes the new
3 load ramp, that the new load ramp starts over at that
4 point, at the end of that six-month delay or -- I just
5 don't understand like what, how the -- if things get
6 added or subtracted or if it stays the same and just gets
7 moved?

8 A During the ramp-up period, there is a defined capacity
9 that the Company has agreed to serve, and it's defined by
10 month, so if, for example, they began ramping, meaning
11 they began their ramp in December 2027 as established in
12 the PSA and then while they were ramping decided to
13 delay, what effectively would happen is any increase in
14 that ramp would be delayed and they would be held at
15 whatever level of service that was prevailing at the time
16 of their exercised delay, so essentially they were
17 delaying an increase in their load, which also then holds
18 the minimum monthly charge at that same amount while
19 their delay is being exercised.

20 Q So then if they are held in that, let's say they're into
21 this minimum monthly charge period, essentially just
22 starting in December 2027, and exercise a delay of six
23 months where they're held at whatever capacity milestone
24 I guess you might call it, do those initial months get
25 added to the termination payment calculation?

1 A Yes. At the time of termination, we will use the
2 remaining ramp period plus 15 years post ramp completion
3 date to calculate the termination payment, yes.

4 Q O.K. So I mean this was not kind of along the lines of
5 my question earlier, I understand that, it's not a
6 gotcha, but I guess theoretically if there were a delay
7 in this context we're describing, that could extend the
8 termination payment calculation or the duration that you
9 would use for longer than the 192 months?

10 A I'm not sure. I haven't assessed that specific situation
11 in which the Customer both exercises a delay and the PSA
12 is terminated.

13 Q O.K. Well, that -- O.K. And this is sort of aside from
14 what I wanted to ask you about anyway, but you discussed
15 the, kind of the changes that would occur in the context
16 of the delay, and I just want to make sure (inaudible) --

17 COURT REPORTER: ...in the context of
18 the --

19 (Multiple speakers.)

20 COURT REPORTER: You're getting faster
21 and faster. ...in the context of the delay?

22 MR. WOLLENZIEN: I'm sorry. I'm sorry,
23 Lori. Thank you. I will --

24 Q (By Mr. Wollenzien): I was saying that's sort of an
25 aside from the line of questioning that I have, but I

1 just wanted to make sure I was understanding what you
2 were saying, Witness Foley.

3 But going back here, so we talked about a
4 context where early termination might occur between
5 effective date and the beginning of minimum monthly
6 charges starting December 2027, and then I was intending
7 to ask about the situation where that sort of the, of the
8 monthly minimum charges is delayed until a later date.
9 And I guess my question is, in that context, say that's
10 all that happens, if the load ramp is otherwise as you
11 project, which has been pushed back let's say to
12 June 2028, is the calculation for the termination payment
13 effectively the same as it would be if --

14 A Yes. In that hypothetical -- under that hypothetical, if
15 they haven't begun being subject to minimum monthly
16 charges, then the calculation and the amount would be the
17 same.

18 MR. WOLLENZIEN: All right. With that, I
19 would like to transition over to the Confidential, or I
20 guess go off the record, if you don't mind, your Honor.

21 COURT REPORTER: You're muted, Judge.

22 JUDGE STALEY: My apologies. We're off
23 the record.

24 (Off-record discussion from 10:44 a.m. until
25 10:58 a.m.)

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1 (Transcript continues on Page 212 of the
2 Confidential Record.)

3 - - -

1 (Transcript continues following Page 223 of the
2 Confidential Record.)

3 - - -

4 JUDGE STALEY: We are back on the record,
5 the Public Record in Case No. U-22058. Mr. Wollenzien,
6 you've concluded your cross-examination of Mr. Foley?

7 MR. WOLLENZIEN: That is correct, your
8 Honor. Thank you.

9 JUDGE STALEY: All right. Thank you very
10 much. So we will move on to is it Ms. Li who has
11 cross-examination of Mr. Foley?

12 MS. LI: Yes, your Honor.

13 JUDGE STALEY: All right. Ms. Li, I will
14 turn this over to you.

15 MS. LI: Thank you, your Honor.

16 JUDGE STALEY: I can't see you for some
17 reason, where are you? Oh, there you are. O.K., go
18 ahead.

19 MS. LI: All right.

20 CROSS-EXAMINATION

21 BY MS. LI:

22 Q Good morning, Mr. Foley. Can you hear me all right?

23 A Good morning. I can.

24 Q My name is Helen Li, and I represent Sierra Club in this
25 proceeding. How are you doing today?

1 A Good.

2 Q Apart from being questioned a lot I guess. So I'd like
3 to talk with you about a few aspects of your testimony
4 and discovery responses. To give you a bit of a preview,
5 I have three buckets of topics; the Primary Supply
6 Agreement paragraphs 5.1.1 and 5.1.2, the affordability
7 backstop, which will take the bulk of our time, and a few
8 questions about the renewable energy buildout.

9 But just a few procedural points first.
10 I wanted to ensure that you have access to the hearing
11 exhibits that MEC, NRDC, and Sierra Club uploaded to the
12 SharePoint site.

13 A So I got kicked out after our last, but I'm trying to
14 re-login right now, and it looks like it's going to work,
15 so if you give me one minute, I'll be able to confirm
16 that.

17 Q Of course, take your time.

18 JUDGE STALEY: And Ms. Li, are those
19 identified as MNS?

20 MS. LI: Yes, there should be an MNS
21 folder and then there's a Hearing Exhibits folder within
22 that MNS folder, and then within that, there should be a
23 folder for Mr. Foley.

24 JUDGE STALEY: All right. Thank you.

25 MS. HAYDEN: Your Honor, having some
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1 technical difficulties here, so I'm able to get the
2 exhibits up so will share them with Mr. Foley.

3 Q (By Ms. Li): Great. So you're good to proceed,
4 Mr. Foley?

5 A I am.

6 Q O.K. And so just to make sure, do you see exhibits
7 within the folder that has your name in it in the MNS
8 folder?

9 A Yes.

10 Q Great. And second, you reviewed the direct testimony and
11 exhibits of MEC/NRDC/Sierra Club witness Dr. Bryndis
12 Woods; is that correct?

13 A I did around the time they were submitted, yes.

14 Q But you're generally familiar with the exhibits that
15 Dr. Woods sponsored?

16 A No, I'm not at the moment, I'd have to review them.

17 Q O.K. I will be referring to them, they are -- the ones I
18 refer to will be discovery responses that you sponsored,
19 so I think at that point you can tell me if you remember
20 them.

21 A Yes, that's fine.

22 Q O.K., great. And just third, I wanted to learn a bit
23 more about your role at DTE, so Mr. Wollenzien covered
24 this a bit as well. In December 2020, you became
25 Director of Regulatory Affairs. Can you briefly explain

1 your roles and responsibilities as Director of Regulatory
2 Affairs?

3 A Yes. As a Director of Regulatory Affairs, I led our cost
4 of service and rate design teams for the electric
5 utility, and those teams participated in a rate case and
6 generally do those cost of service and rate design
7 activities for the Company.

8 Q Do you have any connection with the regulation for
9 Renewable Portfolio Standards in Michigan?

10 A I'm familiar at a high level with those regulations, but
11 my team while I was in Regulatory Affairs was not
12 responsible for those regulations.

13 Q O.K. And in December 2024, you started as the Director
14 of Electric Marketing; is that correct?

15 A It is.

16 Q And can you briefly explain your roles and
17 responsibilities as Director of Electric Marketing?

18 A Sure. As Director of Electric Marketing, at a high
19 level, I lead three teams: One is related to electric
20 vehicles and how the Company supports the adoption and
21 acceleration of electric vehicles; I also have an
22 electric marketing team who generally designed and
23 executes our education outreach campaigns in consultation
24 with other Company groups; and lastly, I have a product
25 development team that explores and potentially launches

1 new projects for our customers.

2 Q Which one of those buckets would kind of cover the role
3 you have for the special contracts for the Customer here?

4 A My experience in Regulatory Affairs leading the rate
5 design and cost of service teams is most applicable to my
6 role here in pursuit of these types of customers for the
7 Company.

8 Q So not necessarily the current work you do as Director of
9 Electric Marketing?

10 A That's right.

11 Q O.K. Mr. Foley, my first set of substantive questions
12 will cover paragraphs 5.1.1 and 5.1.2 of the Primary
13 Supply Agreement, whose namely when the Customer is
14 required to switch to a different rate schedule. Could
15 you please pull up the hearing exhibit in your folder
16 marked MEC-16.

17 A O.K., got it.

18 Q So this document is a copy of DTE's discovery response to
19 AGDE-3.75. I will just note for the record that this
20 discovery response is also included in Exhibit AG-8 on
21 page 9 of 26 which was previously admitted. For the sake
22 of not having completing duplicative documents in the
23 record, I won't seek for this to be admitted, but if you
24 could just take a look at MEC-16 for reference. So you
25 recognize this document and sponsored this response; is

1 that correct?

2 A I do.

3 Q So DTE's answer to the request, which is broadly about
4 when the Customer might be required to switch to a rate
5 schedule, is that there are two scenarios in which the
6 Customer would switch to a new rate schedule; is that
7 correct?

8 A I believe we objected to the question, but then yes,
9 identified two situations that could be applicable to the
10 Customer needing to change rates.

11 Q So the first of those is if the Commission terminates or
12 replaces D11, the Customer would need to elect a new rate
13 schedule, correct?

14 A Yes.

15 Q Or second, if the Commission finds that the aggregate
16 costs for serving the Customer exceed the benefits, the
17 Commission could as part of relief order that the
18 Customer switch to a different rate, correct?

19 A Correct.

20 Q Mr. Foley, if subsequent to this proceeding the
21 Commission approves a different rate schedule that the
22 Customer would otherwise fall under, would the Customer
23 be required to switch to that rate schedule, and let's
24 assume that there has been no Commission finding yet that
25 aggregate costs exceed benefits?

1 A Only inasmuch as Section 5.1.2 is invoked in the
2 hypothetical you just laid out would the Customer be
3 required to change a rate schedule.

4 Q So the Commission finding that aggregate costs exceed
5 benefits?

6 A No. I referenced Section 5.1.2, which relates to the
7 Commission terminating or replacing the D11 rate.

8 Q O.K. So the first of the scenarios in the response to
9 AGDE-3.75?

10 A That's what I was referring to, yes.

11 Q O.K. But otherwise, there's no requirement for the
12 Customer to a switch to a different rate schedule under
13 the PSA?

14 MS. HAYDEN: Objection to the extent that
15 question asks for a legal conclusion.

16 JUDGE STALEY: Your response.

17 MS. LI: Let me rephrase that.

18 Q (By Ms. Li): So 5.1.2 allows that the Customer would be
19 required to switch if the Commission changes D11 and
20 creates a new rate schedule. If that doesn't happen and
21 if the Customer doesn't -- if the Commission doesn't find
22 the aggregate costs for serving the Customer exceed the
23 benefits, would the Customer have to switch to a
24 different rate schedule under any other circumstances?

25 MS. HAYDEN: Your Honor, the Company had
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1 objected to this line of questioning in the discovery
2 response because it asks -- it's fairly broad in asking
3 for any other situation that the Customer may or may not
4 have to switch a rate schedule to switch rate schedules,
5 we maintain that objection with respect to the question
6 on cross.

7 Q (By Ms. Li): Let me just limit it to one situation,
8 which is that the Commission approves a different rate
9 schedule, it doesn't replace D11. This different rate
10 schedule is one that would otherwise apply to the
11 Customer if they were signing with DTE anew without the
12 special contract. Would the Customer be required to
13 switch to that different rate schedule?

14 A Not under Sections 5.1.2 or 5.1.3, they would not be
15 required to switch.

16 Q O.K. All right. Mr. Foley, my next set of questions
17 will cover the aggregate cost and benefit reporting for
18 the Customer. I think it's described on pages 14 to 15
19 of your rebuttal testimony. So do you have the rebuttal
20 testimony open?

21 A I do.

22 Q So I'll be asking a few questions about these pages, so I
23 appreciate it if you could have those pages handy. So
24 during Mr. Wollenzien's cross, you mentioned that you are
25 responsible for the affordability backstop concept for

1 the special contracts, correct?

2 A No, I didn't say that. I contributed to the development
3 of that provision, but I was not responsible for any
4 drafting of the contracts.

5 Q O.K. Has DTE employed the affordability backstop concept
6 previously?

7 A Not that I'm aware of.

8 Q So the affordability backstop concept, it's not been
9 executed in practice yet?

10 A Not that I'm aware of.

11 Q So the mechanism of the aggregate cost and benefit
12 reporting for the Customer is broadly to compare the
13 costs to serve the Customer's load with the combination
14 of revenues received and avoided costs of serving the
15 Customer's load, correct?

16 A Yes, that's correct.

17 Q So I will refer to this accounting as the affordability
18 backstop analysis, though it is a mouthful for me to say.

19 MS. LI: So if you hear gobbledygook from
20 me, Ms. Penn, I'm probably trying to say that phrase.

21 Q (By Ms. Li): So the goal of the affordability backstop
22 analysis broadly is to ensure that the, if the costs of
23 serving the Customer's load are greater than the
24 benefits, the Customer will pay the difference?

25 A The purpose of the affordability backstop is such that

1 the Company will present aggregate costs and aggregate
2 benefits such that the Commission can determine if those
3 aggregate benefits exceed the aggregate costs, and if
4 they don't, the Commission can issue an order to address
5 that, and the Customer has agreed to comply with any
6 Commission order as such.

7 Q O.K. So in terms of that presentation, I'd like to talk
8 about some of the categories of costs that would be
9 included in the analysis, so specifically some of the
10 bullet points on pages 14 and 15 of your rebuttal. So if
11 I could first direct you to page 14, lines 23 to 25,
12 which is the third bullet point overall. "The revenue
13 requirement of renewable energy projects deployed to meet
14 the Company's Renewable Portfolio Standard (RPS)
15 obligations not covered by the CCAA." Do you see that?

16 A I do.

17 Q And the CCAA is what the Company refers to as the Clean
18 Capacity Accelerator Agreement?

19 A It is.

20 Q So you mentioned before you are generally familiar with
21 DTE's Renewable Portfolio Standards at a high level?

22 A I am.

23 Q Are you generally familiar with renewable energy credits
24 or RECs, the concept of that?

25 A I am, yes, generally aware of them.

1 Q Are you generally aware of the concept of banked RECs or
2 REC surplus?

3 A No, I'm not the right person to discuss the Company's
4 banked REC position for forecasting.

5 Q I won't ask about their position, I just want to know
6 that you know that it's possible for the Company to have
7 banked RECs or surplus RECs?

8 A Yes, I'm aware that it's possible for the Company to have
9 banked RECs or surplus RECs.

10 Q Do you know if DTE currently has banked or surplus RECs?

11 A I do not. I am not involved in the accounting of our
12 RECs.

13 Q I'm just going to switch gears really quickly. Or maybe
14 I'll ask, who at DTE is responsible for that line of
15 questioning for this proceeding?

16 A Kevin Bilyeu can discuss the Company's banked REC
17 position.

18 Q O.K. Are you able to pull up Mr. Bilyeu's direct
19 testimony at this point in time, it should be in DTE's
20 SharePoint folder?

21 A I think we can, if you give us one minute.

22 Q Sure, of course.

23 JUDGE STALEY: I'm sorry, Ms. Li, what
24 document are you looking at?

25 MS. LI: It's the direct testimony of
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1 Kevin Bilyeu.

2 JUDGE STALEY: All right, thank you.

3 A My IT issues seemed to have resolved themselves, so yes,
4 I have Witness Bilyeu's testimony in front of me.

5 Q (By Ms. Li): Great. Thank you. Can I direct you to
6 page 12 of Mr. Bilyeu's direct testimony.

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

8 Q So there are two lines, lines 7 to 8, there is a
9 reference to a projected surplus of RECs carried forward,
10 and then on lines 16, there's a reference to, "Because of
11 the VGP Special Contract build and the REC surplus, the
12 Company can reduce its planned additions...". Do you see
13 that in Mr. Bilyeu's testimony?

14 A I'm sorry, what page did you reference, I may have gone
15 to the wrong one?

16 Q Page 12.

17 A And I'm sorry, could you repeat your question?

18 Q Sure. I think I just wanted to make sure that you see
19 the testimony of Mr. Bilyeu and the references to a REC
20 surplus for DTE.

21 A I do.

22 Q Great. Do you have any reason to disagree with the
23 existence of a REC surplus?

24 A No.

25 Q Thank you. And recognizing that you just told me you

1 don't know much of the logistics, do you know if banked
2 RECs were previously paid for by other customers of DTE?

3 A I don't, I'm not the right person to respond to that
4 question.

5 Q And that would be Mr. Bilyeu who could respond to that
6 question?

7 A I believe so, yes.

8 Q But the Customer that is party to these special contracts
9 for this proceeding did not pay for banked RECs, that
10 happened before they joined DTE's service?

11 A Yes, that's correct.

12 Q And --

13 A Although I will -- sorry. If I could just add, I'm not,
14 again, I'm not the right person to respond to who paid
15 for the RECs, I'm just simply responding that the
16 Customer has not taken service from DTE at this time and
17 therefore hasn't been subject to, for example, base rates
18 or the PSQR mechanism.

19 Q Understood. Mr. Foley, the Customer's load does increase
20 DTE's RPS obligations, correct?

21 A Again, I'm not the right person, the best person to
22 respond to the Company's RPS obligations.

23 Q Got it, understood. Just for the purpose of moving
24 through my questioning, Mr. Foley, I apologize, can you
25 again look at Mr. Bilyeu's direct testimony, and this

1 time we're going to start at page 11, line 24, to page
2 12, lines 1 to 2. It states, "While the projected load
3 increases total bundled sales, only 60% of the Customer's
4 load affects the RPS target due to the VGP enrollment,
5 resulting in approximately 10.8% increase in the RPS
6 target;" do you see that language?

7 A I do.

8 Q And do you have any reason to disagree with the 10.8%
9 increase in the RPS target estimated by Mr. Bilyeu?

10 A I don't.

11 Q So hypothetically, if DTE were to use banked RECs to meet
12 its increased RPS obligations caused by the Customer's
13 load, so we've established those two points, will those
14 banked RECs be included in the affordability backstop
15 analysis?

16 A Again, I'm not the right person to talk about the use of
17 banked RECs and what costs that may be associated with
18 them or not. Inasmuch as there are incremental costs
19 caused by the Customer's load for the Company to satisfy
20 its RPS obligations, then those would be included in the
21 presentation of costs as it pertains to the affordability
22 backstop in PSA Section 5.1.3.

23 Q Understood. I think in your rebuttal testimony on page
24 14, it refers to the revenue requirement of renewable
25 energy projects that are used to meet the Customer's load

1 that's not covered by the CCAA. I think what I want to
2 know is, does the Company intend to also include the use
3 of surplus RECs or banked RECs to meet those obligations
4 as well in the affordability backstop analysis?

5 A Again, to the extent that there are incremental costs
6 that can be attributed to service of the Customer, then
7 those costs would be included in the presentative of
8 costs as it pertains to the affordability backstop.

9 Q Do you consider surplus RECs or banked RECs to be an
10 incremental cost of serving the Customer's load?

11 A Again, I'm not the right person to respond to the use of
12 banked RECs or any costs associated with that use.

13 Q But are you the right person to be able to say what would
14 go into the affordability backstop analysis?

15 A As I've said, inasmuch as there are incremental costs
16 associated with meeting the Company's RPS obligations,
17 those costs would be included in the presentment of costs
18 to serve the Customer's load as it pertains to the
19 affordability backstop.

20 Q Understood. So if we during Mr. Bilyeu's testimony he
21 confirms that surplus RECs would be an incremental cost
22 of serving the Customer's load, then that would be part
23 of the affordability backstop analysis?

24 A Yes, under that hypothetical, if there are incremental
25 costs caused by the use of RECs because we are serving

1 the Customer's load, those costs would be included in the
2 affordability backstop presentment inasmuch as those
3 costs exist.

4 Q All right. So if we go back to the third bullet of page
5 14, lines 23 to 25 -- and thank you for bearing with me
6 on this line of questioning -- it states, "The revenue
7 requirement of renewable energy projects deployed to
8 meet" -- well, I'll summarize it -- RPS obligations not
9 covered by the CCAA. So should also incremental costs be
10 included in that list of bullet points?

11 A I start that list with the sentence that says, in
12 general, the Company envisions, and so we weren't
13 intending necessarily to have every single line item. So
14 yes, to the extent that other costs, that the Company
15 incurs other costs in service of the Customer's load that
16 aren't listed here on this list, those would be -- it is
17 the Company's intent to include those in the presentment
18 of aggregate costs.

19 Q And incremental costs is part of that additional cost
20 that could be caused by the Customer's load?

21 A I'm sorry, can you repeat that question?

22 Q Oh, I was just pointing out that incremental costs isn't
23 currently in the list, I understand it's not exhaustive,
24 but it's the Company's position that the incremental
25 costs will be included in the affordability backstop

1 analysis?

2 A Inasmuch as those costs are real and attributable to the
3 provision of service to the Customer.

4 Q I'm sorry, could you explain what you mean by real?

5 A Again, because I'm not familiar with how the Company uses
6 its REC bank, I'm also not familiar with what type of
7 costs that you're referring to when you suggest that they
8 should be included in the Company's presentment of
9 aggregate costs as it relates to the affordability
10 backstop, so I use the term real simply to suggest, you
11 know, if there are actual costs that we are incurring in
12 service of the Customer, those should be included.

13 Q O.K. Maybe I'll just -- I might come back to this point,
14 Mr. Foley, I apologize, but maybe I'll ask a few
15 questions on the mechanics of the third point for revenue
16 requirements. Mr. Foley, could you please pull up the
17 hearing exhibit in your named folder that's been marked
18 MEC-17.

19 A O.K., I have it.

20 Q Great. So this document is a copy of a portion of DTE's
21 discovery response to MNSDE-2.21a. Are you familiar with
22 this document?

23 A I am.

24 Q You sponsored this discovery response?

25 A I did.

1 Q Great. So turning to MNSDE-2.21ai in paragraph 3 of your
2 answer, the second sentence of that paragraph, it states,
3 "The Company intends to evaluate in its forthcoming
4 Amended REP whether any incremental RPS compliance costs
5 to serve the Customer's load arise outside of the CCAA."
6 Do you see that statement in the response?

7 A I do.

8 Q Can you just explain to me the mechanics of how DTE will
9 determine the amounts of incremental RPS compliance
10 costs?

11 A Again, I'm not the best person to discuss our RPS
12 compliance plans or how those will be presented or
13 assessed in the Amended REP filing.

14 Q And which witness would be best to answer those
15 questions?

16 A Witness Bilyeu.

17 Q Mr. Foley, could you please pull up a hearing exhibit in
18 your folder that's been marked MEC-18.

19 A O.K., I have it.

20 Q So this document is a copy of DTE's discovery response to
21 MNSDE-1.7c. Are you familiar with this document?

22 A I am.

23 Q You sponsored this discovery response, correct?

24 A I did.

25 Q So the second paragraph of your answer notes that, "The
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1 Company will be able to attribute the associated resource
2 cost of those RPS obligations to the Customer's load."

3 Do you see that statement?

4 A Yes.

5 Q Are you able to comment on the process for how that would
6 actually happen?

7 A I think the first part of the response gives an example
8 of how that might happen. Again, this was all in the
9 context of a specific provision of the special contracts
10 and wasn't referring directly -- wasn't referring in
11 general to, for example, the Amended REP process or
12 filing.

13 Q O.K. I just was curious, are you able to talk about how
14 the Company will be able to attribute the associated
15 resource costs of RPS obligations to the Customer's load?

16 A It's my understanding that through the Amended REP
17 process, we'll be able to make that determination, but
18 again, I'm not the most appropriate person to discuss how
19 the Company will comply with its RPS obligations.

20 Q O.K.

21 MS. LI: Your Honor, I'd like to move for
22 admission of proposed Exhibit MEC-17 and MEC-18.

23 JUDGE STALEY: All right. Are there any
24 objections to the admission of hearing room Exhibits
25 MEC-17 and MEC-18?

1 Hearing none, those exhibits are admitted
2 in the record.

3 MS. LI: Thank you, your Honor.

4 Q (By Ms. Li): Mr. Foley, I'd like to discuss your
5 rebuttal on page 15 now, so lines 1 to 2, which is the
6 fourth bullet point in that list. And just to give you a
7 preview, I'm just going to be marching through the ones
8 that are costs. So this one is, "The revenue requirement
9 of other resources identified in the IRP as being caused
10 by the Customer's load." Do you see that?

11 A I do.

12 Q And I'll also direct you to Exhibit MEC-6, which was
13 attached to Dr. Woods' testimony and is actually in her
14 subfolder, so it's not in your subfolder. Are you able
15 to navigate to that?

16 A I'm sorry, what did you say the exhibit number was?

17 Q MEC-6.

18 A Yes, I have it.

19 Q Are you familiar with this document, it's DTE's response
20 to MNSDE-2.15, or 2.15a?

21 A I am.

22 Q And you sponsored this discovery response, correct?

23 A I did.

24 Q So if I could just try to summarize, and please correct
25 me if I'm wrong, so DTE's method for determining what

1 resources are caused by the Customer's load is that in an
2 IRP, the resources selected in a scenario with the data
3 center load will be compared to the scenario without the
4 data center load; is that correct?

5 A Yes, that's correct.

6 Q So the difference in resources between the scenarios with
7 and without the data center, the revenue requirements of
8 those resources will be part of the affordability
9 backstop analysis, correct?

10 A Yes, that's correct.

11 Q So if we could do an example for simplicity sake. If the
12 scenario without the Customer includes no additional
13 resources and the scenario with the Customer includes a
14 one gigawatt gas plant, what revenue requirement would be
15 included in the affordability backstop analysis?

16 A If that's the only resource addition modification or
17 change that was uncovered through that with or without
18 type analysis, then the revenue requirement of that one
19 gigawatt gas plant would be what's included in the
20 presentment of the aggregate costs in support of the
21 affordability backstop.

22 Q And if it gets a little bit more complicated, say that
23 without the Customer the scenario is a 250-megawatt gas
24 plant and with the Customer it's a 1,000-megawatt gas
25 plant, how would the revenue requirement work there?

1 A Under that hypothetical, if we have a (inaudible) --

2 COURT REPORTER: I'm sorry. ...if we
3 have a -- I didn't get you.

4 A If we removed a 250-megawatt gas plant and added a
5 1-gigawatt gas plant, we would show that the 1-gig -- the
6 revenue requirement of the 1-gigawatt gas plant is an
7 incremental cost and the removal of a 250-megawatt gas
8 plant is an incremental savings, so those would be netted
9 out in the presentment of aggregate costs and benefits in
10 support of the affordability backstop.

11 Q (By Ms. Li): It would be an avoided cost, the
12 250-megawatt gas plant?

13 A That's right.

14 Q O.K. So you also note in this discovery response -- let
15 me just get the name -- MNSDE-2.15a, in paragraph 2, the
16 last sentence, comparative modeling does not lead to a
17 direct or exclusive assignment (inaudible) --

18 COURT REPORTER: You just kind of cut out
19 there. ...does not lead to a?

20 MS. LI: I apologize.

21 Q (By Ms. Li): -- direct or exclusive assignment of
22 individual assets to the Customer. Do you see that
23 Mr. Foley?

24 A I do.

25 Q Can you explain what you mean by comparative modeling

1 would not lead to a direct assignment? It sounds like it
2 is causative to do that from the scenarios we just
3 discussed.

4 A It essentially means the resources that are caused by the
5 Customer's load as described here are not being, those
6 aren't being identified to solve for the specific needs
7 of an individual customer, they are part of a portfolio
8 of resources that we deploy to serve our total load, and
9 therefore we are looking at our total load with and
10 without the Customer and using that to identify what
11 assets are caused by, but those assets are not
12 specifically assigned to the Customer for its service.

13 Q Got it. It's just in the context of the affordability
14 backstop analysis, we would include the revenue
15 requirement -- you would include the revenue requirement
16 of that specific resource in that analysis?

17 A Yes, such that the Commission could then compare the
18 aggregate costs versus the aggregate benefits of serving
19 the Customer.

20 Q Great. And next I'd like to discuss your rebuttal at
21 page 15, line 3, which is, "Increased fuel and purchased
22 power costs." Mr. Foley, how will DTE determine if there
23 has been an increase in such costs that should be
24 attributed to the Customer?

25 A I'm not the best person to talk about how we track fuel

1 and purchased power costs associated with this specific
2 Customer or an individual customer.

3 Q And which witness would be best positioned to do that?

4 A Witness Burgdorf generally discusses our PSCR modeling.

5 Q O.K. So generally, though, it would be through the PSCR
6 proceeding to determine fuel and purchased power costs?

7 A Fuel and purchased power costs are recovered through our
8 PSCR mechanism, of which a part of that, those costs are
9 recovered through base rates and a portion of those costs
10 are recovered through a separate surcharge.

11 Q O.K. But DTE will -- there is somebody at DTE who is
12 figuring out how to attribute that to the Customer?

13 A Yes. As part of the presentation of aggregate costs for
14 the affordability backstop, we will attribute a portion
15 of our fuel and purchased power costs that Customer.

16 Q And just for my understanding, this is actual fuel and
17 purchased power costs, does DTE take into account, for
18 example, whether overall fuel costs, so the barrel
19 amount, if that's the right measurement, increases
20 because of the Customer's increased demand for fuel?

21 A Are you asking if DTE is going to try to calculate what
22 market prices would have been had we not been serving the
23 Customer?

24 Q Yes.

25 A Again, I'm not the right person to respond to how we will

1 calculate the fuel and purchased power costs attributable
2 to the Customer, so I don't know.

3 MS. LI: All right. And your Honor, just
4 to note, I have two more lines of questioning for these
5 bullet points and then I'm happy to stop at this point,
6 if I can just get through these next two.

7 JUDGE STALEY: O.K.

8 Q (By Ms. Li): So next I'd like to discuss rebuttal at
9 page 15, line 4, which is, "The revenue requirement of
10 transmission investment." Mr. Foley, could you please
11 again pull up the hearing exhibit that's been marked
12 MEC-17 and was previously admitted.

13 A Sorry, what did you say that exhibit number was?

14 Q 17. It should be within your folder, so we're not in
15 Dr. Woods' folder anymore.

16 A O.K., I'm at it.

17 Q So in paragraph -- let's do MNSDE-2.21aiv. Do you have
18 that up?

19 A I do.

20 Q So in paragraph 3 of your answer, the last sentence of
21 that paragraph, you note that, "...any transmission-
22 related costs associated with serving the Customer's load
23 would be calculated based on actual project capital costs
24 used to estimate the revenue requirement." Do you see
25 that?

1 A I do.

2 Q And recognizing that ITC Transmission is not part of DTE,
3 you don't have any control, are you aware that they have
4 estimated a cost for transmission connection for this
5 customer?

6 A I'm aware they've estimated a capital cost for their
7 construction activities related to this customer, yes.

8 Q Of 308 million?

9 A I'd have to check, but that sounds right, yes.

10 Q O.K. So just to confirm, the revenue requirement for
11 these projects when incurred will be included in the
12 affordability backstop analysis, correct?

13 A The increase in the charge that ITC puts on the Company
14 will be included in the costs as we present costs for the
15 affordability backstop.

16 Q I see. So it's not the revenue requirement of the
17 projects themselves, it's how ITC has passed that to DTE
18 that will be included in the affordability backstop
19 analysis?

20 A Yes. It's my understanding that ITC allocates a portion
21 of their costs to DTE, and so we would reflect that
22 amount, that incremental amount that gets allocated to
23 DTE in the operation of the affordability backstop when
24 we present aggregate costs.

25 Q O.K. So it's not going to be the revenue requirement of
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1 the projects themselves, it's going to be the increase in
2 incremental costs for putting those projects together
3 that's going to be included in the analysis?

4 A Yes, those two things are related inasmuch as ITC has
5 capital costs that generate a revenue requirement which
6 then gets apportioned to DTE, those are all part of the
7 same, you know, the same flow of recovery, but yes, we
8 would present the impact to DTE when we present the
9 aggregate cost of serving the Customer.

10 Q Do you know if ITC would be allocating some of the
11 transmission costs to other utilities?

12 A I don't know offhand, no.

13 Q O.K. Mr. Foley, are you aware that stability studies are
14 still ongoing for the Customer's transmission projects?

15 A I'm not aware of that, no.

16 Q I can move on. And just to follow up on the question
17 before about how ITC is going to allocate the
18 transmission costs, is there a DTE witness that would be
19 able to talk about that issue?

20 A Maybe Witness Burgdorf, but I'm not sure his involvement
21 related to how ITC allocates its costs to DTE.

22 Q O.K. And if additional transmission projects are
23 identified that are necessary to serve the Customer,
24 those will also be included in the affordability backstop
25 analysis?

1 A Yes.

2 Q O.K. And then the last line of questioning I have before
3 the break is about the revenue requirement of
4 distribution investment. So the list you provided in
5 your rebuttal testimony at pages 14 to 15 does not
6 directly reference the revenue requirement of
7 distribution investment; is that correct?

8 A That's correct, because we don't expect there to be any
9 recoverable distribution costs that would impact the
10 presentation of costs for the affordability backstop.

11 Q Got it. You've anticipated my next line of questioning,
12 but if you could just bear with me for this particular
13 exhibit. Could you please pull up the hearing exhibit
14 that's been marked MEC-19.

15 A I have it open.

16 Q So this document is a copy of discovery response to
17 MNSDE-4.1a. Are you familiar with that document?

18 A I am.

19 Q You sponsored this discovery response, correct?

20 A I did.

21 Q And this response states pretty much what you just said,
22 which is that any recoverable distribution costs over
23 50 million will be included in the affordability backstop
24 analysis, but the Company does not expect that at this
25 point?

1 A That's correct.

2 Q So if distribution costs are less than 50 million and the
3 Customer is paying for that, will DTE still present the
4 accounting of that in the affordability backstop analysis
5 or only if it's greater than 50 million will it be
6 included?

7 A It would not be included because it would not be a cost
8 to our other customers or a cost that the Company is
9 incurring simply because the Customer is reimbursing us
10 for our capital costs and, therefore, it's not relevant
11 to the accounting of costs and benefits of serving the
12 Customer.

13 Q O.K. So but if the distribution costs ultimately end up
14 being greater than 50 million, that will be included in
15 the affordability backstop analysis?

16 A Yes.

17 Q O.K. Thank you, Mr. Foley.

18 MS. LI: Can we go off the record, your
19 Honor?

20 JUDGE STALEY: Yes. We're off the
21 record.

22 (At 12:02 p.m., the hearing recessed for lunch.)

23 - - -

24

25

Tuesday, June 30, 2026

At 1:04 p.m.

- - -

(Hearing resumes following the lunch recess.)

JUDGE STALEY: All right. We are back on the record in Case No. U-22058. This is the continuation of the cross-examination of Mr. Foley and, Mr. Foley, you remain under oath. And Ms. Li, I'll turn it back over to you.

MS. LI: Thank you, your Honor.

- - -

N E A L T. F O L E Y

resumed the stand, and having been previously sworn, testified further as follows:

CROSS-EXAMINATION (Continuing)

BY MS. LI:

Q So Mr. Foley, I'd like to follow up on two points we discussed before the break, first on the issue of the surplus RECs. So earlier we discussed that to the extent they are incremental costs for serving the Customer's load, they will be reflected in the affordability backstop analysis, correct?

A Correct.

Q But surplus or banked RECs have already been obtained, so DTE already has them, the cost of those RECs has already

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1 been incurred. Are the incurred costs of surplus RECs
2 that are used to meet increased RPS obligations caused by
3 the Customer going to be part of the affordability
4 backstop analysis?

5 A The costs that you're referring to I believe would be the
6 costs of the renewable generation facilities that we
7 built prior to service of the Customer and, therefore,
8 no, those would not be included, the cost of those
9 facilities would not be included in the affordability
10 backstop since they were constructed prior to us serving
11 the Customer.

12 Q And those facilities generated RECs that are now going to
13 be used to meet RPS obligations for this Customer's load,
14 so your testimony is that those will not be included in
15 the affordability backstop analysis?

16 MS. HAYDEN: Your Honor, I would just
17 place an objection here to the extent that the question
18 does appear to state some facts not in evidence, that
19 banked RECs will in fact be used exclusively to serve the
20 Customer's load. I don't think we've established that.

21 MS. LI: I'm happy to speak in
22 hypotheticals.

23 Q (By Ms. Li): If banked RECs go to the RPS obligations
24 caused by the Customer's load, are they going to be
25 included in the affordability backstop analysis?

1 A Sorry, can you clarify what you're asking would be
2 included in the affordability analysis, affordability
3 backstop analysis?

4 Q The cost of obtaining the surplus RECs that are now going
5 to be used hypothetically to meet the RPS obligations
6 caused by the Customer's load.

7 A As we discussed previously, I'm not the best person to
8 respond to how banked or surplus RECs may be used or any
9 cost associated with their use. I was stating that the
10 renewable generation facilities that we had built prior
11 to providing service to the Customer would not be
12 included in the affordability backstop analysis because
13 those facilities were constructed prior to the Customer
14 being a part of our system.

15 Q So the surplus RECs that those facilities generated would
16 not be part of the affordability backstop analysis?

17 A Again, I'm not the best person to discuss how we will use
18 banked RECs with the costs associated with those, so I
19 can't speak to if there are any costs associated with the
20 use of those RECs. Again, the cost of the generation
21 facilities wouldn't be included because they were built
22 prior to the Customer's taking service from the Company
23 and, therefore, would not be attributable, the facility
24 cost would not be attributable to us serving the
25 Customer's load, again, because those facilities were

1 constructed prior to us serving the Customer.

2 Q O.K. I understand, Mr. Foley. What I would like to
3 avoid is Mr. Bilyeu explaining how the RECs work and then
4 not being able to answer whether or not they would be
5 part of the affordability backstop analysis because
6 that's part of your testimony. So I think my, the goal
7 that I'm trying to get to here is to get an answer to
8 whether surplus RECs used to meet increased RPS
9 obligations caused by the Customer's load, would that be
10 incorporated into the affordability backstop analysis?

11 A Again, I can't speak to how those banked RECs will get
12 used or if that will generate incremental costs that we
13 would attribute to serving the Customer and would
14 therefore be included in the affordability backstop. As
15 I think we discussed previously, to the extent that there
16 are incremental costs, that would be included in the
17 backstop analysis.

18 Q So if they are not incremental costs, they will not be
19 included?

20 A Correct. If there are no incremental costs, there would
21 be nothing to include in the affordability backstop.

22 Q O.K. And then on the fuel and purchased power costs,
23 just to confirm, do you know how the Company intends to
24 measure or report increased fuel and purchased power
25 costs in the affordability backstop analysis?

1 A No.

2 Q O.K. Mr. Foley, could you please pull up the hearing
3 exhibit that's been marked Exhibit MEC-20.

4 A O.K., I have it.

5 Q So this document is a copy of discovery response
6 MNSDE-4.2. Are you familiar with this document?

7 A I am.

8 Q And you sponsored this discovery response, correct?

9 A I did.

10 Q Can you take a look at request 4.2b. Our request was
11 aimed at how specific the reporting of costs, avoided
12 costs and benefits will be. So let me just ask first, is
13 it DTE's intention to provide a lump sum for the costs, a
14 lump sum for avoided costs, and a lump sum for benefits
15 in presenting the affordability backstop analysis?

16 A No, that is not our intent.

17 Q O.K. How specific would the report of the aggregate
18 costs and benefits be in the analysis?

19 A The specific form of how we present aggregate costs and
20 benefits has not yet been developed or finalized, so I
21 can't answer that question at this time.

22 Q Does DTE intend to provide underlying documents
23 supporting various costs, avoided costs and benefits as
24 part of the backstop analysis?

25 A Yes, in general, we would intend to provide support for
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1 the accounting of aggregate costs and benefits. I think
2 it's also important to note that we're proposing that the
3 aggregate costs and benefits be presented in rate cases
4 and PSCRs, both of which are contested and both of which
5 give parties to that case the opportunity to ask
6 questions about our presentation.

7 MS. LI: Your Honor, I'd move for
8 admission of Exhibit MEC-19 which I introduced before the
9 break and forgot to move for admission, and MEC-20.

10 JUDGE STALEY: O.K. Are there any
11 objections to the admission of Exhibit MEC-19 and MEC-20?

12 Hearing none, those exhibits are admitted
13 to the record.

14 MS. LI: Thank you, your Honor.

15 Q (By Ms. Li): So Mr. Foley, my next questions will try to
16 cover a little bit more of the logistics of the backstop
17 analysis in future proceedings, understanding that it's
18 not finalized at this point. So can you take a look at
19 pages 23 to 24 of your rebuttal testimony.

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

21 Q So these pages discuss a report that is to be filed by
22 April 15 of each year, correct?

23 A That is one component of what's covered on these pages,
24 yes.

25 Q So I'm going to ask a couple questions about the report.

1 Maybe could you please pull back up MEC-20, which was
2 just admitted.

3 A Yes, I still have it up.

4 Q Great. So DTE's response to 4.2a, and you touched on
5 this briefly just a couple questions ago, I'm still a
6 little unclear about the report. Based on your response
7 to MNSDE-4.2a, the report could be presented during rate
8 and PSCR proceedings, which are contested cases. My
9 question is, is there a universe where this report would
10 not be presented during a contested case?

11 A I'm sorry, could you say again where the word could was
12 used, I just want to make sure I'm looking at the right
13 line?

14 Q Sure. So this is for MNSDE-4.2. If we take a look --
15 maybe the word could isn't in there, but the second
16 paragraph, the last sentence, it says, "However, a
17 separate standalone case for the April 15 report would be
18 redundant since aggregate costs and benefits would be
19 presented in rate cases and PSCR proceedings, both of
20 which are contested proceedings." Do you see that?

21 A I do.

22 Q So my question is, with the report that is discussed on
23 pages 23 and 24 of your testimony, would that ever be
24 presented during a case that is not a contested
25 proceeding?

1 A So to clarify, pages 23 and 24 discuss two different
2 things: The first is a report that we propose to be,
3 that we propose would be submitted by April 15 of each
4 year, that starts on page 23, line 22, a description of
5 that report; and then separately, as discussed on page
6 24, line 17, in addition to that report, we would also
7 present aggregate costs and benefits in future rate case
8 and PSCR proceedings. So I just want to clarify when you
9 say that report, which of those two components you're
10 asking about.

11 Q The former, the one that's going to be filed by April 15
12 of each year.

13 A So as it relates to the April 15 report, as stated in my
14 rebuttal testimony, the Company is not taking a position
15 on the docket that that report would be filed in, but in
16 response to the referenced (a) and (d) discovery
17 requests, we believe filing that in a contested case
18 would be a redundant because we're already presenting
19 aggregate costs and benefits in rate cases and PSCR
20 proceedings, which are both contested.

21 Q Understood. So the Company doesn't take a position on
22 the report that's to be filed by April 15, so it's
23 possible it could be presented, that report could be
24 presented during a non-contested proceeding?

25 A Yes. Again, we haven't taken a position on the
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1 appropriate place for that report to be submitted.

2 Q But the affordability backstop analysis, the aggregate
3 cost and benefits would be presented during a contested
4 proceeding?

5 A That's correct.

6 Q And then second, in your rebuttal testimony at page 23,
7 line 24, to page 24, line 1, you note that Customer
8 information is considered confidential and will need to
9 be protected as such. Do you see that?

10 A I do.

11 Q Will DTE seek protection of Customer information such
12 that intervenors will be denied access to any information
13 in the affordability backstop analysis?

14 MS. HAYDEN: Place an objection to the
15 extent that the witness is being asked to determine legal
16 strategy with respect the presentation of information or
17 filings with the Commission.

18 MS. LI: I can rephrase, your Honor.

19 Q (By Ms. Li): Does DTE currently consider any of the
20 categories described on page, and as part of the report
21 to be confidential information?

22 A It's my understanding that yes, both the Customer's load
23 profile for the previous year as well as their maximum
24 demand for the previous year would both be Customer-
25 protected information.

1 Q And does Customer-protected information mean sort of
2 eyes-only for the Commission to see?

3 A I'm not the best person to respond to what specific
4 requirements there are to protect Customer information.

5 Q O.K. Thank you, Mr. Foley. I'm going to move on to my
6 last bucket, which would be fairly short I think. So
7 Mr. Foley, I have a few more questions related to the
8 1,600 megawatts of renewables that are part of the CCAA.
9 So I'd like to direct you to page 29, lines 21 to 22.
10 Maybe I'll wait until you get there before I get anything
11 more specific.

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

13 Q Great. So lines 20 to 21 of your rebuttal testimony,
14 which states that the Company intends to deploy the full
15 1,600 megawatts of renewable energy; do you see that
16 statement?

17 A I do.

18 Q And then can you please pull up Exhibit MEC-12, which was
19 attached to Dr. Woods' testimony and is in the Woods,
20 Bryndis folder.

21 A Can you say that exhibit number again?

22 Q Sure. MEC-12.

23 A O.K., I have it.

24 Q All right. Are you familiar with this document, this is
25 a response to CEOMEIBCIEIDE-4.41a?

1 A Yes.

2 Q You sponsored this discovery response, correct?

3 A I did.

4 Q And this response lists several situations that would
5 lead to DTE not procuring 1,600 megawatts of renewables
6 under the CCAA; is that correct?

7 A Yes, in general, these are reasons why we may not be able
8 to procure renewable generation.

9 Q And subsequent to this response, has DTE developed
10 additional situations that would lead to DTE not
11 procuring 1,600 megawatts of renewables?

12 A Not that I know of.

13 Q Has DTE considered and planned for the supply change
14 shortages described in this discovery response in order
15 to deploy the full 1,600 megawatts of renewables?

16 A I'm not the best person to respond to questions about how
17 we are planning meet the 1,600 megawatts of renewable
18 generation projects, I'm not involved in our development
19 or construction of such facilities.

20 Q And which witness would be best to answer these
21 questions?

22 A Probably Witness Bilyeu.

23 MS. LI: O.K. Your Honor, I think I'm
24 just about done with cross. Could I have a few minutes
25 just to look through my notes to see if I have any

1 lingering questions?

2 JUDGE STALEY: Yes.

3 MS. LI: I'd like to go off the record
4 for a little bit.

5 JUDGE STALEY: All right. Go off the
6 record. We're we off the record.

7 (At 1:23 p.m., brief pause.)

8 JUDGE STALEY: We are back on the record
9 in Case No. U-22058. Ms. Li.

10 MS. LI: Thank you. Mr. Foley, I have no
11 more questions for you on cross. I appreciate your time
12 and your patience.

13 THE WITNESS: Thank you.

14 JUDGE STALEY: Thank you, Ms. Li.

15 Would, Ms. Hayden, would you like to
16 confer with your client regarding redirect, or do you
17 have any redirect?

18 MS. HAYDEN: We would like to take five
19 minutes, your Honor, if we could.

20 JUDGE STALEY: All right. We'll be back
21 in five minutes. Thank you. We're off the record.

22 (Recess from 1:26 p.m. until 1:29 p.m.)

23 JUDGE STALEY: All right. We are back on
24 the record in Case U-22058. Ms. Hayden.

25 MS. HAYDEN: Thank you, your Honor. I do
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1 not have any redirect.

2 JUDGE STALEY: All right. Then I thank
3 you for your attendance today, Mr. Foley.

4 (The witness was excused.)

5 - - -

6 JUDGE STALEY: And then, Ms. Hayden, you
7 may call your next witness.

8 MS. HAYDEN: Thank you, your Honor. The
9 Company -- I'm going to transition over to
10 Mr. Janiszewski, he's going to take the next witness, and
11 that's going to be Mr. Bilyeu.

12 JUDGE STALEY: All right. Thank you.

13 MS. HAYDEN: Just be a couple minutes
14 while we get situated.

15 (At 1:30 p.m., brief pause.)

16 JUDGE STALEY: O.K. We are back on the
17 record in Case No. U-22058. And at the conclusion of the
18 testimony, the cross-examination of Neal T. Foley, I
19 neglected to discuss the admission of exhibits. So
20 Ms. Hayden had moved for the admission of Revised
21 Confidential Exhibit A-16, Revised Confidential Exhibit
22 18, and Confidential Rebuttal Exhibit A-22, knowing that
23 A-22 is only Confidential because of the signatory, to
24 protect the identity of the signatory to that document.
25 Is there any objection to the admission of those

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1 exhibits?

2 Hearing none, Revised Confidential
3 Exhibit A-16, Revised Confidential Exhibit A-18, and
4 Confidential Rebuttal Exhibit A-22 are admitted into the
5 record.

6 MR. JANISZEWSKI: Thank you, your Honor.

7 JUDGE STALEY: Thank you. All right.

8 And with that, I will turn it over to you,
9 Mr. Janiszewski, and you may call your next witness.

10 MR. JANISZEWSKI: Thank you, your Honor.

11 At this time, the Company calls Kevin L. Bilyeu to the
12 stand.

13 COURT REPORTER: Mr. Bilyeu, please raise
14 your right hand.

15 - - -

16 K E V I N L. B I L Y E U

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

20 COURT REPORTER: Thank you.

21 DIRECT EXAMINATION

22 BY MR. JANISZEWSKI:

23 Q Good afternoon, Mr. Bilyeu. Can you please state your
24 name and business address for the record.

25 A Kevin Bilyeu, One Energy Plaza, Detroit, Michigan 48226.

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1 Q And did you file with the Commission a document entitled
2 the Qualifications and Direct Testimony of Kevin L.
3 Bilyeu consisting of a cover sheet and 16 pages of
4 questions and answers?

5 A Yes.

6 Q Do you have any changes you wish to make to your direct
7 testimony?

8 A I do not.

9 Q And is that then the direct testimony you are adopting
10 today?

11 A Yes.

12 Q Are you sponsoring any exhibits associated with your
13 direct testimony?

14 A Exhibit A-2.

15 Q Were these exhibit -- was that exhibit prepared by you or
16 at your direction?

17 A Yes.

18 Q Do you have any changes you wish to make to Exhibit A-2?

19 A No.

20 Q Did you also file with the Commission a document entitled
21 the Rebuttal Testimony of Kevin L. Bilyeu consisting of a
22 cover sheet and 26 pages of questions and answers?

23 A Yes.

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

1 A Yes.

2 Q Can you please explain for the record the change you wish
3 to make to your rebuttal testimony?

4 A Yes. In my rebuttal testimony on page 15, lines 8, after
5 the word "No", removing starting with the word "The" all
6 the way through line 13.

7 Q O.K. To clarify, with that change, the answer to
8 question 24 simply reads "No"?

9 A "No", followed by the response starting at line 15.

10 Q Can you explain for the record why this change is being
11 made to your rebuttal testimony?

12 A Yes. The Company used the model from the Amended REP to
13 augment impacts from the Customer on RECs, when it
14 modeled those impacts, it made an update to the energy
15 credits obtained through REC purchases. As noted in the
16 footnote on the account, it removed RECs after 2035.
17 Inadvertently, there was a calculation error that was
18 made where the RECs, which are 5% of the RECs needed to
19 be retired that year, is pointing to the following year
20 rather than the current year, and that change, that
21 calculation is throughout the rest of the year's model,
22 which was a minor impact to the model that could be
23 corrected by acceleration of the build.

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

1 A I do not.

2 Q With the change you just described, is that then the
3 rebuttal testimony that you are adopting today?

4 A Yes.

5 Q Are you sponsoring any exhibits as part of your rebuttal
6 testimony in this case?

7 A No.

8 MR. JANISZEWSKI: Your Honor, at this
9 time, DTE Electric moves to bind into the record the
10 Qualifications and Direct Testimony and Rebuttal
11 Testimony, with the change described by Mr. Bilyeu, and
12 for the admission at the end of cross of direct Exhibit
13 A-2, and tenders Mr. Bilyeu for cross-examination. I
14 also will note that the, a redline of Mr. Bilyeu's
15 Revised Rebuttal Testimony has been uploaded onto the
16 SharePoint to provide it to Ms. Penn.

17 JUDGE STALEY: All right. Thank you. Is
18 there any objection to the binding in of the prefiled
19 Direct Testimony of Kevin L. Bilyeu, as well as the
20 prefiled Rebuttal Testimony of Kevin L. Bilyeu, as
21 revised on the record today?

22 Hearing no objections, the prefiled
23 Direct and Revised Rebuttal Testimony of Kevin L. Bilyeu
24 is bound into the record.

25 (Direct Testimony and Revised Rebuttal Testimony
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1 bound in.)

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STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of)
DTE ELECTRIC COMPANY)
for Approval of Special Contracts)
and for other relief)

Case No. U-22058

QUALIFICATIONS
AND
DIRECT TESTIMONY
OF
KEVIN L. BILYEU

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF KEVIN L. BILYEU

Line
No.

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

2 A1. My name is Kevin L. Bilyeu (he/him/his). My business address is One Energy
3 Plaza, Detroit, Michigan 48226. I am employed by DTE Electric Company (“DTE
4 Electric” or “Company”).

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

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

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

10 A3. I graduated from Walsh College in 2008 with a Bachelor of Business
11 Administration. In 2012, I received a Master of Business Administration degree
12 from the University of Michigan.

14 **Q4. What is your work experience?**

15 A4. Starting in 2006, I began my professional career with SEMCO Energy Gas
16 Company, progressing through a range of roles with increasing responsibility. In
17 2008, I took on the position of Billing Analyst, utilizing my expertise in the subject
18 matter to aid stakeholders, conducting reviews, managing projects, and devising
19 process enhancements. After that, I became Supervisor of Customer Accounting in
20 2011, leading tasks such as customer billing, remittance processing, inactive
21 collections, bad debt management, and financial reporting for the Customer
22 Accounting Department. Then, in 2013, I assumed the position of Manager,
23 Customer Energy Management, where I oversaw the administration, monitoring,
24 and development of Energy Waste Reduction (“EWR”) Programs, testified and
25 supported EWR plan and reconciliation cases at the Michigan Public Service

Line
No.

1 Commission (“MPSC” or “Commission”), and managed the home protection
2 warranty program.

3

4 In 2015, I transitioned to DTE Electric, taking on the role of Principal Marketing
5 Analyst of EWR Pilot Programs, where my responsibilities encompassed the
6 development and management of new EWR programs. In 2016, I accepted the
7 position of Principal Marketing Specialist of EWR Strategy, where my tasks
8 included modeling energy efficiency in Integrated Resource Plans (“IRP”) for long-
9 term strategy planning and developing sensitivities and recommendations to support
10 EWR plan filings with the MPSC.

11

12 In 2018, I advanced to the position of Principal Supervisor of EWR Strategy, where
13 I had overall responsibility for strategic development and planning of EWR
14 programs, including IRPs and EWR regulatory filings. Subsequently, in 2021, I
15 assumed the role of Manager for EWR Strategy and Evaluation Measurement &
16 Verification. As Manager, I had overall responsibility for strategic development and
17 planning of EWR programs, which included IRPs and EWR regulatory filings.
18 Additionally, I was responsible for ensuring program cost-effectiveness, evaluating
19 EWR programs, and applying the results to further enhance DTE Electric and DTE
20 Gas's offerings. I accepted a position as Manager for Renewable Energy Strategy
21 and Special Projects in 2023, where I supported activities related to maintaining
22 Renewable Portfolio Standard (“RPS”) compliance, planning and executing special
23 projects for renewable energy, and filing applications with the MPSC. I was
24 promoted to my current position in 2025.

Line
No.

1 **Q5. What is your current position with the Company?**

2 A5. My title is Director, Renewable Energy Planning and Strategy.

3 **Q6. What are your duties and responsibilities in your current position?**

4 A6. I continue to lead activities related to maintaining RPS compliance, planning and
5 executing special projects for renewable energy, and filing applications with the
6 MPSC, as I did in my previous role. In addition, I support activities related to land
7 acquisition, capital planning, and financial modeling for DTE Electric's renewable
8 energy portfolio.

9
10 **Q7. Have you previously sponsored testimony before the MPSC?**

11 A7. Yes. I have sponsored testimony in the following cases:

12 U-17362 SEMCO Energy Gas Company EO Plan Filing

13 U-18091 DTE Electric 2024 PURPA Filing

14 U-18419 DTE Electric Certificate of Necessity

15 U-20471 2019 DTE Electric Integrated Resource Plan

16 U-20876 2021-2022 DTE Electric EWR Plan

17 U-20881 2021-2022 DTE Gas EWR Plan

18 U-21193 2022 DTE Electric Integrated Resource Plan

19 U-21313 2022 DTE Electric and DTE Gas EWR Reconciliation

20 U-21353 2022 DTE Electric Renewable Energy Cost Reconciliation

21 U-21496 2023 DTE Electric Renewable Energy Plan Accounting Application

22 U-21550 2023 DTE Electric Renewable Energy Cost Reconciliation

23 U-21662 2024 DTE Electric Amended Renewable Energy Plan

24 U-21990 2025 DTE Electric Special Contract for Electric Service

Line
No.

1 **Purpose of Testimony**

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

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

4 1) Provide an overview of the RPS framework and compliance requirements;

5 2) Explain how Renewable Energy Credits (“RECs”) are calculated to meet DTE
6 Electric’s RPS target;

7 3) Describe the Company’s Voluntary Green Pricing (“VGP”) program included
8 within the Clean Capacity Accelerator Agreement (“CCAA”);

9 4) Detail the impact of Google LLC’s (“the Customer”) load on DTE Electric’s
10 RPS requirements;

11 5) Describe any changes in REC demand relative to the Company’s Amended
12 Renewable Energy Plan (“REP”) resulting from the Customer’s load;

13 6) Discuss the Company’s request to increase the build plan for its VGP program;

14 7) Provide a brief explanation of how revenue from the special contract is
15 recovered; and

16 8) Summarize the Company’s approach to updating its plans in future regulatory
17 filings.

18

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

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

21 Exhibit Description

22 A-2 Renewable Portfolio Standard Compliance Summary

23

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

25 A10. Yes, they were.

Line
No.

1 **Q11. How is the remainder of your testimony organized?**

2 A11. My testimony consists of the following four parts:

3 Part I: Statutory Framework

4 Part II: Clean Capacity Accelerator Agreement

5 Part III: Evaluation of the Customer's Load on DTE Electric's RPS Requirements

6 Part IV: DTE Electric's Strategy and Build Plan

7 Part V: Summary and Conclusions

8 **PART I: STATUTORY FRAMEWORK**

9 **Q12. What are the RPS targets established in Public Act 235 of 2023 ("PA 235")?**

10 A12. PA 235 establishes that an electric provider shall achieve a REC portfolio of at least
11 the following:

12 a) Through 2029, 15% of total retail sales

13 b) In 2030 through 2034, 50% of total retail sales

14 c) In 2035 and each year thereafter, 60% of total retail sales

15

16 **Q13. What total retail sales figure does the Company use to determine its RPS**
17 **targets?**

18 A13. Consistent with Section 28(2)(b) of PA 235, the Company uses weather normalized
19 megawatt-hours of bundled load sold during the previous year, less the amount of
20 sales attributable to customers participating in a VGP program and the outflow from
21 customers participating in the distributed generation program.

Line
No.

1 **Q14. How are RECs generated to meet the RPS targets?**

2 A14. In general, one REC is granted for each megawatt hour of electricity generated from
3 the renewable energy system. RECs can be generated through several methods
4 outlined in Section 28(5) of PA 235. This includes “(a) Generating electricity from
5 renewable energy systems for sale to retail customers. (b) Purchasing or otherwise
6 acquiring renewable energy and capacity. (c) Purchasing or otherwise acquiring
7 renewable energy credits without the associated renewable energy or capacity...”
8 REC-only purchases made under Section 28(5)(c) shall not exceed 5% of the
9 Company’s compliance amount.

10

11 **Q15. Can RECs be banked if not used towards RPS compliance in the year in which**
12 **they are generated?**

13 A15. Yes. Under Section 39(3) of PA 235, “A renewable energy credit expires at the
14 earliest of the following times: (a) When used by an electric provider to comply
15 with its renewable energy standard. (b) When substituted for an energy waste
16 reduction credit under section 77. (c) Five years after the end of the month in which
17 the renewable energy credit was generated.” Based on this provision, DTE Electric
18 may bank RECs for up to five years from their creation date.

19

20 **Q16. What is the purpose of the Company’s VGP programs?**

21 A16. Section 61 of 2016 Public Act 342 mandated that all utilities offer voluntary
22 renewable energy programs to their customers. Voluntary green pricing programs
23 allow customers to choose how much of their electricity usage will be supported by
24 renewable energy. Under this program, the electric provider offers a set of
25 renewable energy options, and customers may elect the portion of their electricity

Line
No.

1 that they want to be sourced from renewable generation. Participation is optional,
2 and the program is designed to give customers a direct, flexible way to increase
3 their use of renewable energy beyond renewable portfolio standards.
4

5 **Q17. How do sales associated with VGP programs impact RPS requirements?**

6 A17. As noted above, load participating in the Company's VGP program is removed
7 from the bundled retail load, thereby lowering the RPS obligation. When a
8 customer enrolls, whether through the standard offering or a special contract, the
9 enrolled portion of their load does not contribute to increases in RPS targets.
10

11 **Q18. Does the Company offer VGP special contracts to accommodate unique**
12 **customer situations?**

13 A18. Yes. In the June 9, 2021 Order in Case No. U-20713, the Commission approved a
14 settlement agreement ("Section 61 Settlement Agreement") that established a
15 customer requested offering within the Company's VGP program. This offering
16 supports unique, customer driven renewable energy projects that fall outside the
17 standard Rider 17 options. Under this structure, the Company designs and
18 constructs dedicated renewable energy projects that support each participating
19 customer's specific sustainability goals.
20

21 **Q19. Do VGP special contracts require customers to pay for all of the associated**
22 **costs from the renewable energy projects that supply their VGP special**
23 **contracts?**

24 A19. Yes. All costs associated with the development of the renewable energy project(s)
25 to supply VGP special contracts are fully recovered through the subscription fees

Line
No.

1 that are featured in the VGP special contracts and are billed to the subscriber. Any
2 early termination or default of the contract from the subscriber's actions or
3 inactions results in a termination fee, designed to ensure all costs of participation
4 and termination are borne by subscribers and that no costs are subsidized by non-
5 subscribers.

6

7

PART II: CLEAN CAPACITY ACCELERATOR AGREEMENT

8 **Q20. Is the Customer enrolling in a VGP Special Contract within the CCAA?**

9 A20. Yes, the Customer has requested that the Company build up to 1.6 GW of
10 renewable energy projects through a VGP special contract with DTE Electric.
11 Rather than entering into a standalone special contract for customer requested
12 renewable energy projects, the VGP Special Contract terms were incorporated into
13 the CCAA. The CCAA outlines the terms and conditions governing the agreement
14 between the Customer and DTE Electric. The CCAA terms governing the
15 deployment of renewable energy comply with the Section 61 Settlement Agreement
16 discussed above. Therefore, the renewable energy resources included in the CCAA
17 are considered part of a customer-requested VGP special contract and treated as
18 such for RPS purposes. Throughout my testimony, I refer to the relevant CCAA
19 terms as "VGP Special Contract." Refer to Witness Foley's testimony which
20 provides additional details regarding the CCAA.

21

22 **Q21. What portion of the Customer's load is enrolled in a VGP Special Contract?**

23 A21. The Customer has chosen to enroll 40% of their total load in a VGP Special
24 Contract, thereby reducing the RECs required by the Company for compliance.

Line
No.

1 Under this VGP Special Contract, the Company will deploy a portfolio of
2 renewable energy projects to support the enrolled portion of the Customer's load.

3

4 **Q22. Will the portion of load covered under the VGP Special Contract enable the**
5 **Customer to reach 100% renewable energy?**

6 A22. Yes. Many large customers use the RPS to meet a considerable share of their clean
7 energy targets and rely on VGP programs to close the remaining gap to reach goals
8 such as 100% renewable energy. By allocating 1.6 GW to a VGP Special Contract,
9 the Customer may claim 100% renewable energy usage once the Company hits the
10 60% RPS target. See Table 1 below for additional details.

11

12 Table 1 Customer Build Required to Support 100% Renewable Energy

13

Claim

Customer Load	7,884 GWh¹
Converted to GW ²	4.0 GW
Renewable Energy from RPS by 2035	60%
Gap from RPS and 100% Renewable Energy Target	40%
VGP GW to achieve 100% Renewable Energy	1.6 GW

14

15 **Q23. How is the Company proposing to recover the revenue associated with the**
16 **additional build required to fulfill the VGP Special Contract?**

17 A23. Under the CCAA, the Company will develop a portfolio of renewable energy
18 projects to meet the Customer's needs. The Customer will cover the full cost (i.e.,
19 the revenue requirement) of these projects over their depreciable life, enabling the

¹ Estimate is based on an assumed load factor of 88.5%.

² 7,884 GWh / 8760 Hours Annually / 22.5% Solar NCF = 4.0 GW

Line
No.

1 Company to recover the associated revenue from the new investments. The CCAA
2 will ensure no costs related to Customer projects are paid for by other customers.
3 Witness Foley's testimony provides additional detail on how the revenue
4 requirement for this project portfolio is determined and recovered.
5

6 **PART III: EVALUATION OF THE CUSTOMER'S LOAD IMPACTS ON DTE**

7 **ELECTRIC'S RPS REQUIREMENTS**

8 **Q24. What does Exhibit A-2, "Renewable Portfolio Standard Compliance**
9 **Summary" include?**

10 A24. Exhibit A-2 is an updated analysis of my Exhibit A-2 in the Company's Amended
11 REP, Case No. U-21662. It summarizes the key data underlying the Company's
12 RPS requirement. This exhibit is formatted in a similar manner but has the addition
13 of rows to represent updated information associated with the addition of the
14 Customer's load. The first update is the incremental data center load added in Line
15 6. Incremental VGP sales are then subtracted in Line 10. These two updates provide
16 an updated RPS Requirement as shown in Line 19. Line 24 has also been updated
17 to reflect 5% of the REC requirement in REC-only purchases through 2035. The
18 resulting REC balance without additional generation is then calculated in Line 29.
19 Lines 31-32 are a reference only for the base case values in the Amended REP Case
20 No. U-21662. Line 34 shows the RPS requirement when updating for the first data
21 center load approved in Case No. U-21990, which is an incremental step before
22 Line 35 which shows the RPS requirement after adding the Customer's load. Line
23 37 then gives the resulting REC balance after factoring in the additional 1.8 GW
24 from the first customer, 1.6 GW of VGP from the second customer, and a 250 MW
25 reduction of compliance build.

Line
No.

1 **Q25. What assumptions were considered when assessing the Customer's impact on**
2 **DTE Electric's RPS requirements?**

3 A25. To evaluate the Customer's impact on the Company's RPS requirements, the
4 Company relied on assumptions from the most recently approved Amended REP
5 and on data from the first data center customer approved in Case No. U-21990³.
6 Excluding tax credits, these Amended REP assumptions were applied to new
7 renewable energy build for the Customer. The assumptions also reflect the first data
8 center customer's impact on REC compliance and the 1.8 GW of additional
9 renewable build assumed for that customer. The projected impact on RPS
10 compliance and incremental build is shown in Line 34 of Exhibit A-2.

11

12 **Q26. What is the projected increase in DTE Electric's load resulting from the**
13 **Customer?**

14 A26. As discussed in Company Witness Foley's testimony, the Customer's max load will
15 be 1 GW and their annual usage would be approximately 7.88 TWh.

16

17 **Q27. Relative to the Company's latest Amended REP and including the first data**
18 **center customer's load, what is the revised RPS target after adjusting for the**
19 **Customer's load?**

20 A27. The RPS target from the Company's most recent Amended Renewable Energy
21 Plan, Case No. U-21662, is presented in Line 31 of Exhibit A-2, with the inclusion
22 of the first data center customer's load factored in for Line 34. The updated RPS
23 target reflecting the Customer's load adjustments is shown in Line 35 of Exhibit A-
24 2. While the projected load increases total bundled sales, only 60% of the

³ Assumptions used from the approved Amended REP Case No. U-21662, include installed costs, net capacity factors, commercial operating dates, etc.

Line
No.

1 Customer's load affects the RPS target due to the VGP enrollment, resulting in an
2 approximate 10.8% increase in the RPS target, calculated by comparing the sum of
3 Line 35 to the sum of Line 34.

4

5 **Q28. How will the Company adjust its renewable build plan, given the load enrolled**
6 **in the VGP Special Contract, to ensure it meets its RPS targets?**

7 A28. With 40% of customer load participating in the VGP Special Contract, and with a
8 projected surplus of RECs carried forward, the Company is able to pursue an
9 efficient and cost-effective approach to its renewable build plan. Between 2030
10 through 2032, the Company plans to construct up to 1.6 GW⁴ of new renewable
11 capacity dedicated to serving the Customer's VGP Special Contract load. The
12 Customer and DTE Electric have agreed that this timeframe is flexible and may
13 shift as needed. This renewable energy build not only supports the Customer but
14 also creates flexibility in later years.

15

16 Because of the VGP Special Contract build and the REC surplus, the Company can
17 reduce its planned additions by 200 MW in 2033 and 50 MW in 2034, directly
18 lowering costs for RPS customers without compromising compliance. This
19 approach positions the Company to achieve the 60% RPS requirement by 2035
20 while maintaining a positive REC balance throughout the period, as shown on line
21 37 of Exhibit A-2.

22

23 **Q29. With these additions to the REP, is the Company still projected to achieve the**
24 **RPS targets under PA 235?**

⁴ 500 MW in 2030, 700 MW in 2031, and 400 MW in 2032 (a total of 1,600 MW)

Line
No.

1 A29. Yes. With the additional 1.6 GW enrolled in the VGP Special Contract, the
2 Company can maintain a positive REC balance and meet the RPS requirements
3 under PA 235. Line 37 of Exhibit A-2 shows the REC balance reflecting the
4 proposed VGP capacity adjustments.

5

6 **Q30. If the Customer covers the full revenue requirement for the Special Contract**
7 **build, do they still pay their share of RPS assets through the power supply cost**
8 **recovery (“PSCR”) mechanism?**

9 A30. Yes. With the Customer being subject to the PSCR, they will contribute to the
10 Company’s existing and future renewable and transmission costs. This ensures any
11 incremental renewable generation for RPS compliance associated with the
12 Customer’s load is appropriately offset. Witness Burgdorf’s testimony and Exhibits
13 A-9 and A-10 provide a breakdown of the costs the Customer will pay through the
14 PSCR.

15 **PART IV: DTE ELECTRIC’S STRATEGY AND BUILD PLAN**

16 **Q31. Does the Company expect that sufficient renewable energy projects will be**
17 **available to support the VGP Special Contract?**

18 A31. Yes. DTE Electric has a robust and diversified strategy to meet the renewable
19 energy build requirements associated with the VGP Special Contract. The
20 Company’s approach could include a combination of:

21

22 1. **Company-Owned Projects:** DTE Electric is actively developing new wind
23 and solar facilities, with many projects already in the pre-construction or
24 permitting phases.

Line
No.

1 2. **Strategic Acquisitions:** Where feasible, DTE Electric will evaluate
2 acquisition opportunities for operational or near-operational renewable
3 assets that can be integrated into its portfolio to accelerate compliance
4 timelines.

5 3. **Request for Proposal (“RFP”):** DTE Electric will issue an RFP for a
6 minimum of 50% of the capacity required to fulfill the VGP Special Contract
7 through build transfer agreements (“BTAs”) with unaffiliated third parties
8 consistent with the Section 61 Settlement Agreement in Case No. U-21172.

9
10 **Q32. Is the Company seeking approval, within this proceeding, for the 1.6 GW**
11 **required to support the VGP Special Contract as part of its Amended REP?**

12 A32. Yes. The Company is requesting approval to include additional renewable energy
13 builds up to 500 MW by 2030, 700 MW by 2031, and 400 MW by 2032 (a total of
14 1.6 GW) in its Amended Renewable Energy Plan to support the VGP Special
15 Contract. The Company believes that such inclusion is consistent with 2008 PA
16 295, as amended by 2023 PA 235, Section 9 of the Settlement Agreement in the
17 Company’s Section 61 filing Case No. U-20713, and all other applicable law. As
18 projects are selected to meet the 1.6 GW requirement, each will be filed with the
19 Commission for approval, consistent with the current project approval process used
20 for VGP special contracts.

21

22 **Q33. Has the Commission provided guidance on the renewable energy build plan**
23 **assumptions in an Amended REP?**

24 A33. Yes. In the April 25, 2024 Order in Case No. U-21568, the Commission held “IRPs
25 remain the most appropriate venue to consider generation diversity as well as

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1 renewable resource planning because IRPs allow for the full assessment of
2 renewable resources against other resources (including the consideration of the
3 value of the various resource types and attributes as expressed by commenters). In
4 turn, future amended REPs should reflect the assumptions included in the
5 providers' most recently approved IRP."

6

7 **Q34. When is the Company expected to submit its next Amended REP**
8 **incorporating the Customer's load impacts?**

9 A34. In accordance with the order in Case No. U-21990, the Company will file its next
10 Amended REP alongside its IRP later in 2026. As part of the IRP process, the
11 Company will assess any changes to its renewable portfolio through modeling
12 optimization and develop a strategy to support RPS compliance.

13 **Q35. Does the timing of these filings provide DTE Electric with sufficient**
14 **opportunity to address the increased RPS requirements associated with the**
15 **Customer's load?**

16 A35. Yes. The timing of the 2026 IRP and Amended REP aligns well with the anticipated
17 load ramp for the Customer. This provides DTE Electric with a multi-year planning
18 window to develop its renewable energy strategy accordingly.

19

20 The 2026 IRP will detail DTE Electric's approach to maintaining RPS compliance.
21 The 2026 Amended REP will further define these plans, detailing DTE Electric's
22 REC acquisition strategy and further ensuring compliance with RPS targets.
23 Together, these filings provide a structured and timely framework to accommodate
24 the incremental load while maintaining regulatory compliance.

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1

PART V: SUMMARY AND CONCLUSIONS

2

Q36. Is DTE Electric well-positioned to meet the increased RPS requirements associated with incremental Customer load?

3

4

A36. Yes. DTE Electric remains committed to supporting the RPS and has a defined path for achieving the additional REC requirements driven by the Customer load. My testimony and exhibits in this filing demonstrate that:

5

6

7

1. With the requested 1.6 GW to support the Customer's VGP Special Contract, the Company can maintain a positive REC balance and meet the RPS requirements;

8

9

10

2. The Company's existing renewable energy portfolio and development pipeline offer a credible and sufficient foundation to meet the elevated renewable energy targets.

11

12

13

3. DTE Electric will reassess its renewable energy build plan in its next IRP filing, which will include consideration of the additional load and REC requirements;

14

15

4. The 1.6 GW supporting the Customer's VGP Special Contract provides incremental customer benefit by enabling a 250 MW reduction by 2034, which directly lowers costs for RPS customers through the addition of this new load.

16

17

18

19

Q37. Does this conclude your direct testimony?

20

A37. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of)
DTE ELECTRIC COMPANY)
for Approval of Special Contracts)
and for other relief)

Case No. U-22058

REVISÉD REBUTTAL TESTIMONY

OF

KEVIN L. BILYEU

DTE ELECTRIC COMPANY
REVISED REBUTTAL TESTIMONY OF KEVIN L. BILYEU

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

3 A1. My name is Kevin L. Bilyeu (he/him/his). My business address is One Energy
4 Plaza, Detroit, Michigan 48226. I am employed by DTE Electric Company (“DTE
5 Electric” or “Company”).

6

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

9 A2. Yes.

10

11 **Purpose of Testimony**

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

13 A3. The purpose of my rebuttal is as follows:

14 A. Respond to the recommendations and assumptions made by Michigan Public
15 Service Commission (“MPSC” or “Commission”) Staff (“Staff”) Witness
16 Simpson, specifically related to: (1) the recommendation that Voluntary Green
17 Pricing (“VGP”) sales may only be excluded from the Renewable Portfolio
18 Standard (“RPS”) compliance calculation if the associated Renewable Energy
19 Credits (“RECs”) are retired, and (2) the recommendation that DTE Electric be
20 required to apply the MPSC Competitive Procurement Guidelines;

21 B. Respond to the recommendations made by Witness Woods on behalf of
22 Michigan Environmental Council, Natural Resources Defense Council, and
23 Sierra Club (“MNS”), specifically regarding: (1) the need for detailed project
24 information demonstrating the ability to meet the Customer’s (Google, LLC)
25 renewable energy demand, (2) the appropriateness of historical REC surplus

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1 trends relative to forecasted surpluses, and (3) the impact of a calculation error
2 on RPS compliance;

3 C. Respond to the recommendations and assumptions made by The Ecology
4 Center, Environmental Law & Policy Center, Union of Concerned Scientists,
5 and Vote Solar, Michigan Energy Innovation Business Council, and the
6 Institute for Energy Innovation (collectively “MEICEO”) Witness Sherman,
7 specifically related to her renewable energy ownership proposal, and MEICEO
8 Witness Shaver regarding his testimony on the applicability of annual REC-
9 based matching and 24/7 matching under DTE Electric’s VGP framework; and
10 D. Respond to concerns raised by Great Lakes Renewable Energy Association
11 (“GLREA”) Witness Richter regarding potential RPS compliance risk
12 associated with large-load and VGP demand.

13

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

15 A4. No.

16

17 **REBUTTAL TO STAFF WITNESS SIMPSON**

18 **1. Voluntary Green Pricing REC Retirement**

19 **Q5. Staff Witness Simpson argues on pages 11-14 of her testimony that VGP sales**
20 **should not be removed from the RPS compliance calculation unless the**
21 **associated RECs are retired. Do you agree?**

22 A5. No. While I agree that mechanisms must exist to prevent double counting of
23 renewable attributes, I disagree that DTE Electric must be the entity responsible for
24 the retirement of RECs in order for VGP sales to be removed from the RPS
25 compliance calculation.

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1 Neither MCL 460.1061 nor the Commission's orders require utility retirement as
2 the exclusive means of demonstrating that renewable energy is attributable to a
3 VGP customer. The order cited by Staff from Case No. U-18349 specifically says
4 just the opposite, that "it may be advantageous to provide an option for the customer
5 to own and retire any RECs generated under the [VGP] program."

6

7 **Q6. Why is the distinction between REC retirement and REC ownership**
8 **important?**

9 A6. A REC represents the renewable attribute associated with one megawatt-hour of
10 renewable generation. Transferring a REC does not eliminate or invalidate the
11 renewable nature of the underlying energy. It simply transfers ownership of the
12 renewable attribute from one party to another.

13

14 Accordingly, a REC transferred to the Customer remains a valid REC representing
15 renewable energy. The transfer does not convert renewable energy into non-
16 renewable energy, nor does it create any deficiency in renewable generation. It
17 simply changes which entity has the right to claim the environmental attributes
18 associated with that renewable energy.

19

20 **Q7. Does MCL 460.1061 require the retirement of RECs associated with VGP**
21 **sales?**

22 A7. No. The statute requires that participating customers be able to specify the amount
23 of electricity attributable to them that will be renewable energy. The statute does
24 not require that DTE Electric retire the RECs on the customer's behalf.

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1 Had the Legislature intended to require retirement of RECs in all circumstances, it
2 could have expressly stated so.

3

4 **Q8. Staff Witness Simpson argues that VGP sales should only be removed from**
5 **the RPS denominator when RECs are retired. How do you respond?**

6 A8. Staff Witness Simpson's position effectively adds a requirement that does not
7 appear in the statute. The applicable policy objective is preventing double counting.
8 That objective can be fully achieved through appropriate REC ownership, tracking,
9 assignment, transfer, and reporting.

10

11 Whether DTE Electric retires RECs on the Customer's behalf or transfers RECs to
12 the Customer, the key compliance safeguard is that those RECs are not also used
13 by DTE Electric for RPS compliance. Proper REC tracking and reporting can
14 ensure that the same renewable attribute is not counted both for the Customer's
15 VGP participation and for DTE Electric's RPS compliance obligation.

16

17 The identity of the REC owner or retiring party does not change the underlying
18 renewable nature of the generation, but it does determine who controls the
19 associated renewable attribute and who may make the related claim.

20 The critical safeguard is that RECs associated with the Customer's VGP
21 participation must not also be used by DTE Electric to satisfy its RPS compliance
22 obligation for non-VGP retail sales. Once those RECs are transferred to the
23 Customer or retired on the Customer's behalf, they are not available for DTE
24 Electric to count toward its RPS compliance. Accordingly, Staff is correct that the

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1 Company must maintain REC accounting sufficient to prevent double counting, but
2 I disagree with Staff Witness Simpson that mandatory DTE Electric retirement is
3 the only means of accomplishing that objective.

4

5 **Q9. Why is the Customer's role significant in this proceeding?**

6 A9. The Customer's role is significant because it is not simply purchasing renewable
7 energy from an existing program. Rather, the Customer has agreed to support the
8 development of up to 1,600 MW of renewable energy resources through a VGP
9 Special Contract and will bear the associated costs of those resources.

10

11 As a result, the Customer has a direct economic interest in both the renewable
12 energy produced by the projects and the associated renewable attributes. The
13 arrangement reflects a customer-driven investment in renewable energy that goes
14 beyond the requirements imposed on DTE Electric under PA 235.

15

16 Accordingly, a customer that is funding renewable development should have
17 flexibility regarding how those attributes are managed, provided appropriate
18 safeguards exist to prevent double counting. Requiring all RECs be retired would
19 deprive the Customer of a fundamental and valuable component of the product it is
20 purchasing.

21

22 **Q10. Staff Witness Simpson cites Commission language from Case No. U-18349**
23 **regarding the tracking and retirement of RECs under VGP programs on page**
24 **13 of her testimony. Does that language require utility retirement in every**
25 **VGP program?**

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1 A10. No. The language cited by Staff does not require utility retirement in every VGP
2 program. The Commission recognized in Case No. U-18349 that REC tracking
3 systems should be used to ensure that RECs generated under VGP programs are
4 properly assigned and retired and are not double counted. The “own and retire”
5 language in U-18349 arises in the context of large C&I customers being given the
6 option to “own and retire any RECs generated under the program.” That option has
7 been preserved here, as the VGP Special Contract likewise allows for customer
8 ownership and retirement of RECs.

9
10 Accordingly, U-18349 supports the anti-double-counting principle, but it does not
11 establish mandatory utility retirement as the exclusive means of satisfying that
12 principle. The key safeguard is that RECs associated with the Customer’s VGP
13 participation must be properly tracked and must also not be used by DTE Electric
14 for RPS compliance. Interpreting U-18349 to prohibit customer ownership or to
15 require DTE Electric itself to retire every REC associated with VGP sales would
16 go beyond the Commission’s stated language. Further, as just described, such an
17 approach would be contrary to the strong interest certain large customers have in
18 owning, managing, and retiring RECs on their own.

19

20 **Q11. What implications could Staff Witness Simpson's recommendation have for**
21 **other large VGP customers?**

22 A11. Staff Witness Simpson's recommendation could have implications that extend
23 beyond the specific facts of this proceeding. Large customers participating in VGP
24 special contracts may have different renewable energy procurement objectives and
25 reporting requirements. These customers are sophisticated energy consumers with

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1 substantial renewable energy objectives. So long as double-counting is avoided,
2 there is no environmental or renewable benefit to taking Staff Witness Simpson's
3 approach, and in fact such rigidity could harm results to the extent DTE Electric
4 customers have customer-specific approaches to their consumption and treatment
5 of renewable energy. As a result, DTE Electric has historically offered participating
6 customers flexibility regarding the treatment of RECs, including the option for DTE
7 Electric to retire the RECs on its behalf or to transfer the RECs to the customer.

8

9 For example, customers such as Ford, Stellantis, and University of Michigan are
10 also offered the same flexibility regarding their RECs. These VGP special contract
11 customers typically maintain sophisticated sustainability programs and often
12 manage their own REC portfolios. Accordingly, the Commission should consider
13 not only the impact on this particular Customer, but also the broader implications
14 for existing contracts, customer flexibility, and the continued attractiveness of VGP
15 for large customers interested in supporting renewable energy development.

16

17 **Q12. What is your conclusion regarding Staff Witness Simpson's recommendation?**

18 A12. Staff Witness Simpson correctly identifies the importance of preventing double
19 counting of renewable attributes. Specifically, on page 15 of her testimony she
20 states, "RPS compliance and Clean Energy Plan ("CEP") compliance must align to
21 ensure that RECs are only used once." However, Staff Witness Simpson incorrectly
22 concludes that retirement of RECs is the only acceptable means of accomplishing
23 that objective. This comes down to a tracking and verification issue, not a
24 requirement that DTE Electric be the entity that retires every REC associated with
25 VGP sales. The Company will maintain appropriate REC records to ensure that

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1 RECs associated with the Customer's VGP participation are not also used by the
2 Company for RPS compliance in a manner that would result in double counting.

3

4 The appropriate standard is that the RECs associated with VGP sales must not be
5 used by DTE Electric for RPS compliance and must be subject to appropriate
6 tracking and verification controls. Whether those RECs are retired by DTE Electric
7 on behalf of the customer or transferred to the customer does not alter the renewable
8 nature of the generation, does not create double counting, and does not conflict with
9 MCL 460.1061.

10

11 2. Competitive Procurement Guidelines

12 **Q13. Staff Witness Simpson recommends on page 11 of her testimony that DTE**
13 **Electric be required to apply the Competitive Procurement Guidelines**
14 **established in Case No. U-20852 for procuring resources to fulfill the CCAA.**
15 **Do you agree?**

16 A13. Not as a blanket requirement for all resources supporting the CCAA, because I do
17 not agree the Competitive Procurement Guidelines should apply to the renewable
18 resources supporting the VGP Special Contract. As explained by Company Witness
19 Foley in his revised direct testimony, the Company intends to use the Competitive
20 Procurement Guidelines in the 2026 Energy Storage Request for Proposal ("RFP")
21 but the renewable resources under the VGP Special Contract will be selected
22 consistent with the Commission-approved settlement agreements in Case Nos. U-
23 20713/U-20851 and U-21172 ("VGP Settlement Agreements"). Procurement for
24 VGP special contracts is governed by the VGP Settlement Agreements, which
25 establish the applicable competitive procurement framework for

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1 customer-requested special contracts, including build-transfer solicitations and
2 customer-specific procurement requirements.

3

4 The VGP Settlement Agreements also recognize that procurement approaches for
5 special contracts may be tailored to the needs of the participating customer. DTE
6 Electric intends to procure resources for the VGP Special Contract in accordance
7 with those approved provisions. As a result, this proceeding is not the appropriate
8 forum to revisit or modify the previously approved VGP Settlement Agreements or
9 impose additional procurement requirements that would alter the negotiated VGP
10 Special Contract framework.

11

12 **Q14. Staff Witness Simpson recommends on page 11 of her testimony that DTE**
13 **Electric prioritize resources needed for the Company's Integrated Resource**
14 **Plan ("IRP") and all customers before selecting resources for the CCAA, so**
15 **that the Customer does not pay less for resources of the same technology type**
16 **contracted at a similar time for purposes of meeting IRP, Amended REP, or**
17 **CEP needs. Do you agree?**

18 A14. I agree with the general principle that the CCAA should not cause other customers
19 to subsidize the Customer's renewable resources. However, procurement for
20 customer-requested VGP special contracts is already governed by Commission-
21 approved settlement provisions in Case Nos. U-20713/U-20851 and U-21172.
22 Staff's recommendation would effectively add a new procurement-priority
23 condition to that approved framework, which is not necessary or appropriate in this
24 proceeding.

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1 Additionally, Staff Witness Simpson's proposed comparison between resources
2 contracted under the CCAA and resources procured for the IRP, Amended REP, or
3 CEP is not as straightforward as comparing technology type and timing. Whether
4 resources are comparable depends on the specific procurement framework and
5 project attributes, and the customer-specific obligations the resource is intended to
6 satisfy. A resource procured for a customer-specific VGP special contract may be
7 subject to different commercial requirements, eligibility criteria, risk allocations, or
8 customer-requested attributes than a resource procured for general system needs.
9 As a result, a price difference between resources of the same technology type and
10 similar contractual timeframe would not, by itself, demonstrate that the Customer
11 is receiving preferential treatment or that other customers are paying more for
12 certain resources.

13

14 **REBUTTAL TO MICHIGAN ENVIRONMENTAL COUNCIL, NATURAL**

15 **RESOURCES DEFENSE COUNCIL, AND SIERRA CLUB WITNESS**

16 **WOODS**

17 *1. Detailed Project Information*

18 **Q15. On page 26 of her testimony, MNS Witness Woods questions DTE Electric's**
19 **statement that it maintains a robust set of renewable energy projects in various**
20 **stages of development to support the Customer's anticipated load growth.**
21 **Why is DTE Electric confident it can meet the Customer's future renewable**
22 **energy needs?**

23 A15. DTE Electric is confident because it maintains an active and ongoing renewable
24 development pipeline consisting of projects at various stages of evaluation,
25 development, permitting, contracting, and construction. Maintaining a pipeline of

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1 projects in different stages of development is a standard planning practice that
2 provides flexibility to respond to evolving customer needs, changing load forecasts,
3 project timing considerations, and market conditions.

4

5 The purpose of maintaining a development pipeline is not to commit a specific
6 future customer need to a specific project in advance. Rather, it is to ensure that
7 sufficient renewable development opportunities exist to meet future resource needs
8 as those needs materialize. DTE Electric's development process is designed to
9 provide that flexibility.

10

11 **Q16. Is it necessary in this proceeding to identify every future project that may**
12 **ultimately serve the Customer's load growth?**

13 A16. No. The question in the instant case is whether DTE Electric possesses the planning
14 processes, development capabilities, and project pipeline necessary to procure
15 renewable resources when needed, and it does. The issue is not whether every future
16 renewable project has already been selected or approved.

17

18 The Customer's renewable energy needs will occur over multiple years. Requiring
19 DTE Electric to identify today the specific projects that may ultimately serve future
20 load growth would be inconsistent with prudent planning and would unnecessarily
21 constrain DTE Electric's ability to optimize project selection as circumstances
22 evolve.

23

24 **Q17. Has DTE Electric successfully developed and brought renewable projects**
25 **online in the past?**

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1 A17. Yes. DTE Electric has substantial experience developing, acquiring, and integrating
2 renewable resources to serve customers and satisfy renewable energy requirements,
3 with over 2,600 megawatts of renewable energy currently online. This experience
4 supports DTE Electric's ability to identify, evaluate, procure, and develop
5 renewable resources as needed.

6

7 **Q18. Beyond its existing renewable development pipeline, does DTE Electric have**
8 **other tools available to identify renewable resources needed to serve the**
9 **Customer's load growth?**

10 A18. Yes. In addition to maintaining a portfolio of renewable energy projects in various
11 stages of development, DTE Electric conducts competitive RFPs to identify
12 additional renewable resources. Competitive solicitations are a well-established
13 component of DTE Electric's resource planning process and provide another
14 mechanism for identifying renewable energy opportunities capable of meeting
15 customer needs.

16

17 **Q19. Will the Commission have an opportunity to review DTE Electric's renewable**
18 **development plans in greater detail?**

19 A19. Yes. DTE Electric expects to provide more information regarding its future
20 renewable resource plans in its upcoming IRP and amended Renewable Energy
21 Plan ("REP"), which are expected to be filed concurrently later this year.

22

23 Those proceedings are specifically designed to evaluate resource planning
24 decisions, projected load growth, renewable resource needs, project portfolios,
25 timing considerations, and long-term resource development strategies. They

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1 provide a more appropriate forum for detailed review of DTE Electric's renewable
2 development plans than the instant case.

3

4 **Q20. Do you agree with Witness Woods' recommendation on pages 7-8 of her**
5 **testimony that the Commission impose additional procurement, feasibility**
6 **study, DER, and mitigation plan requirements in this proceeding?**

7 A20. No. Those recommendations would effectively turn this special contract approval
8 case into a resource planning and procurement proceeding. DTE Electric's
9 forthcoming IRP and Amended REP will provide the appropriate forum to assess
10 broader renewable resource needs, RPS compliance, and related planning
11 assumptions. While DTE Electric may evaluate a range of resource and
12 procurement options as appropriate, the Commission should not impose
13 prescriptive procurement requirements in this case that could constrain flexibility
14 or lead to uneconomic outcomes before the relevant resource selection record is
15 established.

16 2. Appropriateness of Historical REC Surplus Trends

17 **Q21. Can you please summarize MNS Witness Woods' testimony regarding DTE**
18 **Electric's REC surplus forecast?**

19 A21. Witness Woods states on page 8 of her direct testimony that DTE Electric's
20 forecasted REC surplus is "not aligned with historical trends". As I understand her
21 position, Witness Woods suggests that because DTE Electric has not historically
22 accumulated REC surpluses of the magnitude reflected in the forecast, the
23 forecasted surplus may not be reasonable.

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1 **Q22. Do you agree that historical REC surplus trends are an appropriate basis for**
2 **evaluating DTE Electric's forecasted REC surplus?**

3 A22. No. Historical REC surplus trends are not particularly relevant to evaluating DTE
4 Electric's forecast because the regulatory and resource planning environment
5 reflected in the forecast is fundamentally different from the historical period on
6 which Witness Woods relies.

7

8 Michigan's RPS remains at 15% through 2029. During this same period, DTE
9 Electric is continuing to develop and bring online material amounts of new
10 renewable generation in preparation for substantially higher renewable energy
11 requirements of 50% in 2030 and 60% in 2035. As a result, developing resources
12 before 2030 positions the Company for the 50% standard, but also creates surplus
13 RECs while the requirement remains at 15%.

14

15 Therefore, historical surpluses are not a useful benchmark. The forecast reflects
16 accelerated build-out ahead of higher future standards, driven by statutory
17 requirements and planned additions, not past REC trends. In effect, Witness Woods
18 criticizes a forecast that reflects prudent planning for higher statutory renewable
19 energy requirements.

20

21 3. Impact of a Calculation Error on RPS Compliance

22 **Q23. Can you summarize MNS Witness Woods' assertions on how a calculation**
23 **error affects RPS compliance?**

24 A23. Witness Woods states on page 35 of her testimony that DTE Electric incorrectly
25 calculated the amount of RECs that may be acquired through market purchases

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1 beginning in 2028. Based on her adjustment, Witness Woods concludes that DTE
2 Electric's forecasted REC position would be reduced relative to the forecast
3 presented by the Company and that DTE Electric could experience a REC shortfall
4 in 2032.

5

6 **Q24. Does MNS Witness Woods' observation regarding the REC market purchase**
7 **calculation affect the conclusions presented in the instant case?**

8 A24. No. ~~The calculation identified by Witness Woods was inherited from the~~
9 ~~Company's Amended REP in Case No. U-21662. For purposes of this proceeding,~~
10 ~~the Company maintained the same forecasting assumptions used in that case in~~
11 ~~order to provide an apples-to-apples comparison of the incremental impacts~~
12 ~~associated with the Customer's enrollment. As a result, the assumption was not~~
13 ~~updated in this proceeding.~~

14

15 While Witness Woods identifies a difference in the calculation, it does not change
16 the purpose of the analysis presented here, which is to evaluate the incremental
17 impact of the Customer's enrollment relative to the Company's currently approved
18 Amended REP assumptions. Moreover, even under Witness Woods' adjusted
19 calculation, the forecasted REC position does not demonstrate noncompliance. The
20 Company's REC compliance position reflects both banked REC surpluses from
21 prior years and planned resource additions. A single-year adjustment to the market
22 purchase assumption does not account for the cumulative REC balance or the
23 additional renewable resources that will be brought online through the VGP Special
24 Contract and IRP processes. The Company expects to update its REC compliance
25 forecast and related assumptions in its upcoming IRP and Amended REP filings,

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1 where those assumptions can be evaluated comprehensively and consistently across
2 the entire forecast horizon.

3

4 **REBUTTAL TO MEICEO WITNESS SHERMAN**

5 *1. Renewable Energy Ownership Proposals*

6 **Q25. MEICEO Witness Sherman argues on pages 9-11 of her testimony that the**
7 **absence of a prescribed ownership split between Company-owned and third-**
8 **party-owned renewable resources creates cost and risk concerns for**
9 **ratepayers. Do you agree?**

10 A25. No. Under the proposed VGP Special Contract negotiated and executed by DTE
11 Electric and the Customer, the Customer is responsible for the full revenue
12 requirement associated with the renewable resources procured to serve its VGP
13 enrollment. Given that the Customer bears these costs in full, a Commission-
14 imposed ownership split is not needed to protect other ratepayers from the
15 renewable resource revenue requirement. As a result, Witness Sherman's concerns
16 regarding ratepayer risk are not applicable.

17 As applied to the proposed VGP Special Contract, the appropriate focus in this
18 proceeding is on whether the procurement framework is tailored to produce
19 resources that are reasonable for the Customer's VGP participation, preserve
20 flexibility, and remain consistent with the Commission-approved VGP special
21 contract framework arising from the settlement agreements in Case Nos. U-
22 20713/U-20851 and U-21172. Consistent with prior VGP special contracts and the
23 VGP Settlement Agreements, the bespoke procurement framework under the
24 Customer's VGP Special Contract was developed collaboratively between DTE

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1 Electric and the Customer and is reasonably tailored to the Customer's specific
2 objectives and requirements.

3

4 **Q26. MEICEO Witness Sherman contends on pages 11-12 of her testimony that**
5 **DTE Electric is required to procure at least 50% of the renewable resources**
6 **serving the VGP Special Contract to come from third-party build-transfer**
7 **agreements ("BTAs"). Is that accurate?**

8 A26. No. Witness Sherman focuses on the Case No. U-21172 settlement provision
9 stating that DTE Electric will *target* the acquisition of a minimum of 50% of the
10 capacity required to fulfill each special contract through build-transfer agreements
11 with third parties. However, that provision cannot be viewed in isolation.

12

13 The Case No. U-21172 settlement recognizes that the outcome of a competitive
14 solicitation cannot be guaranteed. Accordingly, it provides that DTE Electric is only
15 required to issue a BTA RFP and is not required to continue issuing RFPs
16 indefinitely if the solicitation process does not yield contracted projects.
17 Specifically, the Case No. U-21172 settlement states that DTE Electric shall not be
18 required to issue more than one RFP per special contract and shall not be required
19 to continue issuing RFPs if two consecutive build-transfer RFPs fail to produce
20 contracted projects¹.

21

22 The Case No. U-21172 settlement therefore establishes a procurement process, not
23 a mandatory RFP outcome. DTE Electric welcomes viable BTA proposals that
24 satisfy the requirements of the Customer's VGP Special Contract. The Case No. U-

¹ Commission Order Approving Partial Settlement Agreement, Case No. U-21172, July 2, 2024, Section 3.

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1 21172 settlement framework contemplates a meaningful BTA solicitation
2 opportunity, and DTE Electric intends to provide that opportunity consistent with
3 the applicable settlement provisions. DTE Electric has satisfied those requirements
4 for all its prior special contracts and will continue to do so for the Customer's VGP
5 Special Contract. But this proceeding is not the appropriate forum to relitigate VGP
6 Plan settlement provisions that have already been negotiated, approved and
7 implemented.
8

9 **Q27. MEICEO Witness Sherman suggests on pages 14-15 of her testimony that if**
10 **the Customer had enrolled in Rider 17 instead of a customer-requested special**
11 **contract, the IRP settlement ownership split would apply, and that the**
12 **Company has a "capital bias" that leads it to prefer the customer-requested**
13 **offering structure. How do you respond?**

14 A27. The customer-requested offering structure was established in Case Nos. U-
15 20713/U-20851 to provide a customer-specific procurement framework for large
16 customers with unique requirements. The customer-requested offering is not a
17 substitute for Rider 17; it is a distinct offering developed to accommodate the scale
18 and complexity of large-load customer contracts, such as the VGP Special Contract.
19 The Customer's requirements for up to 1,600 MW of renewable energy, procured
20 on an accelerated timeline, is precisely the type of arrangement the customer-
21 requested offering VGP settlement provision was designed to address.
22

23 As to the suggestion that the Company has a "capital bias," the VGP Special
24 Contract is the direct result of negotiated terms and conditions between DTE
25 Electric and the Customer that reflect the bespoke procurement structure required

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1 to serve the Customer's unique and complex needs. Witness Sherman's "capital
2 bias" assertion also ignores the risk and accountability DTE Electric has accepted
3 under the proposed Special Contracts. As confirmed in Company Witness Foley's
4 rebuttal testimony, DTE Electric has accepted customer-protection obligations
5 under the Power Supply Agreement, CCAA, and related agreements, including the
6 position that the Company would not seek to recover from other customers costs
7 that the Commission ultimately determines are in excess of the combined revenues
8 payable to the Company under those agreements. Given that risk allocation, it is
9 reasonable for DTE Electric to maintain sufficient control over the development,
10 procurement, timing, and integration of resources needed to satisfy the Customer-
11 specific VGP Special Contract.

12

13 Third-party suppliers do not assume the same obligations to the Customer, the
14 Commission, or DTE Electric's other customers under the Special Contracts.

15

16 **Q28. MEICEO Witness Sherman claims that third-party-owned renewable**
17 **resources are generally less expensive than Company-owned resources on**
18 **pages 18-20. Do you agree?**

19 A28. No. Witness Sherman relies on outdated and selective comparisons that are not
20 representative of current market conditions². More recent procurement experience
21 indicates that third-party-owned projects are not generally lower cost than
22 Company-owned resources. For example, in DTE Electric's 2024 All-Source
23 Renewable RFP, Company-owned projects averaged approximately \$75 per MWh,
24 while third-party-owned projects averaged approximately \$92 per MWh. These

² Direct Testimony of Dr. Laura S. Sherman, page 20-21; Reference to Consumers Energy 2019 [IRP] competitive solicitation

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1 figures represent the most recent and directly comparable procurement data
2 available to the Company. Witness Sherman's reliance on Consumers Energy's
3 2019 IRP competitive solicitation results is not a reliable basis for concluding that
4 third-party resources are generally less expensive, given that market conditions
5 have changed materially since 2019, including supply chain disruptions, higher
6 interest rates, and changes in federal tax credit structures. Accordingly, mandating
7 higher levels of third-party ownership could increase costs rather than reduce them.
8 While Witness Sherman states that she expects third-party projects to remain less
9 costly, she does not provide current evidence demonstrating that such an outcome
10 is likely under today's market conditions.

11

12 **Q29. MEICEO Witness Sherman suggests on page 15 of her testimony that third-**
13 **party-owned projects can reach commercial operation more quickly than**
14 **Company-owned projects and cites the timeline associated with the VGP**
15 **Special Contract. Is that characterization correct?**

16 A29. No. Witness Sherman mischaracterizes the timeline presented on page 14, line 13
17 of my direct testimony. The timeline identifies the renewable resource quantities
18 needed to maintain compliance by specified years. It does not represent the earliest
19 possible commercial operation dates for those resources, and it does not compare
20 developmental timelines for Company-owned, build-transfer, or third-party owned
21 projects. My testimony states that DTE Electric will acquire or develop the
22 necessary renewable resources *by* those dates. A "by" date is not evidence that
23 Company-owned resources require more time to reach commercial operation than
24 third-party owned resources. Generally, project timing and execution risk are not
25 determined by ownership form alone. A third-party-owned project may be further

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1 along in development in some circumstances, while in other circumstances a
2 Company-developed or build-transfer project may provide greater certainty
3 regarding development control, schedule coordination, integration with the
4 Customer-specific VGP Special Contract, or accountability for completion.
5 Accordingly, the VGP Special Contract timeline does not support Witness
6 Sherman's conclusion that a mandatory third-party ownership requirement would
7 necessarily accelerate commercial operation or reduce risk.

8

9 **Q30. MEICEO Witness Sherman recommends that the Commission require a 50%**
10 **third-party ownership mandate and a 50% Company ownership mandate for**
11 **resources serving the VGP Special Contract. Would such a requirement**
12 **promote competition?**

13 A30. Not necessarily. Witness Sherman's recommendation would mandate a
14 predetermined ownership outcome; it would not simply require a competitive
15 procurement process. Generally speaking, mandating a predetermined ownership
16 split could reduce procurement flexibility and could diminish competitive pressure.
17 By requiring a specific ownership outcome in advance, the Commission would
18 limit DTE Electric's ability to select the most advantageous projects and could
19 inadvertently increase costs.

20

21 The VGP Special Contract framework already includes a competitive component
22 through the solicitation of build-transfer agreement opportunities for the portion of
23 the portfolio subject to that requirement. But imposing an additional 50% third-
24 party ownership mandate would go further by requiring a specific ownership

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1 structure that is inconsistent with the VGP settlement agreements and the terms of
2 the VGP Special Contract.

3

4 That type of mandate could reduce flexibility and may not produce the most cost-
5 effective or timely result for the Customer. Renewable projects differ in cost,
6 development maturity, interconnection status, permitting risk, tax-credit position,
7 commercial terms, and expected commercial operation date. The Company should
8 retain the ability to evaluate those factors within the applicable Commission-
9 approved VGP framework rather than being required to select resources based on
10 a fixed ownership quota that is not appropriate for consideration in this proceeding.

11

12 In addition, the self-build portion of the portfolio serves a different function than
13 third-party ownership. It allows the Company to maintain direct development
14 accountability, schedule control, and integration with the Customer-specific VGP
15 Special Contract obligations. Because the Customer is responsible for the costs of
16 the renewable resources procured under the VGP Special Contract, the question is
17 whether the procurement framework is reasonable and produces resources suited to
18 the Customer's VGP participation, not whether the Commission should replace that
19 framework with a new ownership mandate in this special contract proceeding.

20

21 **Q31. On page 23, MEICEO Witness Sherman relies on paragraph 7 in the**
22 **settlement agreement dated July 2, 2024 approved in Case No. U-21172 to**
23 **assert that, if the Customer's VGP Special Contract is terminated, the**
24 **associated renewable resources would first be allocated to other VGP**
25 **customers and then, if there is insufficient VGP demand, allocated to all**

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1 **ratepayers through the REP or CEP. Does that support her recommendation**
2 **for greater third-party ownership?**

3 A31. No. Witness Sherman's conclusion does not follow from the settlement language
4 she cites. The Case No. U-21172 provision addresses a general cost-recovery
5 allocation framework for terminated VGP special contract capacity and further
6 provides that, if the contract capacity is not needed for VGP, REP, or CEP purposes
7 and termination payments are insufficient, the Company will notify Staff of the
8 actions being taken to mitigate customer impacts. It does not, however, override
9 paragraph 9.1.2 of the settlement agreement entered in Case No. U-20713, which
10 allows the Company and Customer to agree upon bidding procedures applicable to
11 the customer requested projects. Under the CCAA, the Company and Customer
12 have agreed to issue an RFP for 50% of the Customer's requested capacity from
13 build transfer agreements, consistent with paragraph 1 of the U-21172 settlement
14 agreement.

15 Paragraph 7 of the U-21172 settlement agreement referenced by Witness Sherman
16 also does not override the Customer-specific termination-payment, cost-recovery,
17 and credit-support provisions negotiated in the CCAA presented in this case. As
18 Company Witness Foley explains on page 40 of his revised direct testimony, the
19 Customer cannot voluntarily terminate the CCAA, which is the specific scenario
20 covered in the cited Case No. U-21172 settlement provision (e.g., "In the event a
21 Special Contract is terminated by the customer"). Notwithstanding the absence of
22 this threshold settlement provision condition applying to the CCAA, in the event
23 the CCAA is terminated through the Customer's default, the Customer is obligated
24 to pay a termination payment designed to collect the unrecovered portion of each

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1 project's costs over its depreciable life. In other words, the CCAA establishes a
2 termination payment formula designed to be sufficient to recover the unrecovered
3 CCAA project costs if the CCAA were terminated through Customer default.

4
5 Therefore, the future allocation of resource capacity to VGP, REP, or CEP needs
6 contemplated in the Case No. U-21172 settlement provision does not mean that
7 other customers would automatically bear unrecovered costs from the Customer's
8 VGP Special Contract. The CCAA is structured so that the Customer remains
9 responsible for the costs of the renewable resources supporting its VGP Special
10 Contract. If, after the Customer's payment obligations are addressed, a renewable
11 resource provides value for VGP, REP, or CEP purposes, that does not establish
12 that other customers are subsidizing the Customer.

13
14 Importantly, Witness Sherman also does not explain why a third-party ownership
15 mandate would address the risk she wrongly identifies. A third-party ownership
16 mandate would not change the CCAA termination payment obligation or provide
17 more direct protection against the risk suggested by Witness Sherman; the key
18 protection is the Customer's payment obligations under the CCAA, not the
19 ownership form of the renewable resource.

20
21 In sum, Witness Sherman's reliance on the Case No. U-21172 settlement provision
22 is misplaced and does not support her proposal to impose a third-party ownership
23 mandate in this proceeding.

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REBUTTAL TO MEICEO WITNESS SHAVER

1. Annual REC-Based Matching and 24/7 Matching

Q32. MEICEO Witness Shaver questions on pages 8-10 of his testimony whether the Customer can reach a 100% renewable energy objective based on the VGP Special Contract and DTE Electric's RPS compliance. Do you agree with this criticism?

A32. No. Witness Shaver's criticism does not affect the Company's RPS analysis or the reasonableness of the VGP Special Contract. My testimony does not ask the Commission to adjudicate the Customer's voluntary sustainability claims or determine the specific form of renewable energy reporting the Customer may use. Rather, my testimony explains that the Customer elected to support renewable resources through a VGP Special Contract for 40% of its load, and that the associated renewable attributes will be tracked through RECs consistent with the applicable VGP framework.

Witness Shaver's testimony focuses on the difference between annual REC-based matching and hourly or physical matching. That is a different issue from whether the VGP Special Contract is reasonable, whether the Customer is responsible for the costs of the renewable resources, and whether the RECs associated with those resources are properly tracked and not used by DTE Electric for RPS compliance when appropriate. The Commission should evaluate the VGP Special Contract under the applicable statutory and Commission-approved VGP framework, not under a separate 24/7 matching standard.

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1 **REBUTTAL TO GREAT LAKES RENEWABLE ENERGY ASSOCIATION**

2 **WITNESS RICHTER**

3 *1. RPS Compliance Risk Associated with Large-Load and VGP Demand*

4 **Q33. On pages 39–41, GLREA Witness Richter contends that data center load could**
5 **make it more challenging for DTE Electric to meet renewable energy**
6 **requirements. Do you agree?**

7 A33. No. The up to 1,600 MW of renewable energy to be developed under the VGP
8 Special Contract will contribute substantially to the Company's renewable energy
9 portfolio and support its RPS compliance position. These resources are fully funded
10 by the Customer under the VGP Special Contract. The Company's upcoming IRP
11 and Amended REP will thoroughly evaluate RPS compliance, including the effects
12 of large-load customers, and will identify any additional resources needed to
13 maintain compliance. DTE Electric remains committed to meeting its obligations
14 under the RPS statutory framework. Accordingly, the Commission should not adopt
15 Witness Richter's recommendation to issue a warning on future RPS compliance
16 in this special contract proceeding, as such a warning is not warranted and this is
17 not the appropriate forum.

18

19 **Q34. Does this conclude your rebuttal testimony?**

20 A34. Yes, it does.

1 JUDGE STALEY: All right. And then, I
2 know that we have cross for Mr. Bilyeu -- sorry, one
3 moment -- and only MNS has cross, so Mr. Fisk.

4 MR. FISK: Yes. Thank you, your Honor.

5 JUDGE STALEY: All right. Turn it over
6 to you.

7 MR. FISK: Great. Thank you.

8 CROSS-EXAMINATION

9 BY MR. FISK:

10 Q Good afternoon, Mr. Bilyeu.

11 A Good afternoon, Mr. Fisk.

12 Q How are you doing today?

13 A I'm good. How are you?

14 Q Doing all right. Is my audio O.K., you can hear me?

15 A Loud and clear.

16 Q O.K., great. And before we get started, I wanted to make
17 sure that I know you had some issues with the SharePoint,
18 but do you now have access to the SharePoint files?

19 A Yes, I'm in the SharePoint site, files.

20 Q And are you in the MNS folder for, with your name on it?

21 A Yes.

22 Q O.K., great. Great. And then, also, I wanted to just
23 follow up on the correction you made to your rebuttal
24 testimony just to make sure I understand. Is there any
25 change to Exhibit A-2 that needs to be made in connection

1 with this correction?

2 A No.

3 Q O.K. And I'm sorry, could you explain what the
4 correction was?

5 A Yes. So in PA 25, utilities are permitted to purchase 5%
6 of the RECs needed for their RPS target, which would be
7 the target based on that year. Again, the calculation
8 was pointing to the target of the following year; so for
9 example, the 2028 marked purchase REC was pointing to
10 2029, it should have been pointing to 2028, which led to
11 a small change in the amount of RECs.

12 Q O.K. But those are properly reflected in Exhibit A-2?

13 A The calculation I just described is in A-2.

14 Q Yes. O.K.

15 A Yes.

16 Q O.K. And then one other initial question on your direct
17 testimony on page 9, footnote 1.

18 A O.K.

19 Q It says, "Estimate is based on an assumed load factor of
20 88.5%." Is that still accurate, I had thought I had seen
21 that that was corrected to 90%?

22 A Yeah, that was updated to 90%, so the model reflects 90%,
23 which is the correct number, it's just the footnote said
24 88.5.

25 Q So that footnote should say 90?

1 A Yes.

2 Q O.K., great. Thank you. O.K. So I wanted to start off
3 just your, on page 2 of your direct, your work
4 experience. My understanding is that you started in a
5 position with the Renewable Energy Strategy and Special
6 Projects in 2023; is that right?

7 A That's correct.

8 Q O.K. And you say there that part of your
9 responsibilities are planning and executing special
10 projects for renewable energy. What are special
11 projects?

12 A So special projects are ad hoc analyses that may be for
13 various reasons, mostly related to regulatory, policy
14 impacts, various other financial analyses that may be
15 needed to be run.

16 Q O.K. As opposed to kind of like -- why are they special
17 or ad hoc as opposed to just, like are they contrasting
18 with just regular analyses you do every year or
19 something?

20 A That's correct. These requests would not be standard
21 requests that come on a frequent basis, these would be
22 special analyses that we are running for particular
23 purposes.

24 Q O.K. And so when you're talking about special projects,
25 you're talking about projects within the utility, not

1 like special renewable energy projects themselves?

2 A That's correct.

3 Q O.K. And then with your promotion in 2025 to Director,
4 it does say that you have activities related to land
5 acquisition, capital financing, and financial modeling;
6 is that right?

7 A That's correct.

8 Q O.K. And is that with regards to specific projects,
9 renewable energy projects, or what?

10 A Specifically the land acquisition fees would be what the
11 title infers, which is acquiring land for future
12 projects.

13 Q O.K. Do you have any other involvement with individual
14 renewable projects for DTE?

15 A My only other involvement would be regarding the project
16 capital management, which is more of a budget function.

17 Q O.K., great. Thank you. So I wanted to start with, in
18 the SharePoint, Exhibit MEC-10, it's actually an
19 attachment to Dr. Woods' testimony, but I've included it
20 in the SharePoint as your response to MNS-1.13.

21 A O.K.

22 Q Great. And you are the respondent on this, correct?

23 A That's correct.

24 Q O.K. And this asks for the Company to identify the
25 annual renewable energy build plan amounts for three

1 different tranches of renewable energy builds
2 essentially, correct?

3 A That's correct.

4 Q O.K. And so the, so Case U-21662, that is the Amended
5 Renewable Energy Plan; is that right?

6 A That's correct.

7 Q Okay. And that, and the numbers here, the megawatts of
8 renewables per year is still accurate?

9 A From that plan, yes.

10 Q O.K. And that was -- and that plan was developed and
11 approved before the Google Data Center, an issue in this
12 proceeding, was part of the mix, correct?

13 A That's correct.

14 Q O.K. And it was also developed, that Renewable Energy
15 Plan was also developed before the Oracle Data Center in
16 U-21990 was in the mix; is that right?

17 A That's correct.

18 Q O.K. So that's kind of the, the U-21662 is kind of the
19 pre-data center baseline, would that be fair to say?

20 A It's the base case that was used for the subsequent cases
21 that came after.

22 Q For the subsequent case what?

23 A For the subsequent cases that came after, referring to
24 21990 and 22058.

25 Q O.K. And so those subsequent cases are in addition to
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1 the U-21662 builds, correct?

2 A Yes.

3 Q O.K. And then for U-22058, the current proceeding, the
4 numbers there, the 500, 700, and 400 megawatts, that is
5 the 1.6 gigawatts of renewables that's included in the
6 CCAA; is that right?

7 A That's correct.

8 Q O.K. And then in 2033 and 2034, there's negative numbers
9 there; what do those refer to?

10 A Those refer to reductions in the build plan
11 (inaudible) --

12 COURT REPORTER: ...in the build plan?
13 I'm sorry, I didn't get what you said. ...in the build
14 plan?

15 A -- needed to stay in compliance.

16 COURT REPORTER: Thank you.

17 Q (By Mr. Fisk): And those are reductions to the build
18 plan from U-21662?

19 A That's correct.

20 Q O.K. So the thousand in 2033 and 2034 are reduced by the
21 200 and the 50, correct?

22 A Correct.

23 Q O.K. I want to turn then to your Exhibit A-2 to your
24 direct testimony.

25 A O.K.

1 Q And A-2 is where you forecast the amount of RECs,
2 renewable energy credits or RECs that DTE is anticipating
3 accruing under these various renewable build plans; is
4 that right?

5 A That's correct.

6 Q O.K. And that is contrasting, that, those RECs with the
7 amount of RECs that are required under the state
8 Renewable Portfolio Standard, correct?

9 A Yes.

10 Q O.K. And so there's a number of different -- well,
11 there's a few different versions of these over the years,
12 I wanted to -- and many of them cross-reference each
13 other -- I wanted to make sure that I have them clear.
14 First, in this proceeding, you produced a slightly
15 expanded version of Exhibit A-2 in response to CEO
16 request 3.2; is that right?

17 A That's right.

18 Q And that is, if you could go into the SharePoint, that is
19 included -- I want to make sure I have it correct that it
20 is -- now I'm losing the number. Sorry, give me one
21 second. If you could go to MEC-28. Let me know when
22 you're there.

23 A O.K.

24 Q O.K. And so this is the, this is in a response to CEO
25 request 3.2 in which you were the respondent, correct?

1 A That's correct.

2 Q And then on the -- and then attached to it is an updated
3 version of Exhibit A-2 with basically lines 38 through 45
4 added; is that right?

5 A I'm sorry, Mr. Fisk, what was that last sentence?

6 Q It is an updated version of Exhibit A-2 to which you have
7 now added lines 38 through 45; is that right?

8 A That sounds correct. I have to check the exact lines,
9 but -- that's correct.

10 Q O.K. And so -- and this document, the attachment to
11 Exhibit MEC-28, lines 1 through 37 are the same as your
12 Exhibit A-2, correct?

13 A With the addition of the additional lines, yes.

14 Q O.K., great. Thank you. And then this -- let's stick to
15 this Exhibit MEC-28. If you see the column (b) that says
16 Source, and that's a source of various lines in this
17 exhibit; is that correct?

18 A That's correct.

19 Q O.K. And there's a number of references to Exhibit A-2
20 from Case U-21662; is that right?

21 A That's right.

22 Q O.K. And if we could just confirm that that Exhibit A-2
23 has been marked as MEC-29 in the Share file?

24 A That's correct.

25 Q And so the references to U-21662 Exhibit A-2 that are in
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1 MEC-28 come from this document that's been marked MEC-29;
2 is that right?

3 A That appears correct.

4 Q O.K. And then similarly, MEC-28 includes also some
5 references to U-21990 Exhibit A-3; is that right?

6 A Mr. Fisk, are you requesting I go back to the --

7 Q So MEC-28, it references, especially at line 34, Exhibit
8 A-3 to U-21990; is that right?

9 A That's right.

10 Q O.K.

11 JUDGE STALEY: I would like you guys to
12 be careful talking over each other because it makes it a
13 little tough for Ms. Penn. I know you're anticipating
14 each other's answers, but there's already an echo in the
15 room so hearing Mr. Bilyeu is little harder, I think
16 that's why Ms. Penn is trying to decipher what you're
17 saying, there's just a little bit of a, it just makes it
18 a little unclear, so just try real hard not to talk over
19 each other.

20 MR. FISK: O.K. Thank you, your Honor,
21 and my apologies.

22 Q (By Mr. Fisk): The reference to U-21990 Exhibit A-3,
23 that is the document that has been marked as Exhibit
24 MEC-30 in the Share file; is that correct?

25 A That's correct.

1 Q O.K. And you were the witness that created Exhibit A-3;
2 is that right?

3 A That's correct.

4 Q O.K.

5 MR. FISK: All right. I would like to
6 move Exhibits MEC-28, 29, and 30 into the record.

7 JUDGE STALEY: All right. Is there any
8 objection to the admission into the record of Exhibits
9 MEC-28, MEC-29, and MEC-30?

10 Hearing none, those --

11 MR. JANISZEWSKI: Your Honor.

12 JUDGE STALEY: I'm sorry.

13 MR. JANISZEWSKI: Sorry, your Honor. I'm
14 just reviewing MEC-30 a little bit. No objection, your
15 Honor.

16 JUDGE STALEY: All right. Thank you.
17 Hearing no objections, MEC Exhibit -- Exhibit MEC-28,
18 MEC-29, and MEC-30 are admitted to the record.

19 MR. FISK: Great. Thank you, your Honor.

20 Q (By Mr. Fisk): O.K. Mr. Bilyeu, I wanted to walk
21 through MEC-28 a little bit to make sure I understand how
22 you did the RPS compliance calculations. So my
23 understanding, correct me if I'm wrong, of the RPS is
24 essentially the Company has to have renewable energy
25 credits to cover a certain percentage of their retail

1 sales for a particular year, is that right, at a very
2 high level?

3 A That's right. That's fair.

4 Q And that percentage, of course, is 15% through 2029, and
5 then the 50% starting in 2030, and then 60% starting in
6 2035?

7 A That's correct.

8 Q O.K. And so for Exhibit MEC-28, line 4 sets forth those,
9 your projected sales for each year before including any
10 Data Center load; is that right?

11 A That's correct.

12 Q O.K. And then line 5 is the Oracle Data Center; is that
13 right?

14 A Yes.

15 Q And then line 6 is the Google Data Center from this
16 proceeding; is that right?

17 A That's correct.

18 Q O.K. And line 6 has the full, by 2029, has the full load
19 at, assuming the Google Data Center is at the full one
20 gigawatt; is that right?

21 A I'm sorry, Mr. Fisk, did you say line 6 includes the Data
22 Center, the second Data Center of Customer's full load?

23 Q Yes, starting in 2029.

24 A That's correct.

25 Q O.K. And then there's, on line 10 is VGP sales,
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1 incremental VGP sales; is that right?

2 A Which line are you referring to?

3 Q Line 10.

4 A That's correct.

5 Q And VGP is Voluntary Green Pricing; is that right?

6 A Correct.

7 Q And so the way the RPS works is that load that a Customer
8 chooses to engage in VGP purchases for doesn't count
9 towards your RPS compliance; is that right?

10 A Load enrolled in the VGP Program is reduced from the
11 total retail sales from the RPS calculation.

12 Q O.K. And the renewable energy that serves that load does
13 not count towards the, your RECs for complying with that
14 RPS calculation, correct?

15 A RECs generated from the VGP assets are not included
16 within the numerator of that equation.

17 Q The numerator being the amount of RECs you need?

18 A That's correct.

19 Q O.K. And the renewable energy created through the VGP
20 Program also does not count towards the number of RECs
21 you have; is that right?

22 A Can you ask that again, Mr. Fisk?

23 Q The renewable energy generated through the VGP Program
24 does not count towards the number of RECs that DTE has to
25 meet its RPS; is that right?

1 A As stated before, it's not included with that numerator
2 to count towards the RPS.

3 Q O.K. So it's not relevant to, the VGP load is not
4 relevant to whether you need, say, a million RECs in
5 2040, right, as a complete hypothetical?

6 A Can you rephrase the question, I'm not following?

7 Q Let's say you're calculating the amount of RECs you need
8 for the year 2040 and a portion of your load is served
9 through the VGP Program, that load did not count towards
10 the number of RECs you need for 2040, correct?

11 A It reduces the RECs needed for that target that year, so
12 it reduces the target.

13 Q And the renewable energy that is used to create -- to
14 generate -- to serve the VGP customers, the renewable
15 energy used to serve the VGP customers, that renewable
16 energy did not create RECs that would go towards meeting
17 that 2040 amount, correct, like to determine if DTE is in
18 compliance with that 2040 amount; is that right?

19 A We do not retire RECs to count towards RPS compliance
20 that are from the VGP Program.

21 Q O.K. So for the Google Center, Data Center, 40% of its
22 load is in, is -- will be served through the VGP special
23 contracts; is that right?

24 A That's correct.

25 Q O.K. So that 40% is removed in your Exhibit MEC -- in
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1 Exhibit MEC-28, that 40% of the Google load is removed
2 from calculating the number of RECs that DTE needs; is
3 that right?

4 A It's reduced -- it's removed from the Company's sales
5 which therefore reduces the RECs needed for the RPS
6 targets.

7 Q O.K. And then the remaining 60% of Google's load would
8 be part of the calculation of the amount of RECs that DTE
9 needs to achieve RPS compliance, correct?

10 A It would be factored into the RPS calculation, that's
11 correct.

12 Q O.K. So for that remaining 60% of the load, starting in
13 2030, DTE would need to have enough RECs to cover 50% of
14 that Google non-VGP load, correct?

15 A Correct.

16 Q O.K. And for 2035 and beyond, DTE would need to acquire
17 enough RECs to cover 60% of Google's non-VGP load, right?

18 A That's correct.

19 Q O.K. But DTE would not need to get enough RECs to cover
20 all of Goggle's non-VGP load, correct?

21 A 60%.

22 Q O.K. And then so lines 22 to 24 of Exhibit MEC-28 has
23 energy credits obtained through various means, correct?

24 A That's correct.

25 Q O.K. And the three different categories here are all

1 from U-21662; is that right?

2 A Correct, other than as stated in my correction to my
3 rebuttal, the error that's in line 24.

4 Q Right. O.K. And with regards to line 22, which is
5 generation or BOT, when DTE acquires a new renewable
6 resource, how does this affect the generation, like what
7 assumptions are you using around, let's say, you know,
8 the solar that's being added in 2028, how much of that --
9 how much generation is that assumed to provide?

10 A Specifically for this Customer?

11 Q Well, for this analysis in Exhibit MEC-28.

12 A So as stated in my direct testimony, the generation
13 associated and needed for this customer was based on
14 solar assumptions with a 22.5% net capacity factor, you
15 know, applied to an 87 (inaudible) --

16 COURT REPORTER: ...applied to an 87?

17 THE WITNESS: Sorry, Lori. 8760.

18 COURT REPORTER: Complete your answer.

19 A -- to account for hourly generation.

20 Q (By Mr. Fisk): And are those the same assumptions you
21 used in developing these numbers in U-21662?

22 A There are a lot of various different assumptions, a lot
23 of different projects, various assumptions, could be
24 wind, could be solar, they vary.

25 Q O.K. So the numbers, the generation numbers in line 22

1 of MEC-28 could be based on somewhat different
2 assumptions than the ones used in this proceeding for the
3 amount of RECs that a renewable generator would create?

4 A Yes. It was based on the build plan from the Amended REP
5 in Case No. 21662, which included various projects of
6 different sizes and assumptions, whereas the additional
7 build needed for the compliance aspect of this Customer
8 included the solar assumptions I just discussed.

9 Q O.K. But none of the, none of the solar being acquired
10 or built for the Google customer is reflected in line 22,
11 correct?

12 A That's correct.

13 Q O.K. And then looking at line 29, you have energy credit
14 ending balance; do you see that?

15 A That's correct, yeah, I see it.

16 Q O.K. And that is the number of, am I correct, that's the
17 number of RECs that the Company has at the end of the
18 year after they've utilized the number of RECs they need
19 to ensure RPS compliance?

20 A With the Google load factored in, yes.

21 Q O.K. And if that, if the number for a year in line 29 is
22 positive, is that a REC surplus?

23 A That's correct.

24 Q O.K. And that REC surplus can then be carried over to
25 the next year; is that right?

1 A Correct.

2 Q O.K. And then if the REC number -- I'm sorry. If the
3 number in line 29 for a particular year is negative,
4 that, is it fair to call that a REC deficit?

5 A Correct.

6 Q O.K. And so there are three different energy credit
7 ending balances in Exhibit MEC-28, one's in line 29,
8 one's in line 32, and one is in line 45; is that right?

9 A That's correct.

10 Q O.K. And line 32, am I right, is the REC balance in a
11 scenario with only the Amended REP renewables build and
12 without either the Google or Oracle Data Centers?

13 A That's correct.

14 Q And that scenario shows surpluses of 15 million or more
15 RECs in every year from 2029 through the end of the
16 analysis; is that right?

17 A Yes.

18 Q O.K. And then line 29, energy credit ending balance,
19 shows the balance with only the Amended Renewable Energy
20 Plan build, but with both Google and Oracle Data Centers;
21 is that right?

22 A Would you mind stating that again, Mr. Fisk?

23 Q Line 29 reflects the ending REC balance for a scenario in
24 which only the Amended REP renewable builds have
25 occurred, but both the Google and Oracle Data Centers

1 come online; is that right?

2 A That's correct.

3 Q O.K. And that scenario shows a deficit starting in 2031
4 running through 2041; correct?

5 A Correct.

6 Q O.K. And then finally, line 45 is an energy credit
7 ending balance for the scenario in which both the Google
8 and Oracle Data Centers come online and all of the
9 renewable energy build shown in MEC Exhibit 10 that we
10 discussed earlier occurs; is that right?

11 A Correct.

12 Q O.K. And the RECs generated by that renewable energy
13 build from MEC-10 are reflected in line 38; is that
14 right?

15 A That's correct.

16 Q O.K. And does line 38 reflect any RECs from the 1.6
17 gigawatts of renewables for the Google Data Center that's
18 included in the CCAA?

19 A It is in regards to line 43 where it reduces the
20 compliance requirement.

21 Q Line 43. So that is a reduction to the amount of, the
22 increase in the number of RECs that would be needed from
23 the addition of the Google Data Center, right?

24 A That reflects their, the Customer's enrollment in the VGP
25 Program which reduces the denominator of the RPS

1 calculation.

2 Q So, I mean it -- well, inclusion of 40% of the Google
3 Data Center load in the VGP Program reduces the extent to
4 which adding Google increases your REC requirements,
5 correct?

6 A That's correct.

7 Q O.K. And line 38 which talks about the amount of RECs
8 that you are generating does not include any RECs from
9 the 1.6 gigawatts of renewables under the CCAA, correct?

10 A That's correct.

11 Q So line 38, the only additional renewable generation --
12 strike that.

13 Line 38, it says that the source is
14 U-21662 Exhibit A-4 plus Workpaper 4 modified for
15 additional megawatts, correct?

16 A Correct.

17 Q And the additional megawatts referenced there is only the
18 1.8 gigawatts of renewables assumed for the Oracle Data
19 Center, correct?

20 A Correct.

21 Q So the primary difference between the REC deficit shown
22 in line 29 and the surpluses shown in line 45 is the
23 additional RECs -- the additional 1.8 gigawatt of
24 renewables assumed for Oracle, correct?

25 A That's correct.

1 Q O.K. So to the extent that the renewable build in 2033
2 and '34 can be reduced due to the sufficiency of RECs,
3 isn't that due to the 1.8 gigawatt renewable assumption
4 for Oracle?

5 A Would you mind asking that again?

6 Q So -- well, let me take a step back. I believe your
7 earlier testimony was that Exhibit MEC-10 shows that
8 there can be a reduction in the renewable energy build of
9 200 megawatts in 2033 and 50 megawatts in 2034, correct?

10 A That's right.

11 Q And that's because your Exhibit A-2 was showing in line
12 45 a surplus of RECs for which you don't -- you wouldn't
13 need the 200 megawatts additional build in 2033 and
14 50 megawatts in 2034 to ensure continued compliance,
15 right?

16 A Yes. We maintain a surplus of RECs.

17 Q O.K. And the reason why you have a surplus of RECs in
18 line 45 when you don't have it in line 29 is because of
19 the 1.8 gigawatts of renewables assumed for Oracle,
20 correct?

21 A I'd say it's because of a multitude of factors, including
22 the reduction of the target and the REC surplus that is
23 available.

24 Q And the REC surplus that's available is because of the
25 assumption that there's going to be 1.8 gigawatts of

1 renewables for Oracle, right?

2 A That's one factor, but a REC surplus is there just
3 because there's more generation (inaudible) --

4 COURT REPORTER: I'm sorry. Please
5 repeat that slower.

6 A The reason a REC surplus is there is because there's more
7 generation than what is needed for the REC compliance
8 target.

9 Q (By Mr. Fisk): Right. And that generation is for the
10 renewables for Oracle and the renewables included in the
11 Amended REP, correct?

12 A That's correct.

13 Q And not the renewables in the CCAA, correct?

14 A It's a factor, it's a reduction to the target, so it
15 plays a factor.

16 Q Well, Google increases the target, it's just the 40% of
17 Google being served in VGP means the increase of adding
18 Google is less than it would have been with 100%,
19 correct?

20 A Right, it's a factor.

21 Q But it's not a factor leading to a -- the addition of
22 Google itself is not causing a surplus of RECs, correct?

23 A Can you specify the question?

24 Q The addition of the Google Data Center to DTE's system is
25 not causing a surplus of RECs, correct?

1 A It is requiring an increase in the RECs needed for the
2 RPS target.

3 Q It is? You said it is?

4 A It is.

5 Q Yes. O.K. Thank you.

6 MR. FISK: Your Honor, I'm at a breaking
7 point, I know you like to take a break every like hour,
8 hour and a half, so if we'd like to take break, I'm happy
9 to continue, but if you'd like to take a break, that
10 works, too.

11 JUDGE STALEY: Lori, would you like to
12 take a quick break?

13 COURT REPORTER: Sure.

14 MR. FISK: O.K.

15 JUDGE STALEY: We are off the record, and
16 we'll take a ten-minute break.

17 MR. FISK: Thank you.

18 MR. JANISZEWSKI: Thank you.

19 JUDGE STALEY: Thank you.

20 (Recess from 2:22 p.m. until 2:32 p.m.)

21 JUDGE STALEY: O.K. We are back on the
22 record in Case No. U-22058, continuing with Mr. Fisk's
23 cross-examination. Mr. Fisk.

24 MR. FISK: Great. Thank you, your Honor.

25 Q (By Mr. Fisk): O.K. Mr. Bilyeu, just if you could turn
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1 to Exhibit MEC-30, which is your, it's your Exhibit A-3
2 from U-21990.

3 A O.K.

4 Q And also if you could pull up your Exhibit MEC-31, which
5 is your testimony accompanying Exhibit A-3 from U-21990.
6 Let me know when you're there.

7 A To clarify, you said MEC-33?

8 Q 31. Sorry.

9 A 31. O.K.

10 Q O.K. And if you turn to page 9 of your testimony in
11 Exhibit MEC-31.

12 A O.K.

13 Q You have a discussion there starting on line 11 about,
14 for the Oracle Data Center, if the Company were to use
15 its REC bank to the maximum extent, you would need
16 443 megawatts of additional renewable energy capacity to
17 ensure RPS compliance; is that right?

18 A Yes, if the Company used the entire REC bank, that would
19 be what would be needed for compliance for Oracle.

20 Q O.K. So, and then it says in line 18, it says refer to
21 Exhibit A-3, line 31, for the updated REC balance
22 including the additional 443 megawatts; do you see that?

23 A Yes.

24 Q O.K. And if you go back to Exhibit MEC-30, which is the
25 Exhibit A-3 referenced there, there is no line 31. Is

1 that correct?

2 A That appears correct.

3 Q O.K. Do you know how -- if somebody wanted to create
4 line 31 essentially using the 443 megawatts, what -- how
5 would you calculate the number of RECs that you would
6 assume from that 443 megawatts per year?

7 MR. JANISZEWSKI: Your Honor, given a
8 little bit of leeway on the questioning regarding Case
9 U-21990, I do want to place an objection. I mean
10 Mr. Fisk is litigating, asking questions regarding the
11 substance of exhibits from an entirely different case
12 without a foundation as to how it specifically relates to
13 the issues in this case regarding the reasonableness and
14 prudence of the special contracts for an entirely
15 different customer in this case.

16 MR. FISK: If I may your Honor, this is
17 in Exhibit MEC-30 that's already been admitted into the
18 record. It is relevant because it is cited in Exhibit
19 A-2 in this current proceeding as part of the analysis
20 that Mr. Bilyeu did to demonstrate in this proceeding
21 that RPS compliance would be achieved, and it's, and I
22 think the specific question is relevant because the
23 assumption around the amount of renewables that would be
24 built for the Oracle Data Center that feeds into Exhibit
25 A-2 has changed from 443 megawatts in the Oracle

1 proceeding to 1.8 gigawatts in this proceeding, and I'm
2 trying to get a sense of the, how many RECs are created
3 by that change, that changed assumption.

4 JUDGE STALEY: O.K. I, in some ways I
5 agree with Mr. Janiszewski, I don't want us to be going
6 back in and relitigating 21990, particularly since I
7 believe MEC has appealed the order coming out of that and
8 I don't want that to turn into something here. O.K.

9 MR. FISK: Perfect.

10 JUDGE STALEY: I'll give you a little
11 latitude, I'd like you maybe to develop, you know, your
12 direction a little more quickly rather than feeling like
13 we're spinning our wheels in 21990.

14 MR. FISK: O.K. Appreciate that, your
15 Honor.

16 JUDGE STALEY: O.K.

17 MR. FISK: O.K.

18 Q (By Mr. Fisk): So I guess to rephrase the question, I'm
19 trying to figure out how, how would you calculate the
20 number of RECs that the 443 megawatts of renewables
21 assumed in 21990 would create for purposes of your RPS
22 compliance analysis?

23 A So first off, that was a scenario (inaudible) --

24 COURT REPORTER: ...that was a scenario,
25 word after that?

1 A -- that was ran for that case for the 443 megawatts,
2 which was a scenario where we used the entire REC bank in
3 that scenario. Calculating the REC generation from that
4 without digging back into that case, it would be you take
5 your technology assumption, the net capacity factor times
6 your 8,760 would give you your REC generation.

7 Q (By Mr. Fisk): And do you know, were those assumptions
8 that you used in that case the same as the assumption you
9 used for determining how many RECs in the Google
10 proceeding the 1.8 gigawatts of renewables assumed for
11 Oracle would create?

12 A I can't say with 100% certainty.

13 Q Would they be approximately the same, I mean?

14 A Both cases use solar technology as the assumption, so
15 they should be approximately close.

16 Q O.K. So if you -- and obviously both cases would use
17 8,760 hours, correct?

18 A Correct.

19 Q O.K. So that an amount of RECs generated by the 1.8
20 gigawatts of renewables assumed in the Google proceeding
21 would be somewhere around four times as many as the RECs
22 that would be assumed for the 443 megawatts of renewables
23 assumed in 21990?

24 A As compared to that scenario, there would be more RECs in
25 this case which use a reasonable mid point of the

1 assumptions in 21990.

2 Q And the more RECs in this case would be about four times
3 as many as the RECs in the previous case, correct?

4 A Just to clarify, Mr. Fisk, in the affordability analysis
5 for that case, we used 1,800 megawatts, not 440. My
6 exhibit represents a scenario there where we used the
7 entire REC bank. So just to clarify, like when we say
8 what was used, they were both used.

9 Q Understood. But what was used for the version of Exhibit
10 A-3 in U-21990, which is the equivalent of Exhibit A-2 or
11 the same type of analysis as Exhibit A-2, I'm just trying
12 to compare the number of RECs assumed in Exhibit A-3 in
13 U-21990 to the number of RECs assumed in the very similar
14 type of analysis done in this Google proceeding.

15 A The RECs in A-3 are less than the RECs in the similar
16 exhibit in this proceeding.

17 Q O.K. But you don't know if it's four times, one-fourth
18 the number?

19 A I don't have the exact amount or calculation in my head.

20 Q O.K. If we could switch gears to, if you could open up
21 Exhibit MEC-24 in the SharePoint, and let me know when
22 you're there.

23 A I'm there.

24 Q O.K. And this is a response to MNSDE-2.14a; is that
25 right?

1 A Correct.

2 Q And you are the respondent; is that right?

3 A Correct.

4 Q O.K. So the question here is about, it asks to identify
5 in megawatts the amount of renewable energy projects not
6 covered by the CCAA that the Company projects will be
7 needed to be deployed to meet the Company's RPS
8 obligations. Is that a fair reading of the question?

9 A Yes.

10 Q O.K. And the last line of your answer is: There are no
11 incremental renewable energy projects not covered by the
12 CCAA identified for RPS compliance that would be
13 attributable to the Customer's load; is that right?

14 A Correct.

15 Q And were you listening in to the cross of Mr. Foley
16 earlier today?

17 A I did not listen to the entire cross.

18 Q O.K. Do you recall there was a, or maybe you know or
19 not, that there was a discussion about what level of
20 incremental renewable energy costs might be incorporated
21 into the affordability analysis, were you there for that
22 part of the discussion?

23 A I was there for a portion of the conversation about the
24 affordability analysis.

25 Q O.K. So, and did you -- is it your understanding that

1 the affordability analysis would reflect if there were
2 incremental renewable energy costs incurred to serve the
3 Google Data Center that were not covered by the CCAA,
4 those would be reflected in the affordability analysis?

5 A I'm sorry, Mr. Fisk, I missed the first portion of that
6 question.

7 Q Is it your understanding that if there were incremental
8 renewable energy costs to serve the Google Data Center
9 that were not covered by the CCAA, those would be
10 reflected in the affordability analysis?

11 A Is the question like a hypothetical, if that were to
12 happen within it, or are we saying that is there any
13 incremental --

14 Q Hypothetical, if there is.

15 A I don't know, I'm not the affordability witness, I don't
16 know if I could respond to that.

17 Q O.K. Fair. Do I take it from your response to Exhibit
18 MEC-24 that there are not any incremental renewable
19 energy costs to serving the Google Data Center, in your
20 opinion?

21 A That's correct.

22 Q And would the Company be using banked RECs to serve the
23 Google Data Center?

24 A It would be using a surplus of RECs, a portion of it this
25 Customer would be paying for.

1 Q And how would this Customer be paying for the surplus
2 RECs?

3 A The Customer is paying for 100% of their load as part of
4 the PSCR which will pay for the RECs generated in the RPS
5 program, so they are contributing to the REC surplus.

6 Q So that would be RECs generated after the Customer starts
7 paying, correct?

8 A No. As soon as their load comes online, they pay for all
9 existing assets and all future assets as part of their
10 PSCR cost.

11 Q So if they were -- if there are RECs, surplus RECs that
12 were created before Google comes online and starts paying
13 that are used to serve Google, would that not be an
14 incremental cost to serve Google?

15 A So a few things. There's our REC bank is only months
16 old, it's not years old. You know, when I say that, we
17 always retire the oldest REC first, so the REC bank is
18 not made up of I'll say a large surplus of previous years
19 paid for by other customers, it is recent RECs developed
20 within the last six months or so that the Customer will
21 be contributing to, and because they paid through the
22 PSCR, they will have access to that REC bank just like
23 any other customer coming online with DTE.

24 Q And you anticipate that -- strike that.

25 RECs can be used for up to five years,
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1 correct?

2 A They retire if not used.

3 Q After five years?

4 A After five years.

5 Q O.K. So in the event that you started using older RECs
6 than the six months you've cited, there could be an
7 incremental cost, correct?

8 A Well, the RECs are already -- there's no incremental cost
9 associated with the use of banked RECs since the RECs are
10 already paid for through the PSCR, which Google is,
11 again, paying 100% of load associated with the PSCR.

12 Q So there is no scenario in which DTE would be using
13 REC -- would be using banked RECs that were created
14 before Google started paying in order to serve Google?

15 A If you -- as displayed in my Exhibit A-2, there could be
16 a small overlap, a very small portion of RECs, but it
17 would be very minimal.

18 Q And would that small portion be an incremental cost?

19 A No, it would not.

20 Q Why not?

21 A Because those -- there's no cost to use those RECs. The
22 alternative is we don't use the RECs and they expire and
23 they're not used. The RECs are paid for at the time of
24 generation, not when the banked RECs are used for
25 compliance.

1 Q So somebody paid for the generation of those RECs
2 already, somebody besides Google?

3 A RECs were created and paid for through the PSCR, which,
4 again, all customers have access to, the same as a
5 residential customer that comes online would have access
6 to that REC bank the same as Google who is paying the
7 PSCR.

8 Q O.K. But the small portion of RECs that were created
9 before Google came online that could be used to serve
10 Google would have been paid for by someone else, correct?

11 A If there was a small portion, it's possible that those
12 RECs could have been paid for by other customers before
13 their load came on, but again, it would be a very small
14 amount.

15 Q And I believe we talked earlier that Google's non-VGP
16 load does increase the number of RECs you need to
17 generate, correct?

18 A It increases the number of RECs generated, however, their
19 load enrolled into the migrant -- I'm sorry -- Voluntary
20 Green Pricing Program effectively means they're paying
21 for 140 percent of renewables, which is again a great
22 benefit to our customers that they're paying for 100% of
23 the load through PSCR plus also reducing the RPS target
24 for our customers by their enrollment in the VGP Program.

25 Q They're minimize -- they're reducing the increase?

1 A But they're also paying propor -- the PSCR works by they
2 pay proportionally to their load, so to the extent that
3 their load causes an RPS increase, that increase would be
4 correlated to their load, so, therefore, they're paying
5 proportionally through the PSCR and at the same time
6 reducing the target for their other customers through
7 their subscription to the VGP Program.

8 Q So for the increase in the RECs that need to be generated
9 to serve the 60% of the non-VGP Google load, you are not
10 currently projecting they will need to build any
11 additional renewable energy projects; is that right?

12 A To clarify, you said for the non-enrolled portion?

13 Q Yes.

14 A That is correct.

15 Q O.K. If you did need to build additional generation to
16 serve that non-VGP load from Google, would that be an
17 incremental cost that would be reflected in the
18 affordability analysis?

19 A I hate to say with certainty because I'm not the
20 affordability analysis, or witness -- sorry -- so I don't
21 know how that would be reflected in the affordability
22 analysis.

23 Q Would you consider that an incremental cost if you did
24 need to build additional renewable generation to serve
25 the non-VGP Google load?

1 MR. JANISZEWSKI: Your Honor, I do want
2 to clarify that Mr. Bilyeu has asked -- has answered this
3 question twice as it applies to the affordability
4 analysis and not being fully comfortable answering that
5 question. To the extent Mr. Fisk is now talking
6 generically about incremental cost, I guess I don't
7 necessarily want to object asked and answered because it
8 is a different question, but I do want to highlight
9 Mr. Bilyeu has answered the question twice regarding this
10 incremental cost question in the affordability analysis.

11 MR. FISK: So this question isn't asking
12 specifically about the affordability analysis, it's just
13 asking if there was additional renewables that had to be
14 built, would that be an incremental cost, which goes
15 directly to Mr. Bilyeu's response to MEC-24, which is he
16 said no incremental renewable energy projects not covered
17 by the CCAA are needed; so my question is, if there were
18 projects that need FOB built, would those be an
19 incremental cost?

20 JUDGE STALEY: I'm going to overrule that
21 objection. Mr. Bilyeu, you can answer to the extent, you
22 know, that Mr. Fisk is asking that nature of question,
23 and it is understood that you have -- you have repeatedly
24 said that are you not comfortable with the affordability
25 analysis piece of this, but if he's asking just about

1 RECs, I think you can answer that.

2 THE WITNESS: Thank you, your Honor.

3 A The thing that makes this question challenging is that it
4 depends on the circumstances, like what is causing the
5 deficiency in the RECs; is it an industry, is it a market
6 thing that would apply to everything, and why isn't there
7 a surplus of RECs, or why would there be incremental need
8 is important in this question, that's why I'm struggling
9 with it because the why matters here.

10 Q (By Mr. Fisk): So it's -- so in your -- all right. Are
11 you saying that it's incremental only if it's solely due
12 to the Google load, non-VGP load?

13 A Can you phrase that again?

14 Q Are you saying that it, an additional renewable project
15 would be incremental with regards to Google only if the
16 sole reason it was being built was to, because it was
17 necessary to serve the non-VGP Google load?

18 A I'm saying the why would there not be -- why would there
19 be incremental need as compared to the plan to be laid
20 out matters in the response to this question.

21 Q And how do you distinguish if something is an incremental
22 result of the Google load -- when you're looking at the
23 why, what would qualify it as incremental versus not?

24 A Right. So again, there's a lot of factors. Timing
25 matters a lot in the builds, right. So for example, if

1 we were to accelerate some of the Google build, which is
2 allowed under the contract given that it is flexible in
3 terms of when (inaudible) --

4 COURT REPORTER: I'm sorry. ...in terms
5 of when?

6 A -- when projects need to come online, the earlier you can
7 build them, the more of those projects we contribute to a
8 REC surplus by needing less RECs because it reduces the
9 denominator. I mean to the extent in a very like
10 isolated scenario, all things -- or all other things
11 equal, incremental build wouldn't include incremental
12 costs.

13 Q O.K. All right. If you go back to Exhibit MEC-10, which
14 was the different renewable energy builds -- and let me
15 know when you're there.

16 A O.K.

17 Q O.K. Given that the builds for U-22058 and 21990 are in
18 addition to the Amended REP build, would you agree that
19 it's a pretty significant increase in the amount of
20 renewable energy that DTE is looking to bring online in
21 the next six years?

22 A Yes.

23 Q O.K. And before deciding that -- before deciding to
24 propose this level of, this level of builds reflected in
25 Exhibit MEC-10, what analyses did DTE do to determine if

1 these builds are feasible?

2 A Would you be able to help me define analysis, Mr. Fisk?

3 Q You know, a study, assessment of the market, you know,
4 assessment of DTE's capabilities to bring things online
5 at this level, generation online as quickly, I mean it
6 could be a wide array things, but I'm just trying to get
7 a sense of what you all did before signing on to this
8 path.

9 A So the Company did not conduct any kind of analysis or
10 studies, however, it has confidence in its development
11 pipeline that it can complete this build.

12 Q I'm sorry, you said you did not do any sort of an
13 analysis?

14 A We didn't run an analysis that looked at individual
15 projects that would serve this because we have a robust
16 development pipeline that can meet this need.

17 Q So your pipeline on its own can meet this need, your
18 current pipeline?

19 A We are confident.

20 Q That you have enough projects in your current pipeline to
21 meet this need?

22 A Yes.

23 Q O.K. And what -- when you say pipe, projects in a
24 pipeline, what does that mean, like what qualifies
25 something to be in the pipeline rather than not?

1 A Projects in the pipeline could be early stage projects
2 where we are acquiring the land and identifying the
3 (inaudible) --

4 COURT REPORTER: ...identifying the? I'm
5 sorry. ...identifying the something used?

6 A To rephrase, the Company has projects in its late stage
7 development pipeline that are further along that are
8 identifying permitting pathways that are again in
9 development, and then there is potential opportunities
10 that we track as well, that's all on top of potential
11 acquisitions, build transfer agreements, development
12 transfer agreements, PPAs, there is a robust pipeline
13 there of various options to meet this build.

14 Q (By Mr. Fisk): And when you say this build, everything
15 identified in MEC-10?

16 A That is correct.

17 Q O.K. Are you aware of the Annual Reports that DTE filed
18 in its IRP docket?

19 A I'm aware the Company files Annual Reports, I'm not
20 familiar with the reports.

21 Q O.K. Do you -- have you -- do you know that that
22 includes a section on achieving the renewable energy
23 builds reflected -- or included in that IRP?

24 A That sounds correct.

25 Q O.K. And would that be information that would come from
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1 you as the Director of, you know, I don't remember the
2 exact title, but Renewable Energy Special Projects I
3 believe?

4 A I'm sure the Integrated Resource Planning team reaches
5 out for this data from my team.

6 Q O.K. And if you could look at exhibits, what's been
7 marked in the Share file as Exhibits MEC-32 and 33, and
8 why don't we start with 32.

9 A O.K.

10 Q And this is the Annual Report, the 2024 Annual Report
11 from DTE's IRP; is that right?

12 A That's correct.

13 Q O.K. And have you ever seen this document before?

14 A I can't say whether I -- I don't recall if I've seen this
15 document before.

16 Q O.K. So if you turn to page 4 of the report, there's a
17 section called Procured Capacity Report.

18 A I'm there.

19 Q O.K. And Table 1 at the bottom of that page talks about
20 the Target Renewables Build and Capacity Allocation; do
21 you see that?

22 A Yes.

23 Q And do these numbers look familiar to you as levels of
24 renewable builds and acquisitions provided for in the
25 IRP?

1 A Yes.

2 Q O.K. And the, on the next page there's a discussion and
3 a Table 3 that talks about the IRP shortfall; do you see
4 that?

5 A I do.

6 Q O.K. And that, of the 600 megawatts targeted for 2026,
7 the total unfilled capacity, there was a total unfilled
8 capacity of 212 megawatts; is that right?

9 A Correct.

10 Q O.K. So that the Company fell short of the target in
11 that year, for that year?

12 A From the 2023 RFP.

13 Q And then if you look at Exhibit MEC-33, which is the 2025
14 Report.

15 A O.K.

16 Q And starting on page, bottom of page 4 again, Procured
17 Capacity Report, Section II; do you see that?

18 A I do.

19 MR. JANISZEWSKI: Your Honor, I would
20 object just to a lack of foundation. I would feel most
21 comfortable if Mr. Fisk asks Mr. Bilyeu, similar to the
22 2024 Report, whether he's familiar with this document.

23 MR. FISK: Yes, my apologies. I will do
24 so.

25 Q (By Mr. Fisk): Have you seen this document before, the
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1 2025 IRP Report?

2 A I don't recall.

3 Q O.K. Are you generally familiar with the information
4 included here regarding the Renewables Build and Capacity
5 Allocations from the IRP that is shown starting on page
6 4?

7 A Yes.

8 Q Yes?

9 A Yes.

10 Q O.K. Thank you. And so, again, on page 6 of the report,
11 there is a Table 3 that talks about the 2027 Renewables
12 Capacity Summary and it shows an unfilled capacity of
13 213 megawatts; is that right?

14 A That is correct.

15 Q O.K. So I guess I'm just curious, given, you know, these
16 shortfalls here in 2026 and 2027 renewable builds
17 compared to what was in the IRP, what steps are being
18 taken to ensure that the significantly higher build being
19 projected in this proceeding can be met?

20 A So what gives me confidence is understanding what was
21 going on in Michigan in this timeframe. So if we think
22 about the 2023 RFP legislation had just been passed
23 increasing the utility targets from roughly 12% to 15% up
24 to the targets we have now which is 50 and 60, Michigan
25 needed time to develop projects so that they could bid

1 into these RFPs. Same thing with 2024, this is now I
2 think of the legislation actually went into effect in
3 2024, again, it takes time to develop these projects, so
4 it's very common you're going to see a shortfall in the
5 early RFPs now that lead into the 2025 RFP where now we
6 are a thousand megawatts over what our request was,
7 indicating that the, kind of the Michigan market is
8 catching up.

9 Q O.K. So is the latest RFP you just referenced, is that
10 for the 2028 build that's reflected in this, in Exhibit
11 MEC-33 on page 5?

12 A That's correct.

13 Q O.K. And you all are on target to meet that full build
14 that's shown on Table 1?

15 A Excuse me, there's a discovery response with the exact
16 number. So I will clarify, I do not run the
17 (inaudible) --

18 COURT REPORTER: I do not run the?

19 A Sorry, Lori. -- the Competitive Procurement Group, but
20 yes, we, right now we are, have shortlisted 2,350
21 megawatts compared to our request of 1,350 megawatts, and
22 that 1,350 megawatts included the shortfalls from the
23 previous year rolled over into that request.

24 Q (By Mr. Fisk): And shortlisted means what?

25 A The team is currently talking with the developers.

1 Q O.K. So you're confident that the 2,350 that are
2 shortlisted will turn into at least enough actual
3 projects to meet the 2028 build?

4 A I would state that there is enough projects that are
5 conforming to our RFP requirements and that have moved on
6 to discussions with the developers, so the projects are
7 conforming, meaning they have to meet quite a few
8 thresholds to get to that point to build confidence that
9 we are ready to have conversations.

10 Q So you've cleared though thresholds to build the
11 confidence or you're still clearing them?

12 A If they're shortlisted, they've met those requirements,
13 so now it's discussions with the developers.

14 Q O.K. And you're confident that those discussions will
15 lead to at least the 1,350 megawatts of actual projects?

16 A Optimistic.

17 Q O.K. Have you taken any steps given the results of the
18 previous two years, the '23 and '24 RFPs that fell short
19 of the goal to ensure that the much higher goals moving
20 forward are achieved?

21 A Was the question whether we took learnings from those two
22 years and carried them forward? I'm sorry.

23 Q Learnings, changes to how you approach renewable
24 procurement, anything you've done to increase the
25 confidence that you'll be able to achieve the much higher

1 targets moving forward?

2 A So again, just to clarify, I don't run the Competitive
3 Procurement Group, but I do know that after every RFP, we
4 sit down to understand areas where we can improve.

5 Q O.K. And to your knowledge, were areas identified and
6 changed?

7 A I don't know what specific areas were identified.

8 Q Who runs that group?

9 A Louisa Dunlap.

10 MR. FISK: O.K. I'd like to move
11 Exhibits MEC-32 and 33 into record.

12 JUDGE STALEY: Any objection --

13 MR. JANISZEWSKI: Your Honor --

14 JUDGE STALEY: -- to the -- I'm sorry.

15 MR. JANISZEWSKI: Sorry, your Honor.

16 Yeah, the Company would object to the admission of MEC-32
17 and 33. Mr. Bilyeu indicated he was not familiar with
18 the documents, and he certainly did not prepare the IRP
19 Reports, didn't recall the extent to which he had
20 previously reviewed them, if at all. To the extent he
21 was generally familiar with some of the procurement
22 discussions in the reports themselves, he testified to
23 that in this record. The IRP Reports are public filings,
24 MNS could refer to them I suppose just in terms of their
25 public nature in the U-21139 docket if they would like,

1 but I also would like to emphasize much of this
2 discussion, although the Company remains highly confident
3 in its development pipeline, a lot of this discussion is
4 spilling into planning and procurement issues that are
5 not relevant to the issues up for decision in the special
6 contract proceeding, and the Company is -- has a
7 forthcoming IRP and a forthcoming Amended IRP where these
8 issues will be addressed in detail.

9 JUDGE STALEY: Mr. Fisk, your response.

10 MR. FISK: Thank you, your Honor. You
11 know, Mr. Bilyeu did testify that he was familiar and
12 aware of the information regarding the renewable builds
13 in this, in these two exhibits, he also referenced that
14 he thought people from his team probably provided a lot
15 of this information regarding what renewable builds had
16 been achieved under the IRP. I think this information is
17 relevant to this proceeding, it is certainly relevant to
18 testimony that's been put in this proceeding about the
19 amounts of renewables that DTE will hopefully be building
20 to serve these Data Centers, and goes directly towards
21 whether there are realistic plans for achieving RPS
22 compliance with the addition of large new loads. I
23 understand there's a renewable IRP and a renewable energy
24 docket coming down the pike, but one would certainly
25 assume and hope that planning would be occurring by the

1 utility before they signed on the large new customers
2 that they have to serve once they've signed them on. So
3 I think this all is relevant, directly relevant to the
4 testimony, and I think Mr. Bilyeu showed he was certainly
5 capable of testifying about the information regarding
6 renewables in these two reports, so I believe they should
7 come in.

8 JUDGE STALEY: I'm looking at these
9 documents again. So I agree with Mr. Janiszewski to the
10 extent that Mr. Bilyeu did testify he didn't prepare
11 these documents; he was familiar with them and he was
12 able to speak to a couple of elements of these documents,
13 but I don't know that that's to say that the entirety of
14 these documents are relevant to this case. I agree that,
15 with Mr. Janiszewski that Mr. Bilyeu has testified as to
16 components of this, and I think the nature of his
17 testimony, it supports what's in here, but only in part.
18 And so I don't think the entirety of these documents are
19 necessarily relevant to these proceedings, particularly
20 when these are for approval of the special contracts. I
21 think that his testimony to the extent of the, the
22 capacity that he discussed in the charts on both of them
23 are now part of the record, but I agree that the entirety
24 of these documents are not fully relevant to the issues
25 at hand. So I am going to deny the admission of these

1 documents, knowing that Mr. Bilyeu, his testimony
2 regarding the pieces for which he has information is of
3 record and that, to the extent it's relevant to this
4 case, can be used.

5 MR. FISK: O.K. Thank you, your Honor.
6 Appreciate it.

7 MR. JANISZEWSKI: Thank you, your Honor.

8 MR. FISK: If we could go off the record.

9 JUDGE STALEY: We're off the record.

10 (Recess from 3:21 p.m. until 3:41 p.m.)

11 JUDGE STALEY: We are back on the record
12 in Case No. U-22058, and I understand, Mr. Fisk, that
13 you've concluded your cross-examination?

14 MR. FISK: Yes. And we're going to move,
15 or I guess we're stipulating to the admission of MEC-26.

16 JUDGE STALEY: All right. Is that your
17 understanding, Mr. Janiszewski, that you agree to the
18 admission into evidence of Exhibit MEC-26?

19 MR. JANISZEWSKI: Yes, your Honor.

20 JUDGE STALEY: All right. Then Exhibit
21 MEC-26 is admitted into the record. Additionally, is
22 there any objection to the admission of Exhibit A-2?

23 Hearing none, Exhibit A-2 is admitted
24 into evidence.

25 All right. Mr. Janiszewski, any redirect
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1 for your clients?

2 MR. JANISZEWSKI: No, your Honor.

3 JUDGE STALEY: All right. Then I thank
4 you, Mr. Bilyeu, for your time today, and you're free to
5 go. And then I will have you, Mr. Janiszewski, complete
6 the bind in and admission of the remainder of your
7 witnesses and exhibits.

8 MR. JANISZEWSKI: Sounds good.

9 THE WITNESS: Thank you.

10 JUDGE STALEY: Thank you, Mr. Bilyeu.

11 THE WITNESS: Thank you.

12 (The witness was excused.)

13 - - -

14 MR. JANISZEWSKI: Would you like me to
15 proceed, your Honor?

16 JUDGE STALEY: One second. Go off the
17 record one second. Sorry.

18 (At 3:42 p.m., brief pause.)

19 JUDGE STALEY: All right. My apologies.
20 We're back on the record. Mr. Janiszewski, you can
21 proceed. How do you like to do it, do you want to go
22 through all of them at once, or would you like to take
23 each one at a time?

24 MR. JANISZEWSKI: Whatever your
25 preference is, your Honor.

1 JUDGE STALEY: Well, since we have quite
2 a few, why don't we do one at a time, one witness at a
3 time, we'll go from there.

4 MR. JANISZEWSKI: Sounds great. All
5 right. Thank you.

6 JUDGE STALEY: Starting with -- Go ahead.

7 MR. JANISZEWSKI: At this time, DTE
8 Electric moves to bind into the record the Qualifications
9 and Direct Testimony of Shawn D. Burgdorf consisting of a
10 cover sheet and 24 pages of questions and answers. The
11 Company also moves for the admission of the following ten
12 direct exhibits sponsored by Witness Burgdorf designated
13 as Confidential Exhibits A-5 and A-6, Exhibits A-7
14 through A-13, and Exhibit A-15, and there are no changes
15 to Witness Burgdorf's direct testimony or direct
16 exhibits. The Company also moves to bind into the record
17 the Rebuttal Testimony of Shawn D. Burgdorf consisting of
18 a cover sheet and 12 pages of questions and answers.
19 Witness Burgdorf did not sponsor any exhibits with his
20 rebuttal testimony, and there are no changes to Witness
21 Burgdorf's rebuttal.

22 JUDGE STALEY: All right. Are there any
23 objections to the binding in of the prefled Direct and
24 Rebuttal Testimony of Shawn D. Burgdorf, or the admission
25 of Exhibits Confidential A-5, Confidential A-6, Exhibit

1 A-7 through A-13, and Exhibit A-15?

2 Hearing none, the Direct and Rebuttal
3 Testimony of Shawn D. Burgdorf are bound into the record,
4 and Exhibits Confidential A-5 and Confidential A-6, as
5 well as Exhibits A-7 through A-13, and A-15, are admitted
6 into evidence.

7 (Direct Testimony and Rebuttal Testimony bound in.)

8 - - -

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of)
DTE ELECTRIC COMPANY)
for Approval of Special Contracts)
and for other relief)

Case No. U-22058

QUALIFICATIONS
AND
DIRECT TESTIMONY
OF
SHAWN D. BURGDORF

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

Line
No.

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

2 A1. My name is Shawn D. Burgdorf. My business address is 8001 Haggerty Road,
3 Suite 109, Belleville, Michigan 48111. I am employed by DTE Electric Company
4 (DTE Electric or Company).

5

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

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

8

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

10 A3. I received a Bachelor of Science Degree in Mechanical Engineering from
11 University of Michigan in 2005. I also received a Master of Business
12 Administration Degree from Eastern Michigan University in 2016.

13

14 **Q4. What is your work experience?**

15 A4. After receiving my Bachelor's degree from the University of Michigan in 2005, I
16 was employed by Consumers Energy Company (Consumers Energy). During my
17 initial employment at Consumers Energy, I worked in their production cost
18 modeling group where I supported the development of power supply forecasts using
19 the PROMOD® model. In 2009, I transferred positions to Transmission and
20 Regulatory Strategies where I was responsible for monitoring and analyzing filings
21 by the Midcontinent Independent System Operator ("MISO") at the Federal Energy
22 Regulatory Commission ("FERC"). I was also responsible for forecasting future
23 transmission and certain energy market-related costs in Power Supply Cost
24 Recovery ("PSCR") proceedings before the Michigan Public Service Commission
25 ("Commission" or "MPSC").

Line
No.

1 In 2012, I began my employment at DTE Electric within the Generation
2 Optimization Department. In 2015, I was promoted to a Supervisor position and
3 subsequently in October 2018, I was promoted to a Manager position within
4 Generation Optimization. In May 2025, I assumed responsibility as Manager over
5 the Market Strategy & Settlements team within Generation Optimization.

6

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

9 A5. Yes, I have attended Utility Rate School and the Advanced Regulatory Studies
10 Program, both hosted by the National Association of Regulatory Utility
11 Commissioners (“NARUC”) and The Institute of Public Utilities Michigan State
12 University. I also earned the certification of North American Electric Reliability
13 Corporation (“NERC”) Balancing and Interchange Operator.

14

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

16 A6. My current responsibilities include acquisition of wholesale electric power supply
17 to reliably and economically serve the energy requirements of the Company’s
18 customers including: negotiation and administration of contracts; settlement of
19 wholesale power market transactions; management of renewable energy credit
20 inventory; management of resource adequacy processes and review and advocacy
21 of Company recommendations regarding proposed MISO rules, regulations, and
22 business practices.

Line
No.

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

Line
No.

1	U-20836	DTE Electric's 2022 Main Rate Case
2	U-21193	DTE Electric's 2022 IRP
3	U-21297	DTE Electric's 2023 Main Rate Case
4	U-21534	DTE Electric's 2024 Main Rate Case
5	U-21860	DTE Electric's 2025 Main Rate Case

Line
No.

1 **Purpose of Testimony**

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

3 A8. The purpose of my testimony is to discuss the changes in capacity resource mix and
4 the Power Supply Cost impacts from the addition of Google LLC's (the Customer)
5 load. I will also discuss the major terms and conditions of the Company's Rider 12
6 ("R12") demand response contract with the Customer.

7
8 **Q9. How is your testimony organized?**

9 A9. My testimony consists of the following three sections:

10

11 **Section I:** Discussion of the "base case" capacity resource mix compared
12 to the capacity resource mix with the addition of the Customer's load in the
13 "Customer datacenter case".

14

15 **Section II:** Discussion of the Company's power supply costs projected from
16 2028 through 2047 with and without the Customer's load.

17

18 **Section III:** Discussion of the R12 demand response contract between the
19 Company and the Customer to support a portion of the capacity needs
20 associated with the Customer's load.

21

22 **Q10. Are you sponsoring any exhibits in this proceeding?**

23 A10. Yes, I am sponsoring the following exhibits:

24 Exhibit Description

25 A-5 Proxy Combined Cycle Gas Turbine ("CCGT") and Carbon Capture

Line
No.

1		and Sequestration (“CCS”) Capital and Fixed Costs - Confidential
2	A-6	Non-Fuel Variable Costs - Confidential
3	A-7	Projected Fuel, Purchases and Sales of Power, and PSCR Expense,
4		Years 2028-2047 Base Case
5	A-8	Projected Purchased Power, Sales, and Expense, Years 2028-2047
6		Base Case
7	A-9	Projected Fuel, Purchases and Sales of Power, and PSCR Expense,
8		Years 2028-2047 – Customer Datacenter Case
9	A-10	Projected Purchased Power, Sales, and Expense, Years 2028-2047
10		– Customer Datacenter Case
11	A-11	Power Supply Cost Recovery Rate – Base Case
12	A-12	Power Supply Cost Recovery Rate – Customer Datacenter Case
13	A-13	Power Supply Cost Recovery Rate – Delta (Customer Datacenter
14		Case minus Base Case)
15	A-15	Remaining Net Revenue Requirement – Proxy CCGT with CCS and
16		Solar

18 **Q11. Were these exhibits prepared by you or under your direction?**

19 A11. Yes, they were.

20

21 **Q12. Can you provide an overview of the Company’s approach to determining the**
 22 **impact of the Customer’s load on power supply costs?**

23 A12. Yes. The approach was to isolate the impact on power supply costs due to the
 24 addition of the Customer’s load. The Company first modeled¹ a “base case”

¹ Modeling was performed in EnCompass, a power planning software. DTE Electric uses EnCompass for capacity expansion and production cost modeling

Line
No.

1 resource plan based on currently known assumptions that resulted in a resource
2 adequate solution to efficiently serve existing customers.

3

4 The Company then added the Customer's load to the "base case" to determine if
5 incremental capacity resources are required to serve the Customer's load. The
6 second model, "Customer datacenter case", is inclusive of the Customer's load, the
7 additional resources from the Clean Capacity Accelerator Agreement ("CCAA") as
8 discussed by Witness Foley as well as other resources needed to comply with the
9 Midcontinent Independent System Operator ("MISO") requirements and ensure
10 resource adequacy. Witness Brooks defines resource adequacy, discusses the MISO
11 requirements, and modeled the resources of each case to demonstrate resource
12 adequacy, which he describes in his testimony.

13

14 After the resource additions were determined, as further discussed in Section I, the
15 Company assessed the power supply cost impacts between the two cases as
16 discussed in Section II.

17

18 **Q13. Are the modeling results intended to determine the future generation resource**
19 **mix or to identify a preliminary Integrated Resource Plan ("IRP") proposed**
20 **course of action ("PCA") to serve all customers?**

21 A13. No. The Company's future generation resources will be determined through the
22 Company's IRP that will be filed later this year. The modeling results were intended
23 to ensure resource adequacy needs were met with and without the Customer to
24 evaluate the impact on future costs.

Line
No.

Section I: Discussion of the “base case” capacity resource mix compared to the capacity resource mix with the addition of the Customer’s load in the “Customer datacenter case”.

Q14. How did the Company develop the “base case” resources for use in this filing?

A14. The Company’s current generation resources are assumed to continue operating through this study period, 2028 to 2047, with the exception of Monroe Units 3 and 4, which are expected to retire by the end of 2028, and Monroe Units 1 and 2, which are expected to retire by the end of 2032². The base renewable generation forecast is the Company’s latest Amended Renewable Energy Plan updated with the renewables associated with Oracle (see Witness Bilyeu for further discussion on renewable generation).

The “base case” also includes a total of approximately 4,800 MW of four-hour lithium-ion energy storage modeled to come online by 2036. The total energy storage resources are made up of (1) resources approved in the Company’s 2022 IRP, Case No. U-21193, (2) resources dedicated to the first data center customer (Case No. U-21190), and (3) economically optimized energy storage. These economic selections are driven by tax credits, favorable technology costs, high MISO Direct Loss of Load (“DLOL”)³ capacity accreditation and supporting planned increased levels of renewables. This modeling was performed solely to support the “Customer datacenter case” and is not intended to replace a comprehensive IRP. The 2026 IRP, planned to be filed later this year, will further refine the Company’s energy storage outlook and its role within the DTE Electric fleet.

² Assumption from the Company’s most recently approved IRP (Case No. U-21193).

³ [20241106 RASC Item 10 2024 RRA Update658159.pdf](#)

Line
No.

1 **Q15. Does the Company plan to delay the retirement of Monroe Power Plant to**
2 **serve the Customer?**

3 A15. No, the Company does not plan to delay the retirement of Monroe Power Plant to
4 serve the Customer. Per the 2022 IRP Settlement Agreement approved by the
5 Commission through its July 2023 Order in Case No. U-21193, the planned
6 retirement dates are 2028 for Units 3 and 4 and 2032 for Units 1 and 2. The
7 determination of future generation resources needed to replace Monroe Units 1 and
8 2 will occur in the Company's next IRP.

9
10 For the modeling in this filing, only the differences between the "base case" and
11 the "Customer datacenter case" are relevant for evaluating the cost impacts of
12 adding the Customer's load. The cost to replace Monroe Units 1 and 2 would be
13 identical in both cases. Therefore, in each case, the modeling assumes Monroe
14 Units 1 and 2 continue operating throughout the analysis period, serving as a
15 placeholder in each case for future replacement resources.

16
17 **Q16. How did the Company develop its "Customer datacenter case" resource plan?**

18 A16. The Company included the Customer's load and the resources from the CCAA as
19 described by Witness Foley which include the following:

- 20 • 450 MW⁴ of energy storage made up of:
 - 21 ○ 400 MW of 4-hour energy storage
 - 22 ○ 50 MW of 8-hour energy storage⁵
- 23 • 1,600 MW renewables⁶

⁴ CCAA specifies up to 480 MW

⁵ CCAA specifies approximately 50 MW of "long duration storage"

⁶ Refer to Witness Bilyeu's testimony for additional details

Line
No.

- 1 • 300 MW zonal resource credits (“ZRC”)

2 The Company also included approximately 250 MW of Customer demand
3 response. This is discussed in more detail in Section III of my testimony.

4

5 As Witness Brooks discusses in his testimony, the DTE Electric system is resource
6 adequate in 2029 with these resources. In 2033, however, additional “perfect
7 capacity⁷” is needed to ensure resource adequacy so a proxy generic combined
8 cycle gas turbine (“CCGT”) and carbon capture and sequestration (“CCS”) was
9 modeled to address this need. The Company’s upcoming IRP, to be filed later this
10 year, will ultimately determine the appropriate long-term resource and generation
11 mix. The CCGT and CCS added in this instant filing serves only as a proxy to
12 estimate the cost of an incremental resource in the customer benefit analysis
13 performed by Witness Willis.

14

15 **Q17. Why were the years 2029 and 2033 studied to determine resource adequacy?**

16 A17. Witness Brooks discusses why it is appropriate to analyze select years within a
17 long-term planning horizon. The year 2029 was selected because it is the first year
18 after the retirement of Monroe Units 3 and 4. The year 2033 was chosen due to the
19 expiration of both the 300 ZRCs under the CCAA and the approximately 250 MWs
20 of demand response in the Customer R12 contract on May 31, 2033. Given the loss
21 of these existing resources and the addition of new resources, it was reasonable to
22 evaluate both years to ensure the portfolio continues to meet the resource adequacy
23 standard.

⁷ Refer to Witness Brooks testimony for additional details on “perfect capacity”

Line
No.

1 **Q18. Can you describe the non-renewable resource changes from the “base case” to**
2 **the “Customer datacenter case”?**

3 A18. The primary resource changes between the “base case” and “Customer datacenter
4 case” are the acceleration of energy storage resources as well as the addition of a
5 “perfect capacity” resource described above (e.g. a proxy CCGT appropriately
6 sized in the “Customer datacenter case”) and defined by Witness Brooks in his
7 testimony. In the “Customer datacenter case,” 500 MW of energy storage capacity
8 is accelerated compared to the “base case” where these resources were projected to
9 come online in later years. As previously discussed in the CCAA, an additional 50
10 MW of 8-hour energy storage, fully funded by the Customer, is shown in 2029. As
11 Witness Foley notes, this can be any long-duration storage technology; for the
12 purposes of this modeling, a 50 MW 8-hour storage asset is assumed to replace 100
13 MWs of 4-hour storage in 2036 from the base case. Additionally, once the ZRC
14 contract and the contracted demand response end on May 31, 2033, a proxy
15 dispatchable resource is modeled to support resource adequacy.

16

17 **Q19. Can you summarize the resource changes occurring between the “base case”**
18 **and “Customer datacenter case”?**

19 A19. Yes. See Table 1 below that shows the change in resources from the “base case” to
20 the “Customer datacenter case.” The addition of 450 MW of storage earlier in the
21 build plan for the “Customer datacenter case” results in a reallocation of 100 MW
22 of lithium-ion four-hour storage reconfigured as 50 MW of 8-hour storage when
23 comparing cases. In addition, including 1,600 MW of customer owned renewables
24 reduces the overall renewable build by 200 MW in 2033 and 50 MW in 2034 in the

Line
No.

1 “Customer datacenter case”. No changes in resources we made after 2036 that differ
2 between the cases.

3

4 **Table 1: “Customer Datacenter Case” resource changes from “Base Case”**
5 **(nameplate (MW))**

	2028	2029	2030	2031	2032	2033	2034	2035	2036
Demand Response	250					(250)			
Renewable Energy ⁸			500	700	400	(200)	(50)		
4-Hour Energy Storage	200	200						(200)	(300)
8-Hour Energy Storage		50							
ZRC Contract	300					(300)			
Proxy CCGT w/CCS						727		(81)	

6 Black = additions, red = subtractions

7

8 **Q20. What price assumptions were used in the modeling of the proxy CCGT with**
9 **CCS in the “Customer datacenter case”?**

10 A20. The Company utilized a third-party forecast, Wood Mackenzie, for plant capital
11 cost, CCS capital cost, and non-fuel operating and maintenance (O&M)
12 assumptions for a new 727 MW CCGT with CCS. These projected cost inputs from
13 Wood Mackenzie were applied directly into the model and the model calculated the
14 annual revenue requirement for the proxy CCGT with CCS. The annual revenue
15 requirement for the proxy CCGT with CCS was an output of the model which
16 incorporated various components such as depreciation expense, non-fuel O&M,
17 property tax, allowed return, and federal production tax credits associated with the
18 CCS system. The associated revenue requirements are shown in Confidential

⁸ Refer to Witness Bilyeu’s testimony for additional detail

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1 Exhibits A-5 and A-6 and were provided to Witness Willis to use in the overall
2 customer benefit analysis. The fuel expense, energy revenues, and capacity
3 revenues associated with the proxy CCGT with CCS resource are also included in
4 the PSCR expense forecast for the “Customer datacenter case.”

5

6 **Q21. What price assumptions were used in the modeling of the energy storage in the**
7 **“Customer datacenter case”?**

8 A21. The Company developed energy storage price assumptions using information from
9 two sources. Capital cost assumptions were based on up-to-date market-based cost
10 information obtained through the Company’s 2025 energy storage Request For
11 Proposal (“RFP”). For fixed operating cost assumptions, the Company relied on
12 data from the National Renewable Energy Laboratory’s (“NREL”) 2024 Annual
13 Technology Baseline (“ATB”). These projected cost inputs were applied directly
14 into the model similar to the proxy CCGT with CCS mentioned above. The
15 associated revenue requirements are shown in Confidential Exhibit A-5 and were
16 provided to Witness Willis to use in the overall customer benefit analysis. The
17 energy and capacity revenues associated with the energy storage resources are also
18 included in the PSCR expense forecast for the “Customer datacenter case.”

19

20 **Q22. Does the proxy CCGT with CCS resource provide value to other customers**
21 **following the conclusion of the Customer contract in 2047?**

22 A22. As described earlier in my testimony, this is a proxy asset used for modeling
23 purposes; the 2026 IRP will determine the appropriate resources needed to serve
24 DTE Electric customers, as well as assumptions on the revenue requirement of the
25 asset(s) over their depreciable lives. In the context of this proxy asset modeled in

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1 this case, should the Customer choose to not extend its contract beyond 2047, this
2 asset would provide market value for customers, and may offset potential future
3 resource development costs (e.g., offsetting incremental capacity and energy to
4 replace potential retiring resources in this timeframe).

5

6 **Q23. What is the approximate remaining revenue requirement of a proxy CCGT**
7 **with CCS after 2047?**

8 A23. Wood Mackenzie forecasts a 35-year lifespan of a CCGT with CCS which was
9 used in this analysis. Based on the 35-year lifespan schedule, the remaining revenue
10 requirement after 2047 is forecasted to be approximately \$1.0 billion on a net
11 present value (“NPV”) basis (Exhibit A-15, line 21, column (b)). At the conclusion
12 of the contract with the Customer, 74% of the cost of this asset has been paid off
13 based on a NPV basis.

14

15 **Q24. Are there market revenues that offset the remaining revenue requirement of**
16 **the proxy CCGT with CCS?**

17 A24. Yes. The modeled value of the proxy CCGT with CCS for both energy and capacity
18 is approximately \$142 million annually in 2038. Assuming the proxy CCGT with
19 CCS continued to receive similar market value inflated over 2048 – 2067
20 timeframe, that would equate to approximately \$647 million on an NPV basis
21 (Exhibit A-15, line 22, column (b)).

22

23 **Q25. Can you provide an example of how the proxy CCGT with CCS may displace**
24 **the potential need for another resource in 2048 (e.g., offsetting incremental**
25 **capacity and energy to replace potential retiring resources)?**

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1 A25. Yes. In this timeframe, there may be resources within DTE Electric's existing
2 generation fleet that are nearing retirement. Should one of those resources be
3 scheduled for retirement in this timeframe, this resource could displace the need for
4 new replacement resources. For example, based on the current economic outlook,
5 storage is one of the most economic capacity resources that may be selected as a
6 new resource in 2048 to fill the need created from potential existing asset
7 retirements. A 4-hour lithium-ion storage resource of approximately 576 MW
8 nameplate capacity would receive similar projected MISO capacity accreditation
9 as a proxy CCGT with CCS with a nameplate capacity of 646 MW in the Summer
10 Season. The 576 MW storage resource net revenue requirement over 2048 – 2067
11 on a NPV basis would be approximately \$212 million (Exhibit A-15, line 23,
12 column (c)). Thus, to replace other potentially retiring DTE Electric resources, the
13 proxy CCGT with CCS (Exhibit A-15, line 24, column (b)) avoids the \$212 million
14 net revenue requirement of a 576 MW storage resource.

15

16 **Q26. Is there value in the “Customer Datacenter case” resources (specifically the**
17 **proxy CCGT with CCS and remaining life of solar resources) to recover the**
18 **remaining costs after the contract with the Customer ends in 2047?**

19 A26. Yes. The remaining net revenue requirement, after including the avoided \$212
20 million storage resource as described above, results in approximately \$151 million
21 for the proxy CCGT with CCS (Exhibit A-15, line 24, column (b)). This is offset
22 by the remaining market value of \$226 million from the solar resources resulting in
23 a net benefit of approximately \$75 million (Exhibit A-15, line 26, column (b)) on a
24 NPV basis. This projection after the Customer contract ends in 2047 shows that

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1 generation resources will continue to provide customer value beyond the analysis
2 performed by Witness Willis.

3

4 **Section II: Discussion of the Company's power supply costs projected from 2028**
5 **through 2047 with and without the Customer's load.**

6 **Q27. After identifying the resource mix for each case, how did the Company**
7 **determine the impact on the Company's power supply costs?**

8 A27. The Company projected power supply costs for both the "base case" and the
9 "Customer datacenter case" using the modeling results. The Company then
10 calculated and compared the resulting rates to quantify the difference in power
11 supply cost rates between the two cases. This approach was used to isolate the
12 impact of the Customer's load and associated resources on power supply costs.

13

14 **Q28. What are the major assumptions in your "base case"?**

15 A28. Table 2 below shows the major assumptions and the source.

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1

Table 2: “Base Case” major assumptions

Topic	Assumption	Source
Timeframe	2028 – 2038 – modeled in Encompass 2039 – 2047 – held 2038 values flat for model assumptions	Primary Supply Agreement (PSA), 2039 – 2047: Customer load at full load, no further associated resource changes; modeling is focused on the changes between the two cases
Load Forecast	PSCR Forecast + Oracle Load	PSCR Plan (U-21875) + Oracle Filing (U-21990)
Market Price Forecast (energy and capacity)	PSCR Forecast MI Hub basis - energy	PSCR Plan (U-21875) Third-party Siemens forecast
Renewables	Amended REP through 2036 plus incremental Oracle renewables	Amended REP (U-21662) + Oracle Filing (U-21990)
Monroe Units 3 & 4	Retired in 2028	2022 IRP Settlement (U-21193)
Monroe Units 1 & 2	Operates through 2032 then proxy resource called “TBD Resource(s)” incorporated	2022 IRP Settlement (U-21193). Units 1&2 will retire in 2032; replacement resources will be determined in next IRP as addressed in Section I
Transmission	PSCR Forecast + Oracle Load	PSCR Plan (U-21875) + Oracle Filing (U-21990)
Non-PSCR Sales	PSCR Forecast + Oracle Load	PSCR Plan (U-21875) + Oracle Filing (U-21990)
Fuel & Chemical Prices	PSCR Forecast	- Coal - Market Forwards escalated by Consumers Price Index - Natural Gas – Third-party Siemens forecast - Chemicals – PSCR Plan (U-21875)
Other Existing Generation	Continue to operate	PSCR Plan (U-21875) + Oracle Filing (U-21990)
Energy Storage	PSCR Forecast + Oracle energy storage	(U-21193) (U-21990) - Economically optimized

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1 **Q29. What information does Exhibit A-7 and Exhibit A-8 show?**

2 A29. Exhibit A-7 and Exhibit A-8 show a summary by year of the various power supply
3 cost categories for the “base case”.

4

5 **Q30. What were the assumed transmission costs for the base case?**

6 A30. The transmission costs for the “base case” are shown on Exhibit A-7, line 30. These
7 costs are projected based on a forecast of MISO charge types associated with
8 transmission for the International Transmission Company (ITC) pricing zone.
9 These transmission costs are consistent with the costs forecasted in the 2026 PSCR
10 Plan plus estimated costs associated with the first data center customer.

11

12 **Q31. How did the Company forecast fuel prices?**

13 A31. The coal price forecast was based on pricing forwards through 2030 and then
14 escalated by the consumer price index (“CPI”). The natural gas price assumptions
15 utilized the third-party Siemens projections that were used in the PSCR Plan.

16

17 **Q32. What are the Non-PSCR Customer Sales and Transmission Adjustments?**

18 A32. The Non-PSCR Customer Sales and Transmission Adjustments relate to the sales
19 made to R-10 interruptible customers, R-3 Standby and Supplemental Service
20 customers. These sales are not PSCR sales and are not included in determining
21 recoverable PSCR expense. The Non-PSCR Customer Sales and Transmission
22 Adjustments credit PSCR customers incremental expense to serve these sales.

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1 **Q33. What information does Exhibit A-9 and Exhibit A-10 show?**

2 A33. Exhibit A-9 and Exhibit A-10 show a summary by year of the various power supply
3 cost components for the “Customer datacenter case”.

4
5 **Q34. What changes were made in the “Customer datacenter case” from the “base
6 case” that impact the power supply costs?**

7 A34. The resource mix changes discussed in Section I of my testimony impact the
8 purchases and sales, capacity and fuel and chemical costs. Other changes made to
9 the “base case” assumptions listed in Table 2 include: the addition of the
10 Customer’s load in the load forecast and the transmission cost assumptions
11 associated with the Customer’s load. Refer to Witness Benyard for additional
12 details on transmission costs.

13
14 **Q35. What are the assumed transmission costs for the “Customer datacenter case”?**

15 A35. The transmission costs for the “Customer datacenter case” are shown on Exhibit A-
16 9, line 30. There are two impacts to transmission expense for the “Customer
17 datacenter case” – the impact from the transmission investments necessary to serve
18 the Customer and the impact from the inclusion of the Customer’s load in the
19 Company’s transmission expense allocation.

20

21 First, transmission expense is impacted by the transmission investments necessary
22 to serve the Customer. Based on initial estimates provided by the Company’s
23 transmission provider and as discussed by Witness Benyard, the Company expects
24 that approximately \$308 million of capital investment by ITC will be needed to
25 upgrade the transmission system to connect the Customer to the electric grid. The

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1 transmission provider's investment is recovered from the Company (and others) via
2 MISO Schedule 9, which is a component of the Company's transmission expense.

3
4 Second, transmission expense is impacted by the inclusion of the Customer's load
5 in the Company's transmission expense allocation. The MISO Schedules that
6 comprise the Company's transmission expense, including Schedules 1, 9, 10, 10-
7 FERC, 26, 26-A, and 26-C, are allocated based on the Company's peak demand
8 and energy usage. Since the Customer's load increases both the Company's peak
9 demand and energy use, the Customer's load impacts transmission expense.

10

11 **Q36. Can you explain the impact to transmission expense when comparing the**
12 **"Customer datacenter case" to the "base case"?**

13 A36. Yes. The transmission expense for the "base case" is shown on Exhibit A-7, line
14 30. For 2029, the "base case" transmission expense is \$798 million. The
15 transmission expense for the "Customer datacenter case" is shown on Exhibit A-9,
16 line 30. For 2029, the "Customer datacenter case" transmission expense is \$889
17 million. When comparing the cases, the impact on the 2029 transmission expense
18 is \$91 million.

19

20 **Q37. Are the Company's other customers adversely impacted by the increased**
21 **transmission expense?**

22 A37. No, the Company's existing customers will not be adversely impacted by the
23 increased transmission expense. Even though the overall transmission expense is
24 increasing, the effective transmission rate for all customers decreases due to the
25 large increase in load from the Customer, who also pays a portion of the Company's

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1 transmission expense through PSCR allocations. For example, the “base case”
2 transmission expense in 2029 is \$798 million and the load forecast is 53,812 GWh,
3 producing a transmission unit cost of \$0.0148/kWh. Whereas in the “Customer
4 datacenter case”, transmission expense increases to \$889 million in 2029 while the
5 associated load increases to 61,819 GWh, resulting in a lower transmission unit
6 cost of \$0.0144/kWh. The Company’s other customers receive the benefit of the
7 lower transmission unit cost which is included in the PSCR benefit for other
8 customers described below and utilized in Witness Willis’ Exhibit A-19.

9

10 **Q38. What is the impact of the additional Customer load on existing PSCR rates?**

11 A38. The addition of the Customer’s load and resources paid for by the Customer results
12 in a net PSCR benefit to the Company’s other customers. Other customers benefit
13 from the resources paid for by the Customer with total wholesale revenues shown
14 in Exhibit A-10, line 78, being greater than the credits provided to the Customer
15 shown on line 79. Additionally, the Customer’s load is paying for various power
16 supply costs that result in lower rates (e.g. transmission costs as discussed above
17 and renewable compliance build). The PSCR rates are shown for the “base case”
18 in Exhibit A-11 and the “Customer datacenter case” in Exhibit A-12. The
19 differences in the PSCR rates are shown in Exhibit A-13. As described, there is a
20 net benefit over the 20 years to existing PSCR customers and the increased load
21 from the Customer resulting in lower rates. The total power supply cost change for
22 existing customers due to the Customer’s load is shown in Exhibit 13, line 9 and
23 was provided to Witness Willis for use in his customer benefit analysis.

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Section III: Discussion of the R12 demand response contract between the Company and Customer to support a portion of the capacity needs associated with the Customer's load

Q39. What is the R12 demand response contract that the Company has executed with the Customer?

A39. The Company's Rider 12 allows for flexible demand response arrangements with its customers. The Customer's R12 contract accounts for the risks of the large load addition, ensures other customers remain financially unharmed, and accounts for current MISO Rules and future reforms as they relate to Load Modifying Resources ("LMR"). The contract is for a reduction in load to a Firm Service Level ("FSL") of 65% of the customer committed capacity ramp during the load ramp period as well as when the Customer is at full load (65% of the full 1000 MW). The contract is one of the additional resources needed to meet the MISO resource adequacy requirements for the increase in load from the Customer as further discussed above and by Witness Brooks.

Q40. What are the major terms and conditions for the R12 demand response contract with the Customer?

A40. The contract is for an amount of approximately 250 MWs of demand response with the corresponding accredited ZRCs for MISO's resource adequacy construct. The contract term begins 6/1/2027 and ends 5/31/2033 and requires a firm service level of 650 MW

Q41. Does the contract meet the current MISO requirements and those expected to be in place beginning in 2028 to receive the full accreditation value?

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1 A41. Yes, the contract meets the current MISO requirements and those expected to be in
2 place beginning in 2028.

3

4 **Q42. How does the Firm Service Level of 650 MW equate to approximately 250 MW**
5 **of load reduction?**

6 A42. The Company modeled the Customer's expected load based on the Customer's
7 input of approximately a 90% load factor for a 1,000 MW load (equates to 900
8 MW). A FSL of 650 MW means that the Customer must reduce their actual load
9 to below 650 MW if called upon by MISO during an emergency. The reduction to
10 650 MW must occur even if the Customer is using 1,000 MW at the time the
11 reduction is called upon. Thus, the amount of actual load reduction can vary, but
12 must reach the 650 MW FSL. The approximate average Customer load of 900 MW
13 minus the 650 MW FSL equates to approximately 250 MW of demand response.

14

15 **Q43. Do the contract damages for non-performance adequately cover any financial**
16 **costs to the Company?**

17 A43. Yes. The damages are structured in a way to ensure that all potential MISO
18 penalties are assessed to the Customer. First, the damages imposed by MISO
19 during the current MISO Planning Year (PY) for any non-performance will be
20 directly assessed, including any accredited ZRCs that are disqualified. The
21 Company also assesses additional damages at two times the contract price for the
22 non-performance amount. Second, any future MISO PY lost accreditation for non-
23 performance will be assessed damages for the lost ACP revenues plus at least the
24 CONE. This ensures full recovery of any lost revenues from the Planning Resource

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1 Auction. The addition of CONE is reasonable to incentivize the demand response
2 performance to help ensure reliability.

3

4 **Q44. Does this complete your direct testimony?**

5 A44. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of)
DTE ELECTRIC COMPANY)
for Approval of Special Contracts)
and for other relief)

Case No. U-22058

REBUTTAL TESTIMONY

OF

SHAWN D. BURGDORF

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF SHAWN D. BURGDORF

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

3 A1. My name is Shawn D. Burgdorf. My business address is 8001 Haggerty Road,
 4 Suite 109, Belleville, Michigan 48111. I am employed by DTE Electric Company
 5 (DTE Electric or Company).

6

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

9 A2. Yes.

10

11 **Purpose of Testimony**

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

13 A3. The purpose of my rebuttal testimony is to respond to several intervenors and
 14 positions, including those of Association of Businesses Advocating for Tariff
 15 Equity (ABATE), the Michigan Energy Innovation Business Council / Institute for
 16 Energy Innovation/Ecology Center/Environmental Law and Policy Center/Union
 17 of Concerned Scientists / Vote Solar (MEICEO), Michigan Environmental Council
 18 / Natural Resources Defense Council / Sierra Club (MNS), the Attorney General
 19 (AG), and the Great Lakes Renewable Energy Association (GLREA). These
 20 include:

21 1.) Resource Planning

- 22 • MNS Witness Woods's recommendation that "The Commission
- 23 should disregard all information DTE has provided regarding the
- 24 various benefits of the CCGT [combined cycle gas turbine] plus
- 25 CCS [carbon capture and sequestration] proxy that was

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- 1 developed for the singular purpose of performing the
- 2 Company's customer benefit analysis..." (page 19, lines 6-13)
- 3 • ABATE Witness Dauphinais's discussion on the Company's
- 4 analysis of remaining net book value of the proxy CCGT with
- 5 CCS (page 19, lines 8-24 and page 20, lines 1-13)
- 6 • MEICEO Witness Kenworthy's claim that DTE Electric's
- 7 estimated \$1.7 billion customer benefit calculation does not
- 8 demonstrate that the Company's proposals are cost effective
- 9 (page 31, lines 9-23 and page 32, lines 1-11)

10 2.) Transmission Costs

- 11 • MEICEO Witness Kenworthy states that "Specifically, the
- 12 record does not demonstrate how much of the \$91 million
- 13 increase in 2029 transmission expense reflects the International
- 14 Transmission Company (ITC) capital recovery through
- 15 Schedule 9 versus the increase in other Midcontinent
- 16 Independent System Operator (MISO) schedule charges driven
- 17 by the Customer's coincident peak contribution, which MISO
- 18 itself allocates based on peak demand, not energy volume" (page
- 19 27, lines 6-10) and that "Burgdorf does not describe the specific
- 20 methodology or inputs used to derive that allocation change"
- 21 (page 28, lines 7-8)

22 3.) Demand Response (DR) Provisions

- 23 • AG Witness Coppola's recommendation "that any penalties
- 24 assessed to Google for non-performance under the DR program
- 25 should be accounted for separately, disclosed in DR proceedings

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1 and general rate cases, and credited to other customers' rates."

2 (page 9, lines 3-6)

3 4.) Resource Adequacy in 2033

4 • MEICEO Witness Hotaling's confusion on DTE Electric's
5 responses in discovery compared to testimony from the
6 statement "DTE's responses to discovery questions on the
7 perfect capacity resource do not appear to be aligned with what
8 was said in testimony." (page 13, lines 1-2)

9 5.) Scarcity Cost Fees

10 • GLREA Witness Richter's recommendation that "the
11 Commission should be open to imposing temporary "scarcity
12 cost" fees on service to data center customers, until the scarcity
13 of supplies is resolved by market adjustments" (page 49, lines
14 19-21)

15

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

17 A4. No.

18

19 **Resource Planning**

20 **Q5. Do you agree with MNS Witness Woods's recommendation that "The**
21 **Commission should disregard all information DTE has provided regarding the**
22 **various benefits of the CCGT plus CCS proxy that was developed for the**
23 **singular purpose of performing the Company's customer benefit analysis..."**
24 **(page 19, lines 6-13)?**

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1 A5. No. The Company's upcoming integrated resource plan (IRP) will determine the
2 optimal resource mix to address reliability needs on a system-wide basis. The proxy
3 CCGT with CCS used in this proceeding is a reasonable assumption for purposes
4 of quantifying the net customer benefit, which stands on its own merits in this case
5 independent of future IRP outcomes.

6

7 **Q6. Do you agree with ABATE Witness Dauphinais's discussion on the Company's**
8 **analysis of remaining net book value of the proxy CCGT with CCS (page 19,**
9 **lines 8-24 and page 20, lines 1-13)?**

10 A6. No. Witness Dauphinais discusses the analysis DTE Electric performed and
11 presented in Exhibit A-15, which shows the costs offset by potential benefits of the
12 remaining life of the proxy CCGT with CCS. Witness Dauphinais performs a
13 single sensitivity assuming 0% growth in energy and capacity prices throughout the
14 entire 2048-2067 period to arrive at a net cost of the remaining assets of \$129.55
15 million on a net present value (NPV) basis. This assumption is neither reasonable
16 nor consistent with inflationary price impacts that consistently rise over time.
17 Moreover, even under Witness Dauphinais' sensitivity, there is no material change
18 to the Company's expectation of customer benefits.

19

20 **Q7. ABATE Witness Dauphinais points out that "DTE conducted no sensitivity**
21 **analysis" (page 20, line 4). Why did the Company not perform a sensitivity**
22 **analysis?**

23 A7. The Company's presentation of potential benefits during the post-contract years
24 from 2048–2067 was developed using a representative capacity resource (i.e.
25 storage) displaced by the proxy CCGT with CCS. The representative resource type

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1 was chosen based on being the economic resource selection in the base case
2 modeling results. The Company believes this is a conservative approach as the net
3 customer benefits would likely be greater than those shown in Exhibit A-15 under
4 other scenarios where other types of resources are displaced. In addition,
5 performing resource-type sensitivities over that horizon (two to four decades into
6 the future) would require speculative assumptions about resource availability,
7 technology costs, and market structures that cannot be reliably forecasted today.
8 Thus, the Company did not perform a sensitivity analysis for that period.

9

10 **Q8. MEICEO Witness Kenworthy claims that DTE Electric's estimated \$1.7**
11 **billion benefit calculation does not demonstrate its proposals are cost effective**
12 **(page 31, lines 9-23 and page 32, lines 1-11). Was it the intention of the**
13 **Company to provide a full resource planning evaluation in this proceeding?**

14 A8. No. To clarify, Witness Kenworthy does not argue that the Company's
15 affordability benefit analysis is incorrect or overstated. Rather, his position is that
16 the analysis does not reflect the potential effect of alternative resource procurement
17 approaches — including third-party-funded resources, customer-side flexibility,
18 and Virtual Power Plants — that MEICEO Witness Sherman identifies in her direct
19 testimony. Witness Kenworthy argues that the Commission's evaluation of the
20 reasonableness of the contracts should include whether the proposed contracts
21 represent the most cost-effective approach to serving the Customer's (Google LLC)
22 load.

23

24 That argument does not undermine the Company's showing in this proceeding. The
25 Company's customer benefit analysis evaluates the contracts and resource

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1 assumptions presented for approval in this case, including the Customer's load,
2 revenues and obligations under the PSA and CCAA, the demand response contract,
3 and the proxy CCGT with CCS. The analysis demonstrates an estimated \$1.7
4 billion benefit to other customers. The purpose of this proceeding is not to conduct
5 a full resource-planning optimization or to select the Company's future resource
6 portfolio. That evaluation will occur in the Company's upcoming IRP, which is the
7 appropriate forum for determining the optimal resource mix on a system-wide
8 basis. The IRP — not a special contract approval proceeding — is the appropriate
9 forum for optimizing resource procurement.

10

11 **Transmission Costs**

12 **Q9. MEICEO Witness Kenworthy states that “Specifically, the record does not**
13 **demonstrate how much of the \$91 million increase in 2029 transmission**
14 **expense reflects the ITC capital recovery through Schedule 9 versus the**
15 **increase in other MISO schedule charges driven by the Customer's coincident**
16 **peak contribution, which MISO itself allocates based on peak demand, not**
17 **energy volume” (page 27, lines 6-10) and that “Burgdorf does not describe the**
18 **specific methodology or inputs used to derive that allocation change” (page 28,**
19 **lines 7-8). How much of the \$91 million increase in 2029 transmission expense**
20 **is due to the ITC capital recovery vs. increases driven by the Customer's load?**

21 **A9.** The \$91 million difference in 2029 transmission expense between the “base case”
22 and the “Customer datacenter case” is attributable to two factors: (1) \$49.2 million
23 in estimated ITC network upgrade costs charged through Schedule 9; and (2) \$41.8
24 million in estimated load-driven increases across all transmission schedules. The
25 detailed breakdown by schedule is shown in Table 1 below.

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1

Table 1 2029 Transmission Expense Comparison

Transmission Schedule	Base Case (\$000s)	Customer DC Case (\$000s)	Difference (\$000s)
Schedule 1	4,422	4,929	507
Schedule 9 Total	513,792	567,202	53,410
<i>Customer Load</i>	<i>513,792</i>	<i>517,965</i>	<i>4,173</i>
<i>Network Upgrades</i>	<i>0</i>	<i>49,237</i>	<i>49,237</i>
Schedule 10	19,932	22,529	2,597
Schedule 10 – FERC Transmission	6,442	7,179	737
Schedule 26	27,315	27,536	222
Schedule 26-A	225,938	259,554	33,617
Schedule 26-C	71	71	-
TOTAL	797,911	889,001	91,090

2

3 **Q10. What are the components of the transmission expense forecasts that supported**
4 **the “base case” and the “Customer datacenter case” and how were they**
5 **allocated?**

6 A10. The total transmission expense forecasts are shown in Exhibit A-7 and Exhibit A-
7 9. The components of the transmission expense forecasts for the “base case” and
8 the “Customer datacenter case” include Schedules 1, 9, 10, 10-FERC, 26, 26-A and
9 26-C (shown in Table 1 as supported by previously provided workpapers to discovery
10 requests), which are transmission service schedules under the MISO Tariff. Each
11 transmission schedule is derived by multiplying a forecasted rate by either the peak
12 demand (i.e., in MW) or the total system usage (i.e., in MWh) depending on the
13 schedule.

14

15 **Q11. Is the entire Schedule 9 difference due to the estimated ITC network upgrade**
16 **costs related to the customer?**

17 A11. No. Schedule 9 is charged based on peak load, and as a result, the Customer’s load
18 also impacts the Schedule 9 expense. If the \$308 million ITC network upgrade costs

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1 are removed from the analysis, the forecasted 2029 Schedule 9 expense is \$518.0
2 million. Therefore, approximately \$4.2 million of the Schedule 9 difference is
3 associated with the Customer's load and approximately \$49.2 million is associated
4 with the ITC network upgrade costs.

5

6 In summary, of the \$91 million increase in 2029 transmission expense,
7 approximately \$49.2 million is associated with estimated ITC network upgrade
8 costs. The remaining estimated \$41.8 million is associated with the Customer's
9 load impacting the Company's total load.

10

11 **Demand Response Provisions**

12 **Q12. Do you agree with AG Witness Coppola's recommendation "that any penalties**
13 **assessed to Google for non-performance under the DR program should be**
14 **accounted for separately" (page 9, lines 3-5)?**

15 A12. Yes. The Company will assess any non-performance penalties associated with the
16 Rider 12 contract directly to the Customer as discussed in my direct testimony Q43.
17 Thus, these penalties will be tracked separately.

18

19 **Q13. Do you agree with AG Witness Coppola's suggestion that the non-**
20 **performance penalties be "disclosed in DR proceedings and general rate cases,**
21 **and credited to other customers' rates." (page 9, lines 5-6)?**

22 A13. No. The Company intends to track any such non-performance penalties through
23 Power Supply Cost Recovery (PSCR) Reconciliation proceedings; this is the forum
24 in which demand response revenues and performance are currently addressed and
25 is the appropriate mechanism for tracking any such penalties. Any penalties

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1 directly assessed by MISO will be a reduction in power supply costs booked to all
2 other customers. Penalties assessed by the Company for future lost accreditation
3 will also be shown as a reduction in power supply costs. The Company agrees with
4 Witness Coppola that the penalties should be credited to other customers, however,
5 the proper proceeding should be the PSCR Reconciliation that reflects the year in
6 which any penalties occur.

7

8 **Resource Adequacy in 2033**

9 **Q14. Do you believe the Company's responses to discovery do not align with**
10 **testimony as stated by MEICEO Witness Hotaling "DTE's responses to**
11 **discovery questions on the perfect capacity resource do not appear to be**
12 **aligned with what was said in testimony." (page 13, lines 1- 2)?**

13 A14. No. My direct testimony (as referenced by Witness Hotaling on page 13, lines 3-
14 4) stated "Additionally once the ZRC contract and the contracted demand response
15 end on May 31, 2033, a proxy dispatchable resource is modeled to support resource
16 adequacy." This distinctly states that the proxy dispatchable resource is modeled to
17 support resource adequacy when the ZRC contract and demand response contract
18 end as performed in the modeling by Witness Brooks for 2033. The Company's
19 discovery response to CEOMEIBCIEIDE-1.20b, labeled as Exhibit MEICEO-13,
20 states that "The proxy CCGT with CCS was added to meet the total system
21 reliability requirement needs in 2033..." which is a true statement based on the
22 reliability need identified by Witness Brooks. The same discovery response in
23 Exhibit MEICEO-13 affirmed the statement in my direct testimony about the ZRC
24 and demand response contracts expiring in 2033 with the following sentence
25 "While the expiration of the ZRC contract and demand response are factored into

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1 the 2033 analysis, they do not define the 2033 system reliability requirements.” To
2 be clear, the 2033 system reliability requirements are set by the combination of all
3 load and resource changes on the system.
4

5 **Q15. Can you address Witness Hotaling’s request that “the Company should**
6 **provide clarity on rebuttal as to whether the Customer’s load and removal of**
7 **the ZRCs and demand response in 2033 is driving the resource adequacy need**
8 **and the proxy CCGT with CCS included in the Company’s modeling results.”**
9 **(page 13, lines 25-28)?**

10 A15. As discussed in the previous question, the ZRC and demand response resources are
11 not included in the modeling, after their scheduled expiration dates, performed in
12 2033 for resource adequacy. The Company has not attempted to isolate the precise
13 contribution of each individual assumption to the 2033 reliability need because that
14 would require a separate counterfactual reliability analysis. Multiple factors can
15 affect the 2033 reliability need, including native load growth, supply-side resource
16 changes, and the availability of non-firm energy from MISO. The Company’s
17 upcoming IRP will holistically evaluate resource adequacy and identify the least-
18 cost, reliable means of serving customers on a system-wide basis.
19

20 **Scarcity Cost Fees**

21 **Q16. GLREA Witness Richter suggests that “the Commission should be open to**
22 **imposing temporary ‘scarcity cost’ fees on service to data center customers”**
23 **(page 49, lines 19-21) because data centers are driving up the prices of power**
24 **equipment and MISO energy and capacity. Should the Commission consider**
25 **imposing these fees?**

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1 A16. No, the Commission should not consider imposing “scarcity cost” fees to the
2 Customer in this case or to any other data center customer. Witness Richter’s own
3 testimony undermines the premise of his proposal, as he acknowledges that the
4 Customer has demonstrated “a very concerted effort to prevent this data center from
5 impacting other DTE Electric customers, at considerable cost to themselves” (page
6 22, lines 3-4). Despite having acknowledged the adequacy of provisions set forth
7 in the PSA and CCAA (pages 22-24), Witness Richter offers no explanation for
8 why an additional “scarcity cost” fee is warranted notwithstanding the very
9 protections he commends.

10

11 Witness Richter concedes that any potential price increases due to data centers as a
12 group are “*indirect* costs” (page 49, line 17) that are not caused by the Company’s
13 agreements with the Customer. Indeed, Witness Richter himself acknowledges the
14 distinction, testifying that “[t]he cost impact of data centers as a group is different
15 than the cost impact of any particular data center” (page 48, lines 14-15), that
16 “[d]emand across the country, and the world, has caused these price increases”
17 (page 48, lines 13-14), and that the alleged risk his scarcity cost fees proposal
18 addresses is “not particular to *this* data center, but apply to all hyperscale data
19 centers” (page 28, line 20 through page 29, line 8). By confirming the costs as
20 indirect, Witness Richter has made no attempt to identify the requisite causal
21 relationship between the Customer and the alleged indirect costs. Nor has Witness
22 Richter provided any evidence that the Company’s agreements with the Customer
23 have or will increase prices of power equipment or MISO energy and capacity.

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1 Further, Witness Richter has made no actual proposal for the Commission to
2 evaluate and offered only general commentary which is neither specific to the
3 Company nor the issues before the Commission in this proceeding. As such, there
4 is nothing substantive for the Commission to evaluate, and the Commission should
5 reject Witness Richter's recommendation for "scarcity pricing" fees.

6

7 **Q17. Does this conclude your rebuttal testimony?**

8 A17. Yes, it does.

MR. JANISZEWSKI: Thank you, your Honor.

Next, the Company moves to bind into the record the Qualifications and Direct Testimony of Aaron Willis consisting of a cover sheet and 11 pages of questions and answers. The Company also moves for the admission of two direct exhibits sponsored by Witness Willis labeled as Exhibit A-19 and Exhibit A-20. The Company also moves to bind into the record the Rebuttal Testimony of Aaron Willis, consisting of a cover sheet and 13 pages of questions and answers, and Mr. Willis did not sponsor any exhibits with his rebuttal testimony.

JUDGE STALEY: All right. Is there any objection to the binding in of the prefiled Direct and Rebuttal Testimony of Aaron Willis, or the admission of Exhibits A-19 and A-20?

Hearing none, the prefiled Direct and Rebuttal Testimony of Aaron Willis are bound into the record, and Exhibits A-19 and A-20 are admitted into evidence.

(Direct Testimony and Rebuttal Testimony bound in.)

- - -

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of)
DTE ELECTRIC COMPANY)
for Approval of Special Contracts)
and for other relief)

Case No. U-22058

QUALIFICATIONS
AND
DIRECT TESTIMONY
OF
AARON WILLIS

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF AARON WILLIS

Line
No.

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

2 A1. My name is Aaron Willis (he/him/his). My business address is One Energy Plaza,
3 Detroit, Michigan 48226. I am employed by DTE Energy Corporate Services, LLC,
4 a subsidiary of DTE Energy Company (DTE Energy), as Director, Regulatory
5 Affairs.

6

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

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

9

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

11 A3. I received a Bachelor of Arts in Political Science from the University of Michigan,
12 a Master's in Environmental Management from the Yale School of Forestry and
13 Environmental Studies, and a Master's in Business Administration from the
14 University of Maryland.

15

16 **Q4. What is your work experience?**

17 A4. In 2009, I was employed by the US Army Corps of Engineers, Institute for Water
18 Resources as Social Scientist supporting enforcement of the Clean Water Act and
19 engagement with domestic and international partners on a variety of water
20 resources issues. In 2015, I was employed by Booz Allen Hamilton in their energy
21 practice, providing support to commercial and federal clients on a variety of energy
22 matters.

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1 In 2017, I began my employment with DTE Energy as an Associate in Corporate
2 Strategy. In this role, I supported key operational and strategic work across the
3 Company. I was promoted to Senior Associate in 2019 and transitioned to
4 Corporate Development, where I supported the Company's financial strategy. In
5 2020, I accepted a position in Regulatory Affairs supporting the Company's state
6 regulatory strategy and engagement with the Michigan Public Service Commission
7 (MPSC or Commission), MPSC Staff, and Michigan energy stakeholders. In 2021,
8 I became Manager, Regulatory Economics, with responsibilities including the
9 management of regulatory activities relative to DTE Electric's rate strategy,
10 pricing, and load research. In 2024, I was promoted to Director, Regulatory Affairs.

11

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

13 A5. My responsibilities include the management of regulatory activities relative to DTE
14 Electric's rate strategy, regulatory mechanisms, pricing, revenue requirements, cost
15 of service, and load research.

16

17 **Q6. Have you previously sponsored testimony before the Michigan Public Service**
18 **Commission?**

19 A6. Yes. I have sponsored testimony in the following cases:

- 20 • U-21163 XL High Load Factor Rate
- 21 • U-20836 DTE Electric 2022 General Rate Case
- 22 • U-21193 DTE Electric 2022 Integrated Resource Plan
- 23 • U-21306 Rider No. 16 Transition
- 24 • U-21338 DTE Electric 2023 Securitization
- 25 • U-21297 DTE Electric 2023 General Rate Case

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1	• U-18091	DTE Electric 2024 PURPA Case
2	• U-21534	DTE Electric 2024 General Rate Case
3	• U-21860	DTE Electric 2025 General Rate Case
4	• U-21909	DTE Electric Performance Based Ratemaking Mechanism

Line
No.

1 **Purpose of Testimony**

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

3 A7. The purpose of my testimony is to describe the customer benefit generated by the
4 contracts executed between the Company and Google LLC (the Customer) and
5 explained by Witness Foley. I will explain the Company's methodology for
6 calculating customer benefit and the input information used in the calculation.

7

8 **Q8. Are you sponsoring any exhibits in this proceeding?**

9 A8. Yes. I am sponsoring the following exhibits:

- 10 • Exhibit A-19 – Customer Benefit
- 11 • Exhibit A-20 – Base Sales Benefit

12

13 **Q9. Is this transaction beneficial to all other customers?**

14 A9. Yes. Based on the Company's best information, this transaction is expected to
15 generate an estimated \$1.7 billion of benefit for other customers, clearing the
16 threshold established by the Commission in Case No. U-21859. The Commission's
17 November 6th, 2025, Order in that case set a test that Consumers Energy
18 "demonstrate[s] that costs caused by the interconnecting large load customer to be
19 served under the tariff are not being paid for by other customers". This testimony
20 demonstrates the Company's expectation of positive benefits for all other
21 customers, and that the combined revenues and avoided costs exceed the costs
22 cause by the Customer over the term of the contract. Said differently, costs will not
23 be paid by other customers.

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1 **Q10. What is the Company's approach to calculating customer benefits of the**
2 **special contracts?**

3 A10. The contracts described by Witness Foley each generate certain additional costs
4 and certain benefits (cost reductions or avoided costs) to other customers. For
5 example, the Primary Supply Agreement (PSA) results in additional sales that the
6 Customer is committing to bring to the system; these sales create downward
7 pressure on base rates. Similarly, the Clean Capacity Accelerator Agreement
8 (CCAA) governs how the Customer will directly support certain storage and
9 renewable assets as well as capacity contracts; the structure of the CCAA
10 (described by Witness Foley) generates additional benefits to other customers.
11 Future generation resources (modeled here using a Combined Cycle Gas Turbine
12 (CCGT) with Carbon Capture and Sequestration (CCS) as a proxy) introduce
13 additional costs.

14
15 The Company's objective in calculating the benefits of the contracts is to account
16 for 1) each category of benefit/cost such as those above, and 2) model those cost
17 changes using applicable regulatory structures and processes. The sum of the
18 inputs, including beneficial inputs such as the impact of incremental sales and
19 incremental costs such as new assets, reflects the net customer impact in each year.
20 The approach established by the Company to assess the Customer impact is
21 designed to capture all benefit and cost changes and utilize existing methods. The
22 net of this analysis is \$1.7 billion of estimated benefit to the Company's other
23 customers over the term of the PSA and CCAA.

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1 **Q11. How is the Company supporting the calculations appearing within Exhibit A-**
2 **19?**

3 A11. Each of the cost and benefit categories assessed by the Company has testimony and
4 quantitative support, which explain the calculations and the basis for them. Across
5 the Exhibit, negative values reflect benefits and positive values reflect costs.

6 • Base Sales Benefit – this is described below in my testimony and appears
7 on Line 2 of Exhibit A-19.

8 • Incremental Power Supply Cost Recovery (PSCR) – Witness Burgdorf
9 sponsors the estimated changes to PSCR costs from the addition of the
10 Customer’s load, including, for example, incremental transmission costs,
11 changes in PSCR sales, and renewable compliance. This also includes the
12 avoided cost of reducing 250 MW of renewable compliance build as
13 discussed by Witness Bilyeu. Using this information, Witness Burgdorf
14 develops net changes in power supply costs to customers. The net
15 (benefit)/cost is found on Line 4 of Exhibit A-19.

16 • Other Non-Fuel and Purchased Power O&M – Witness Burgdorf sponsors
17 the modeled other O&M costs. These costs are found on Line 6 of Exhibit
18 A-19.

19 • Proxy CCGT Revenue Requirement – Witness Burgdorf sponsors the plant
20 capital and O&M cost assumptions and an associated revenue requirement.
21 This cost is found on Line 8 of Exhibit A-19

22 • CCS Revenue Requirement – Witness Burgdorf sponsors the CCS capital
23 and O&M cost assumptions and an associated revenue requirement,
24 including applicable tax credits. This cost is found on Line 10 of Exhibit A-
25 19

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- 1 • Benefit of Storage Pull Ahead – The CCAA¹ contract described by Witness
- 2 Foley includes up to 480 MW of storage being directly supported by the
- 3 Customer². As described by Witness Burgdorf's testimony in Section I, the
- 4 storage assets were removed from the base build plan, generating an
- 5 avoided cost benefit to existing customers. This benefit is found on Line 12
- 6 of Exhibit A-19.
- 7 • Total (Benefit)/Cost to Customers – This is the sum of the preceding items
- 8 and is found on Line 14 of Exhibit A-19.

9

10 **Q12. What are the total benefits of the special contracts?**

11 A12. The total benefit to other customers from the contracts is estimated to be \$1.7 billion

12 from 2028 through the conclusion of the contract in 2047. The detailed build up by

13 year can be found in Exhibit A-19. The total benefits by component over the

14 contract life is found on col (v) lines 2-12 and replicated below:

15	• Base Sales Benefit	\$4.85B benefit
16	• PSCR ³	\$2.31B benefit
17	• Other Non-F&PP O&M	\$0.02B cost
18	• Proxy CCGT	\$4.17B cost
19	• CCS direct cost	\$2.43B cost
20	• <u>Storage Pull Ahead</u>	<u>\$1.16B benefit</u>
21	• Total	\$1.70B benefit

¹ The CCAA payment structure is described by Witness Foley

² The Company modeled 450 MW of CCAA storage, however it may build up to 480 MW of storage under the CCAA. Incremental storage deployment beyond 450 MW would generate additional customer benefits.

³ This includes the avoided cost benefit of reducing renewable compliance build by 250 MW as described by Witnesses Bilyeu and Burgdorf

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1 **Q13. How did you calculate the “base sales benefit” in Exhibit A-20?**

2 A13. The base sales benefit utilizes the Company’s standard cost of service (COS) model
3 as approved in Case No. U-21534 (updated for additional sales as approved in Case
4 No. U-21990) and evaluates the impact of the Customer’s load. As utilized here,
5 the model output is the net change in the revenue deficiency (sufficiency). The
6 analysis incorporated the incremental revenues and incremental base power supply
7 expenses associated with serving the Customer —items typically addressed in an
8 electric rate case—without modifying any underlying COS methods or
9 assumptions. The analysis assumes the underlying load is at full ramp of 1000 MW
10 and a 90% load factor. The difference between the revenue deficiency (sufficiency)
11 calculated without the Customer load and the revenue deficiency calculated with
12 the Customer load represents the benefit to all customers. In this instance, the
13 calculation yields a revenue sufficiency – the addition of the load and additional
14 base power supply expenses yields a benefit to other customers.

15

16 **Q14. Does the base sales benefit include any changes to rate base or other costs?**

17 A14. No. Additional rate base costs, benefits, and other costs are identified separately in
18 Exhibit A-19.

19

20 **Q15. Is the method for calculating base sales consistent with how the Company**
21 **develops the revenue requirement within COS in rate cases?**

22 A15. Yes. First, I calculated the Customer’s present revenues, based on assumed Rate
23 Schedule D11 (transmission voltage) service, and the incremental base power
24 supply costs attributable to its load, consistent with the treatment such items would
25 receive in a rate case. Income taxes were then calculated on the incremental pretax

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1 net income, and the incremental income deficiency was grossed up using the
2 revenue multiplier approved in Case No. U-21534. The revenue multiplier is used
3 to convert between after-tax income deficiency/(sufficiency) and the pre-tax
4 revenue requirement. These results were incorporated into the COS model. To
5 complete the analysis, updates were made to (i) sales and present revenues by class,
6 (ii) customer counts where applicable, and (iii) load schedules such that the data
7 center's load is reflected in the production and distribution allocators. The COS
8 analysis then determined the updated revenue deficiency/(sufficiency). The
9 sufficiency is the difference with and without the incremental Customer load.

10

11 **Q16. Can you explain the results of the base sales analysis that you performed?**

12 A16. After incorporating the incremental revenues, base power supply expenses⁴, taxes,
13 and updated load schedules, the model was rerun to determine the revenue
14 deficiency/(sufficiency) with the Customer's load included. This value was then
15 compared to the revenue deficiency/(sufficiency) without the Customer's load. The
16 difference represents the modeled net benefit that would be realized in a rate case
17 cost of service study. A lower revenue deficiency (or higher sufficiency) in the
18 "with Customer" case indicates that the Customer's incremental revenues exceed
19 the incremental costs included in this COS analysis, resulting in a benefit that would
20 flow through to all customers in an electric rate case. The "Customer Study Results"
21 tab of Exhibit A-20 summarizes this calculation.

⁴ Consistent with the Company's standard rate case fuel and purchased power calculations and shown on tab "Adjust A-13 C4" of Exhibit A-20

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1 **Q17. How does the single year analysis account for the full contract period?**

2 A17. As described above, the COS is premised on the U-21534 Ordered COS. The
3 “Customer Study Results” tab, line 30, column (l) of Exhibit A-20 shows a
4 sufficiency (i.e. a net benefit) of \$194.7 million. This is assumed to be a 2025
5 nominal value. The values for years beyond 2026 are calculated as follows:

- 6 • 2026 and 2027 are excluded as the Customer will not be served in 2026 and
7 has de minimis load in 2027
- 8 • All years 2028 – 2047 assume an underlying growth of Rate Schedule D11
9 of 1.5%, compounding annually from a 2025 basis
- 10 • 2028 sales are estimated to be approximately 43% of the estimated full ramp
11 sales based on the Customer’s ramp schedule. This is found on line 33,
12 column (b) of the tab
- 13 • 2029 is the first year in which the Customer sales are assumed in full for the
14 calendar year. This is found on line 33, column (c) of the tab
- 15 • For all years beyond 2029, they are inflated at 1.5% with no other
16 adjustments

17

18 **Q18. Does the Customer provide benefit through the nuclear surcharge?**

19 A18. Yes. The nuclear surcharge revenue requirement approved in Case No. U-21534 is
20 \$40.1 million and is recovered volumetrically. Considering the additional Customer
21 sales, this generates a benefit of \$5.0 million per year (or \$2.4 million in 2028 at
22 lower sales). This is reflected in Exhibit A-20 on the “Customer Study Results” tab,
23 line 34.

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1 **Q19. How are incremental power supply costs considered in this analysis?**

2 A19. As described more extensively by Witness Burgdorf, there are various changes to
3 cost and load assumptions that occur within the PSCR process. These include the
4 addition of the Customer load when calculating the PSCR factor, and the
5 consideration of additional fuel and purchased power costs, renewable costs or
6 benefits, and transmission costs. The with and without calculation of the PSCR
7 factor is a critical input to understanding overall customer impacts. It appropriately
8 captures the incremental costs the Customer brings to the PSCR while accounting
9 for the benefits of spreading existing fixed costs (for transmission and renewable
10 build) across additional sales. Witness Burgdorf describes the specifics of the inputs
11 and calculations in his testimony.

12

13 **Q20. Does this conclude your testimony?**

14 A20. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of)
DTE ELECTRIC COMPANY)
for Approval of Special Contracts)
and for other relief)

Case No. U-22058

REBUTTAL TESTIMONY

OF

AARON WILLIS

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF AARON WILLIS

Line
No.

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

3 A1. My name is Aaron Willis (he/him/his). My business address is One Energy Plaza,
 4 Detroit, Michigan 48226. I am employed by DTE Energy Corporate Services, LLC,
 5 a subsidiary of DTE Energy Company (DTE Energy), as Director, Regulatory
 6 Affairs.

7

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

10 A2. Yes.

11

12 **Purpose of Testimony**

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

14 A3. The purpose of this rebuttal testimony is to respond to positions raised by several
 15 intervenors, including Michigan Public Service Commission (MPSC or
 16 Commission) Staff (Staff), Michigan Environmental Council/Natural Resources
 17 Defense Council/Sierra Club (MNS), and Association of Businesses Advocating
 18 for Tariff Equality (ABATE), in response to the Company's proposed special
 19 contracts with Google LLC ("Customer"). These include:

20 1. Staff Witness Isakson's discussion of cost of service, including the appropriate
 21 venue for cost of service and ratemaking as well as Staff's proposed requirement
 22 for future informational cost of service and rate design filing requirements with
 23 each subsequent customer.

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1 2. Staff Witness Isakson's proposal to apply in this case the allowance for
2 contribution in aid of construction (CIAC) as proposed in pending Case No. U-
3 22061.

4 3. MNS Witness Woods' proposal regarding distribution cost recovery

5 4. ABATE Witness Dauphinais' proposal for a separate rate class for the
6 Customer and other large customers

7 5. ABATE Witness Dauphinais' proposals regarding the Company's emergency
8 procedures and their applicability in this case
9

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

11 A4. No.
12

13 **Rebuttal of Staff Witness Isakson**

14 **Q5. What is Staff's perspective regarding the role of cost of services studies in this**
15 **proceeding and for large load customers in future proceedings?**

16 A5. Staff describes the cost-of-service studies provided by the Company which show a
17 net benefit to customers overall, and describes the role of income tax allocation on
18 distribution costs and distribution customers. Staff Witness Isakson's testimony
19 then discusses the impact of choice migration on overall net benefits. Staff's
20 recreation of the Company's filed Exhibit A-20 (base sales benefit of the Customer)
21 "matches the Company's finding on Exhibit A-20"¹.
22

23 Witness Isakson then describes the role of this proceeding vis-à-vis cost of service
24 changes, saying "Cost allocation issues associated with the Customer are more

¹ Direct testimony of Staff Witness Isakson, Pg 12, Ln 4

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1 appropriately addressed in the Company's general rate cases along with all other
2 utility costs and revenues"². Turning to future rate cases, Witness Isakson describes
3 the "six cost of service and rate design studies" required of the Company following
4 the December 2025 Order in Case No. U-21990, proposes an amendment to one of
5 the six studies, and then recommends the Company be required to perform all six
6 studies in the future. He says that the "Commission [should] require the Company
7 provide the six different COSSs and rate designs in its next rate case so that the
8 Commission may make a judgement on how to create fair rates for *all* customers"³
9 (emphasis original).

10

11 **Q6. How does Witness Isakson characterize the role of the integrated resource**
12 **plan (IRP) in defining the allocation of resource specific costs?**

13 A6. Staff introduces the concept that the IRP is a viable venue for discussion of the
14 allocation of incremental resources. Witness Isakson says "In the Company's next
15 and subsequent IRPs, the Commission should consider how to eventually assign
16 production costs to the Customer, or to the Customers' rate class if it is separated,
17 so that any marginal cost of new capacity resources will not be passed on to other
18 customers unfairly."⁴

19

20 **Q7. Does the Company agree with Witness Isakson that any discussion of cost of**
21 **service or changes to allocations should occur in a rate case?**

22 A7. Yes. Witness Isakson correctly highlights that cost allocation and rate design issues
23 are a matter for general rate cases in the context of the Company's full costs and

² Direct testimony of Staff Witness Isakson, Pg 13, Lns 4-6

³ Direct testimony of Staff Witness Isakson, Pg 17, Lns 7-9

⁴ Id, Pg 29, Lns 7-10

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1 revenues, and not a matter for proceedings to approve special contracts, such as this
2 case. The Company concurs with this perspective and it is consistent with the
3 Commission's Order in the Company's prior request for special contract approval
4 in Case No. U-21990⁵.

5

6 **Q8. Does the Company agree with Witness Isakson that cost allocation should be**
7 **considered in an IRP?**

8 A8. No, the Company does not agree that such decisions can be fully addressed in an
9 IRP. The Company, in this case (see the direct case generally and the rebuttal
10 testimony of Company Witness Foley specifically), agrees that some type of
11 tracking of resources and costs triggered by the Customer is prudent. The IRP will
12 serve as the basis for understanding the change in resource mix as a result of serving
13 the Customer's load, however the IRP is not the appropriate venue to determine
14 how to recover those costs. As Witness Isakson remarks, "Costs are not allocated
15 nor is revenue collected via IRP proceedings⁶" and the Company fully agrees.
16 There is simply not the right information in an IRP, nor is it the purpose of the IRP,
17 to facilitate that assessment. As such, the Company recommends that any
18 exploration of cost allocation or cost assignment be addressed in a rate case and not
19 in an IRP.

20

21 **Q9. Does the Company agree with Staff Isakson's suggestion that the "six cost of**
22 **service and rate design studies" be provided annually?**

23 A9. The Company believes that this cadence and timing should be considered in a
24 general rate case rather than in this proceeding. In its pending general rate case

⁵ December 18, 2025 Order in Case No. U-21990, Pg 38

⁶ Id, Pg 29, Lns 10-11

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(Case No. U-22046), the Company developed and submitted the original six studies as required by the December 2025 Order in Case No. U-21990 and described by Witness Isakson. These six studies include both Oracle load and the Customer load at issue in this case assuming their full load ramp is online. The Company is supportive of Witness Isakson's view that rates remain fair for all customers, however, this special contract case is not the correct forum to establish a longer term study requirement that is generic to all large load customers. The Company recommends the Commission consider this proposal in a rate case and not in this narrow proceeding for the following reasons:

- *The discussion of the currently available studies in Case No. U-22046 should be completed before determining any future study requirements.* It may be that following the conclusion of Case No. U-22046 there are targeted or specific areas of continued exploration and investigation the Commission finds important. Similar to Witness Isakson's observation that cost of service should be addressed in rate cases and not in special contract cases, so too should the cost-of-service discussion in the pending rate case be allowed to resolve before determining what, if any, next steps are appropriate. The Company notes that the studies currently available in Case No. U-22046 align with Witness Isakson's proposed change to Study #6 and directly allocate costs to individual large load customers.

- *Continued burden on rate cases.* The Commission in Case No. U-21637 observed the ever-growing size and complexity of rate cases. These studies represent a substantial additional burden of work for all parties to the case. As filed in Case No. U-22046, they include many pages of direct testimony

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1 and more than 500 pages of direct exhibits, both of which are certain to
2 grow when intervenor testimony and exhibits, rebuttal testimony and
3 exhibits, and briefs are included. Rather than an ongoing requirement to
4 submit these voluminous studies, the need to do so would be best weighed
5 in a rate case, and not in this more narrow proceeding.

6

7 **Q10. What does Staff propose with respect to distribution cost recovery and the**
8 **pending CIAC proposal in Case No. U-22061?**

9 A10. In Case No. U-22061, the Company filed its proposed large load provision for Rate
10 Schedule D11, consistent with the December 2025 Order in Case No. U-21990.
11 One of the terms proposed by the Company in that case was a modified approach
12 to calculating credits for CIAC for any customer subject to the proposed large load
13 provision. In this context, Staff proposes that the CIAC allowance proposal in Case
14 No. U-22061 be retroactively applied to the Customer should it be approved.
15 Witness Isakson's testimony states:

16 "...that if the Commission approves the proposed tariff in Case U-22061
17 with a CIAC provision, then that same standard should be applied to the
18 Customer for costs beyond the \$50M identified in the line extension
19 agreement. For example, if infrastructure costs exceed \$50M by less than
20 2-years of distribution revenue then those costs should be included for
21 recovery in future rate cases, but the Customer should be responsible for
22 any costs over the CIAC allowance approved for the LLP."⁷

23

⁷ Staff Isakson Direct Pg 18 Lns 13-18

Line
No.

1 Staff then calculates the CIAC allowance associated with the Case No. U-22061
2 proposal as ~\$30 million.

3

4 **Q11. Does the Company believe that the CIAC proposal in the large load provision**
5 **proceeding is applicable to the Customer?**

6 A11. No. As described below, the Customer has already agreed to fund investments
7 beyond what the currently approved rate book requires, and it is not appropriate to
8 retroactively apply tariffs to prior contracts or requests.

9

10 • *The customer has already agreed to fund distribution investments beyond*
11 *rate book requirements.* The currently approved DTE Electric Rate Book
12 for Electric Service describes the CIAC allowance to customers larger than
13 1000 kW on sheet C-30.00. For a D11 customer of this size, the maximum
14 allowance is approximately \$550⁸. The Customer has agreed to fund the
15 first \$50 million of Customer-caused distribution costs in addition to
16 building and owning their own substation. Given the Company's estimated
17 cost of associated distribution work of less than \$50 million, the expectation
18 is that all distribution costs caused by the Customer will be paid for by the
19 Customer. Thus, the Company and the Customer agreed to terms that
20 require the Customer to fund work that would ordinarily be provided by the
21 Company at no cost to the connecting customer.

22

23 • *Retroactive tariff application is not appropriate.* The Power Supply
24 Agreement (PSA) with the Customer was executed on March 13, 2026, and
25 filed for approval before the Commission on March 17, 2026. The proposals

⁸ See direct testimony of Company Witness Benyard, Pg 7, Ln 13

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1 in Case No. U-22061 were not approved by the Commission (nor tariffs
2 commensurately updated) at the time of contract execution with the
3 Customer nor at the time of filing this case. They remain pending before the
4 Commission and the expected Order date is sometime in 2027⁹, potentially
5 a year after execution of the Customer PSA.

6

7 While rates may and do change from time to time based on Commission Orders,
8 and customers are subject to them, neither customers generally nor this Customer
9 specifically should be subject to retroactive application of tariffs. Tariffs function
10 to describe the responsibilities of customers and the Company in the provision of
11 electric service on a prospective basis; neither party can make informed decisions
12 if the basic framework of the transaction is subject to retroactive changes. A clear
13 example of this is the elimination of new master metered multi-unit residential
14 dwellings in 1978 – a change made on a prospective basis but without retroactive
15 application, even though concerns about then-existing master metered buildings
16 gave rise to the Commission order¹⁰. Retroactive tariff application would open
17 current and future customers to future risk, responsibility, or, as in case with CIAC
18 allowances, financial liability. As such, it is inappropriate to change CIAC policy
19 for this customer on a retroactive basis and the Commission should reject the
20 proposal.

21

22 **Rebuttal of MNS Witness Woods**

23 **Q12. What does MNS Witness Woods discuss and propose regarding distribution**
24 **cost recovery?**

⁹ Scheduling Memo issued on April 28, 2026, in Case No. U-22061 [Microsoft Word - U22061.042826](#)

¹⁰ September 28, 1978 Order in Case No. U-5502

Line
No.

1 A12. MNS Witness Woods describes the Company's expected distribution costs and the
2 Line Extension Agreement (LEA) with the Customer, stating that under the LEA
3 the Customer has agreed to pay up to \$50 million toward the Company's
4 infrastructure upgrade costs at its facility and that the Company's current estimate
5 of those costs is \$29.1 million to \$44.3 million. She additionally states that "I am
6 concerned that there is only \$5.7 million of headroom between the top of the range
7 and the Company's own cap on infrastructure costs: the point past which other
8 customers will start to foot the bill."¹¹

9
10 She then recommends that the "Commission condition any approval of the Special
11 Contracts on Google paying all electric infrastructure costs required to connect
12 Google's data center without any cap and prohibit DTE from recovering any of
13 these costs from non-data center customers."¹²

14
15 **Q13. Does Witness Woods provide any justification for her recommendation?**

16 A13. No, the only apparent justification is that "there is only \$5.7 million of headroom
17 between the top of the range" and the Customer's contribution towards the costs.
18 She does not consider that her recommendation conflicts with currently approved
19 CIAC policy and offers no justification for why a change in policy is appropriate
20 through this special contract proceeding. Specifically, under the current CIAC
21 policy, the Customer would not be directly responsible for any distribution upgrade
22 costs since their CIAC Allowance would be greater than the cost of the upgrades.
23 Instead, absent the special contract, those costs would be added to the Company's
24 rate base and recovered through base rates. Said differently, the Customer agreeing

¹¹ Testimony of MNS Witness Woods, Pg 14

¹² Id Pg 37

Line
No.

1 to pay up to \$50 million toward infrastructure upgrade costs represents an
2 incremental benefit to the Company's other customers that they would not
3 otherwise realize under current CIAC policy.

4

5 As such, the Company recommends that the Commission reject this proposal, and
6 highlights that prospective large load customer CIAC policy is being addressed in
7 pending Case No. U-22061.

8

9 **Rebuttal of ABATE Witness Dauphinais**

10 **Q14. What does ABATE Witness Dauphinais propose with respect to cost of service**
11 **and "intra-class subsidies"?**

12 A14. Witness Dauphinais describes the relative size of the Customer load compared to
13 the existing D11 total demand and energy (also included are the same comparisons
14 for Oracle, which is not germane to this proceeding). Based on the comparison of
15 incremental demand and energy added to D11, he asserts "As a result, placing
16 Google (and Oracle) into the D11 customer class will overwhelm the current load
17 characteristics of the traditional commercial and industrial customers of the D11
18 customer class. This is highly likely to cause large subsidies between the members
19 of the class given rate design does not necessarily fully align with cost allocation
20 in class cost of service studies."¹³ He then suggests a "significant possibility" that
21 data center specific costs will be allocated to D11 at some point in the future.

22

23 From this ABATE proposes "a new rate class can be readily established for Google
24 and the other large data center loads that initially utilizes the same rates as the Rate

¹³ Direct testimony of ABATE Witness Dauphinais Pp 27-28, Lns 15 - 1

Line
No.

1 D11 class. This would produce the same outcome as initially placing these loads on
2 Rate D11 at the outset of service without introducing any risk of intra-class
3 subsidies to the existing members of the Rate D11 class.”¹⁴
4

5 **Q15. Is this case the appropriate venue for a substantive discussion of, or changes**
6 **to, cost of service and rate design?**

7 A15. No. The Commission addressed the question of venue for cost of service and rate
8 design in the December 2025 Order in Case No. U-21990, saying in part “However,
9 should it be shown in a future rate case that any particular rate class does not benefit
10 from a reduction to the cost of service, it is the rate case that is the proper forum for
11 ratemaking.”¹⁵ And as described by Staff Witness Isakson, “Cost allocation issues
12 associated with the Customer are more appropriately addressed in the Company’s
13 general rate cases along with all other utility costs and revenues”¹⁶. Moreover, the
14 Company’s currently pending general rate case includes several cost of service and
15 rate design studies intended to facilitate discussion of this very question.
16

17 As such, the Company recommends the Commission find consistent with the Order
18 in Case No. U-21990 and the Staff’s position in this case that discussion of, or
19 changes to, cost of service or rate design is appropriately addressed in a general rate
20 case and not in a special contract proceeding.
21

22 **Q16. What does ABATE Witness Dauphinais recommend regarding the**
23 **Company’s Emergency Procedures?**

¹⁴ Id Pg 28, Lns 10-14

¹⁵ December 18, 2025 Order in Case No. U-21990, Pg 38

¹⁶ Direct testimony of Staff Witness Isakson, Pg 13, Lns 4-6

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1 A16. Witness Dauphinais describes the Company's filing in Case No. U-22059, which
2 is a compliance filing in response to the December 2025 Order in Case No. U-
3 21990. Regarding that filing, he believes it should have "only been filed to apply
4 to Oracle and there is a real possibility that the Commission will reject DTE's
5 application in that proceeding"¹⁷. The testimony continues and acknowledges that
6 the Customer should be subject to similar load shedding requirements as those
7 described in the U-22059 filing.

8

9 The concluding recommendation is that the Commission should order the Company
10 to "[modify] its emergency procedures to subject Google to firm load shedding
11 prior to other customers, provided that such customer load shedding does not: (i)
12 compromise system reliability; and (ii) can prevent shedding firm load of other
13 DTE Electric Customers, until such time all of the resources necessary to serve the
14 Google data center load are in service."¹⁸

15

16 **Q17. What is the Company's perspective regarding the Emergency Procedures and**
17 **load shedding requirements for the Customer?**

18 A17. The Company highlights that its filed Emergency Procedures in Case No. U-22059
19 will apply to the Customer based on the Customer's expected load of more than
20 500 MW. The requirement for the Customer to shed load under the circumstances
21 described in the Emergency Procedures is consistent with ABATE's
22 recommendations on the topic as described above and it is not evident to the
23 Company what alternative, if any, is being proposed by ABATE. Should ABATE's
24 proposal be to include the Customer by name in the tariff, the Commission should

¹⁷ Direct testimony of ABATE Witness Dauphinais Pg 25, Lns 17-19

¹⁸ Ibid, Pg 26, Lns 21-25

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1 reject that recommendation. Tariffs establish criteria that are generally applicable
2 to those customers who meet the criteria and it would be highly unusual at best, and
3 without precedent, to describe the obligations of an individual customer by name
4 in the Company's tariffs. Such an approach would establish a requirement to amend
5 the tariff each time a new customer is ordered by the Commission to be subject to
6 it – an approach that is misaligned with the fundamental purpose of a tariff.

7

8 The Company is aware that ABATE provided comments in Case No. U-22059 and
9 to the extent ABATE has considerations or concerns to raise with the Commission
10 in that case, that docket is the appropriate venue.

11

12 **Q18. Does this conclude your rebuttal testimony?**

13 A18. Yes, it does.

MR. JANISZEWSKI: Thank you, your Honor.

DTE Electric moves to bind into the record the Qualifications and Direct Testimony of Justin J.W. Brooks consisting of a cover sheet and ten pages of questions and answers. The Company also moves for the admission of the following two direct exhibits sponsored by Witness Brooks labeled as Exhibit A-3 and Exhibit A-4. There are no changes to Witness Brooks' direct testimony or direct exhibits, and Mr. Brooks did not sponsor any rebuttal testimony.

JUDGE STALEY: Thank you. Is there any objection to the binding in of the prefiled Direct Testimony of Justin J.W. Brooks or the admission of Exhibits A-3 and A-4?

Hearing none, the prefiled Direct Testimony of Justin J.W. Brooks is bound into the record, and Exhibits A-3 and A-4 are admitted into evidence.

(Direct Testimony bound in.)

- - -

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of)
DTE ELECTRIC COMPANY)
for Approval of Special Contracts)
and for other relief)

Case No. U-22058

QUALIFICATIONS
AND
DIRECT TESTIMONY
OF
JUSTIN J. W. BROOKS

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF JUSTIN J. W. BROOKS

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

2 A1. My name is Justin Jeffrey Whitaker Brooks. My business address is: 3000
3 Riverchase Galleria, Suite 3 575, Hoover, AL 35244. I am employed by
4 PowerGEM, as a Project Lead. PowerGEM is a software and consulting firm that
5 provides expertise in numerous areas including resource planning and resource
6 adequacy to utilities across the United States.

7

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

9 A2. I am testifying on behalf of DTE Electric Company (DTE Electric or the Company).
10

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

12 A3. I graduated from North Carolina State University with a Bachelor of Science in
13 Nuclear Engineering. In addition, I received a Master of Science from Virginia
14 Commonwealth University in Mechanical and Nuclear Engineering.

15

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

17 A4. In 2012, I joined Newport News Shipbuilding where I performed various duties
18 across numerous naval platforms related to radiation shielding and the safe
19 engineering and conduct of radiological work. In 2017, I joined the Naval Nuclear
20 Laboratory where I performed various duties related to the engineering of safety
21 systems in support of the Naval Nuclear Propulsion Program. In 2019, I joined
22 Duke Energy where I developed and led the in-house resource adequacy analysis
23 program for all three company jurisdictions using PowerGEM's Strategic Energy
24 and Risk Valuation Model (SERVM). In this role, I conducted analysis in support

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1 of the 2021, 2022, and 2023 Duke Energy Carolinas and Duke Energy Progress
2 Integrated Resource Plans for North and South Carolina.

3

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

6 A5. I am a registered professional engineer in North Carolina.

7

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

9 A6. As a Project Lead with PowerGEM, I am responsible for managing the SERVUM
10 product and both managing and conducting resource adequacy studies for utility
11 clients.

12

13 **Q7. Have you previously sponsored testimony before the Michigan Public Service**
14 **Commission (MPSC)?**

15 A7. No. I have not appeared before the MPSC.

16

17 **Q8. Please provide a summary of your and your firm's expertise in performing**
18 **this type of analysis.**

19 A8. I have performed and supervised resource adequacy and capacity accreditation
20 studies for various clients over the past six years both with Duke Energy and
21 PowerGEM. In addition, I have been involved with various industry task groups
22 such as the Electric Power Research Institute's "Resource Adequacy for a
23 Decarbonized Future" project, Energy Systems Integration Group's "Redefining
24 Resource Adequacy" taskforce, the SERC Reliability Corporation's Resource
25 Adequacy Working Group, and the North American Electric Reliability

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1 Corporation Probabilistic Assessment Working Group. PowerGEM¹ has
2 performed resource adequacy and capacity accreditation analysis for various
3 entities across the country for over 20 years. A non-exhaustive list includes utilities
4 such as the Company, Ameren, Associated Electric Cooperative, Central Louisiana
5 Electric Co-Op, Dominion Energy South Carolina, Duke Energy Carolinas, Duke
6 Energy Progress, Entergy, Georgia System Operations Corporation, Louisville Gas
7 & Electric, Santee Cooper, Southern Company, and the Tennessee Valley
8 Authority. Some of the Independent System Operator and Regional Transmission
9 Organizations include Alberta Electric System Operator (AESO), Electric
10 Reliability Council of Texas (ERCOT), Midwest Independent System Operator
11 (MISO), and the Southwest Power Pool (SPP).

¹ PowerGEM acquired Astrapé Consulting in 2024

Line
No.

1 **Purpose of Testimony**

2 **Q9. What is the purpose of your testimony?**

3 A9. The purpose of my testimony is to explain the results of the resource adequacy
4 analysis performed at the Company's request in years 2029 and 2033 to support the
5 addition of the Customer's (Google LLC) load to the DTE Electric system.

6

7 **Q10. Are you sponsoring any exhibits in this proceeding?**

8 A10. Yes. I am sponsoring the following exhibits:

9	<u>Exhibit</u>	<u>Description</u>
10	A-3	Justin Brooks Curriculum Vitale
11	A-4	DTE Electric Resource Adequacy Analysis

12

13 **Q11. Were these exhibits prepared by you or under your direction?**

14 A11. Yes, they were.

15

16 **Resource Adequacy Analysis**

17 **Q12. What is resource adequacy?**

18 A12. Resource adequacy is the ability of the electric system to meet the energy needs of
19 electricity consumers. This means having sufficient resources to meet projected
20 electric demand².

21

22 **Q13. How does MISO ensure resource adequacy requirements?**

23 A13. MISO, under its Federal Energy Regulatory Commission (FERC) approved tariff,
24 has resource adequacy requirements to ensure adequate resources are available to

² <https://www.ferc.gov/reliability-explainer>

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1 meet demand. Load Serving Entities must comply with the MISO resource
2 adequacy requirements.

3

4 **Q14. How does the Company demonstrate resource adequacy per the MISO tariff?**

5 A14. MISO establishes a Planning Reserve Margin (PRM), which is defined as the
6 amount of capacity above the expected weather-normalized peak demand necessary
7 to meet the electric industry's commonly used criteria of potentially experiencing
8 a single day containing at least one hour with firm load shed every ten years. The
9 PRM is added to the Company's coincident peak demand to calculate its Planning
10 Reserve Margin Requirements (PRMR). The Company demonstrates resource
11 adequacy by ensuring it has adequate resources to meet or exceed the PRMR.

12

13 **Q15. How will the Customer's load impact the Company's PRMR?**

14 A15. The Customer's load will increase the Company's PRMR. As the Customer's load
15 increases to the max load of approximately 1 GW, the Company's coincident peak
16 demand and PRMR will also increase.

17

18 **Q16. How will the Company meet the increased PRMR?**

19 A16. The Company will meet the increased PRMR through the deployment of zonal
20 resource credits (ZRC), renewable resources and energy storage under the Clean
21 Capacity Accelerator Agreement (CCAA), as well as demand response as
22 described by Witness Burgdorf. Adding additional capacity resources ensures
23 that the Company will have sufficient capacity to meet MISO's resource
24 adequacy requirements.

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1 **Q17. How does the resource adequacy study you performed differ from how the**
2 **PRMR is determined?**

3 A17. The resource adequacy study that I performed is designed to evaluate whether the
4 output of the complex capacity expansion modeling process meets the specified
5 level of resource adequacy. To do this, I evaluated the DTE Electric system using
6 PowerGEM's SERVIM.

7
8 **Q18. What metric is used to evaluate whether a resource portfolio is resource**
9 **adequate?**

10 A18. The standard metric used to evaluate resource adequacy of a resource portfolio is
11 Loss of Load Expectation (LOLE).

12

13 **Q19. What is LOLE?**

14 A19. LOLE is the expected number of days in a year when the utility will not have
15 enough energy from its resources to meet load and will have a firm load shed event.
16 It is the most commonly used resource adequacy criteria in the United States. The
17 Company's threshold for LOLE is specified by MISO Tariff Module E-1³ to be one
18 day with one or more hours of firm load shed every ten years due to a shortage of
19 generation capacity. This is more commonly referred to as either 0.1 LOLE or "one
20 day in ten".

21

22 **Q20. Can you describe the differences between capacity expansion modeling and**
23 **resource adequacy modeling?**

³ https://docs.misoenergy.org/miso12-legalcontent/Module_E-1_-_Resource_Adequacy.pdf

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1 A20. Capacity expansion modeling and resource adequacy modeling serve different but
2 complementary purposes in long-term planning. Capacity expansion modeling is a
3 deterministic analysis that identifies least-cost portfolios to meet a utility's
4 forecasted peak demand plus the required PRM over long term time horizons.
5 Capacity expansion modeling typically assumes normal weather conditions,
6 expected load growth and average generator performance. Because it is designed
7 to optimize under normal conditions, capacity expansion modeling does not capture
8 operational risks that occur in high impact, low probability events.
9
10 Resource adequacy modeling, on the other hand, is a probabilistic type of analysis.
11 Using the SERVVM tool, it stochastically stress tests the proposed resource
12 portfolios from the capacity expansion model in future study years to ensure that
13 the portfolios will meet the resource adequacy criteria, which in this analysis is 0.1
14 LOLE. SERVVM generates a large distribution of future scenarios to ensure a
15 representative sample from which to assess whether the DTE Electric system is
16 adequate. This type of modeling incorporates variations and risks such as:
17 (1) Extreme weather and its impact on both load and resources
18 (2) Economic load forecast uncertainty
19 (3) Generator performance uncertainty
20
21 Additionally, resource adequacy modeling is highly data and computing intensive,
22 running it every year throughout a long study horizon would be time-consuming and
23 provide limited incremental value. The best practice is to focus on key years defined
24 by major changes in the load and/or generation fleet.

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1 **Q21. Can you describe the SERVIM Model used in the resource adequacy analysis?**

2 A21. Yes. SERVIM is a production cost model designed to analyze the capabilities of an
3 electric system during a variety of conditions over thousands of scenarios. It
4 chronologically simulates the economic commitment and dispatch of a system
5 calculating economic and reliability metrics for each scenario.

6

7 **Q22. Can you describe the framework for the resource adequacy analysis you**
8 **performed?**

9 A22. Yes. The Company requested evaluation of two key study years 2029 and 2033, as
10 described by Witness Burgdorf. As part of the evaluation, MISO Local Resource
11 Zones (LRZs) 1, 2, 3, 4, 5, 6, and the non-Company portion of LRZ7 were included
12 in the analysis in addition to the DTE Electric system. For this analysis, I evaluated
13 the DTE Electric system against weather from 1980 through 2023, five levels of
14 economic load forecast uncertainty (-4%, -2%, 0%, 2%, and 4%), and fifty
15 stochastic evaluations of generator performance. All told, 11,000 yearly scenarios,
16 at an hourly resolution, were evaluated for each portfolio, for each study year. The
17 resulting probabilistic weighted average, or expected value, is the “final” result of
18 the analysis.

19

20 **Q23. What is the result of the 2029 resource adequacy analysis?**

21 A23. As shown in Exhibit A-4, assuming the resources included in the CCAA as well as
22 demand response in 2029 as discussed by Witness Burgdorf, the plan is resource
23 adequate with a LOLE of 0.102 event-day per year.

24

25 **Q24. What was your approach for modeling resources in 2033?**

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1 A24. I evaluated the DTE Electric system as provided by the Company with the DR and
2 ZRCs expiring by June 1, 2033.

3

4 **Q25. What is the result of the 2033 resource adequacy analysis?**

5 A25. This produced a LOLE for the Company of 0.238 event-day per year which does
6 not meet the 0.1 threshold (Exhibit A-4). To address this deficit, perfect capacity
7 was added until the system reached 0.1 event-day per year LOLE.

8

9 **Q26. What is the definition of “perfect capacity” and what did the SERV**
10 **modeling identify as the perfect capacity need?**

11 A26. Perfect capacity (sometimes referred to as PCAP) is defined as capacity with no
12 outages. Perfect capacity helps planners compare very different technologies on a
13 common basis, determine how much new capacity is needed to maintain resource
14 adequacy (such as 0.1 LOLE), and understand how resource mixes affect the
15 probability of outages. The modeling identified a need of 677 MW of perfect
16 capacity to bring the DTE Electric system back to 0.1 event-day per year LOLE.

17

18 **Q27. Did the Company revise their proposed plan to account for this inadequacy?**

19 A27. Yes. The Company provided a revised build plan that contained additional capacity
20 as described by Witness Burgdorf. This revised build plan was then evaluated in
21 SERV.

22

23 **Q28. What was the result of the 2033 resource adequacy analysis with the revised**
24 **build plan?**

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- 1 A28. The Companies revised build plan is resource adequate with a LOLE of 0.093
2 event-day per year (Exhibit A-4).
3
4 **Q29. Does this complete your direct testimony?**
5 A29. Yes.

1 MR. JANISZEWSKI: Thank you, your Honor.
2 The Company moves to bind into the record the
3 Qualifications and Direct Testimony of Steven N. Benyard
4 consisting of a cover sheet and seven pages of questions
5 and answers. The Company also moves for the admission of
6 the direct exhibit sponsored by Witness Benyard
7 designated as Confidential Exhibit A-1. Next, DTE
8 Electric moves to bind into the record Rebuttal Testimony
9 of Steven N. Benyard, consisting of a cover sheet and
10 five pages of questions and answers. Lastly, the Company
11 also moves for the admission of the rebuttal exhibit
12 sponsored by Witness Benyard and designated as
13 Confidential Exhibit A-21.

14 JUDGE STALEY: All right. Very quick
15 question for you, Mr. Janiszewski. Is Mr. Benyard's
16 direct testimony confidential?

17 MR. JANISZEWSKI: No, I don't believe so.
18 All my notes indicate otherwise. Just confirming.

19 JUDGE STALEY: I just thought I saw like
20 a chart that had a little blackout in it, but I don't
21 remember.

22 MR. JANISZEWSKI: No, there is no
23 confidential designation.

24 JUDGE STALEY: All right. Thank you. Is
25 there any objection to the binding in of the prefiled

1 Direct and Rebuttal Testimony of Steven N. Benyard, or
2 the admission of Confidential Exhibit A-1 and
3 Confidential Exhibit A-21?

4 Hearing none, the prefiled Direct and
5 Rebuttal Testimony of Steven N. Benyard are bound into
6 the record, and Confidential Exhibit A-1 and Confidential
7 Exhibit A-21 are admitted into evidence.

8 (Direct Testimony and Rebuttal Testimony bound in.)

9 - - -

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of)
DTE ELECTRIC COMPANY)
for Approval of Special Contracts)
and for other relief)

Case No. U-22058

QUALIFICATIONS
AND
DIRECT TESTIMONY
OF
STEVEN N. BENYARD

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF STEVEN N. BENYARD

Line
No.

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

2 A1. My name is Steven Benyard. My business address is: One Energy Plaza, Detroit,
3 Michigan 48226. I am employed by DTE Energy Corporate Services LLC, a
4 subsidiary of DTE Energy Company (DTE).

5

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

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

8

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

10 A3. I received a bachelor's degree in electrical engineering from Florida International
11 University and a Master of Business Administration from Nova Southeastern
12 University's Huizenga College of Business and Entrepreneurship.

13

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

15 A4. I have over two decades of experience leading various areas of operations including
16 transmission, substation and distribution, project management, along with
17 engineering functions that included reliability performance. Prior to my
18 employment with the Company, I served in various distribution leadership
19 positions at NextEra Energy for approximately 15 years, which included: General
20 Manager of Major Projects and Construction Services, Area Manager, Operations
21 Leader, Production Lead, Resource Lead, and Sr. Project Manager. After accepting
22 a position with Entergy New Orleans (ENO), from February 2021 to June 2022, I
23 served as Director of Distribution Operations, where I was responsible for the
24 operation and maintenance of the distribution systems. From June to October 2022,
25 I served as ENO's Director of Reliability, where I continued to be responsible for

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1 ENO's distribution system with the addition of the substation grid portfolio across
2 the ENO footprint. In 2022, I was promoted to Vice President, Reliability
3 (Transmission, Substation, and Distribution) for Entergy Louisiana, including New
4 Orleans. In 2024, I joined DTE in my current role as Vice President of Distribution
5 Operations Capital Delivery.

6

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

9 A5. I am a Certified Project Management Professional, and I have a Six Sigma Green
10 Belt.

11

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

13 A6. As Vice President of Distribution Operations Capital Delivery, I am responsible for
14 the execution of DTE Electric's major capital investments in alignment with the
15 Company's distribution grid plan. This responsibility encompasses resource
16 coordination, collaboration with communities and contract partners, adherence to
17 schedules, and monitoring of capital investment performance.

18

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

21 A7. No, although I have participated in regulatory proceedings before the Louisiana
22 Public Service Commission. Specifically, I sponsored the testimony in:

23 • Case No. U-36959 for Entergy Louisiana, LLC

Line
No.

1 **Purpose of Testimony**

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

3 A8. As described by Witness Foley, Google LLC (the Customer) is seeking to build a
4 data center and connect 1 GW of new load to the Company's electric system. The
5 data center will be located in Van Buren Township, Michigan, which is within DTE
6 Electric's service territory. DTE Electric plans to supply the Customer service at
7 transmission voltage levels (345KV), which the Customer will receive in each of
8 their two self-build substations and modulate to meet their needs.

9

10 The purpose of my testimony is to describe the projects that are required to provide
11 safe and reliable service to the Customer. I will also describe the cost estimate for
12 distribution and transmission upgrades to support the Customer's connection to the
13 electric grid.

14

15 **Q9. How is your testimony organized?**

16 A9. My testimony includes the following sections:

17 1. Project Descriptions

18 2. Estimated Company Project Costs

19

20 **Q10. Are you sponsoring any exhibits in this proceeding?**

21 A10. Yes. I am sponsoring the following exhibits:

22 Exhibit Description

23 A-1 Line Extension Agreement (LEA)

Line
No.

1 **Q11. Were these exhibits prepared by you or under your direction?**

2 A11. Yes, they were.

3

4 **Part I: Project Descriptions**

5 **Q12. Can you describe what projects are necessary to connect the Customer to the**
6 **electric grid?**

7 A12. There are three separate projects to achieve the Customer's connection in a safe and
8 reliable manner: 1) work to be completed by the Customer; 2) work to be completed
9 by DTE Electric and 3) work to be completed by the transmission provider. Projects
10 attributed to other entities are provided for contextual purposes only and do not
11 represent work that is within the Company's ownership, control, or cost
12 responsibility.

13

14 **Q13. What does the Customer's project include?**

15 A13. The Customer will be designing and constructing as well as owning two distribution
16 substations on their site.

17

18 **Q14. Can you describe the Company's project?**

19 A14. The distribution upgrades provided by the Company will connect the Customer's
20 substations to the transmission system through new overhead power lines. This
21 work includes installing the necessary equipment and metering to ensure the
22 equipment operates safely and reliably. The Company's project design is based on
23 the information that is currently available. I provide additional detail on the
24 Company's project in Part II.

Line
No.

1 **Q15. What does the Transmission Provider's project include?**

2 A15. The high-voltage transmission system is primarily owned and operated by ITC
3 Transmission (ITC). ITC is an independent transmission company that serves
4 southeastern Michigan, including the areas where DTE Electric provides electric
5 distribution service. ITC is a fully regulated company under the jurisdiction of the
6 Federal Energy Regulatory Commission.

7
8 ITC's project description is outlined in [MISO Expedited Review Request Cannoli](#)¹.
9 Associated costs for ITC's project are currently estimated at \$308 million² as shown
10 in Figure 1 below. Refer to Witness Burgdorf's testimony for a discussion on
11 transmission costs within the power supply cost categories.

12 **Figure 1 Detail of ITC Cost Estimate**

Description	Network Upgrade Description	Cost (\$)
Toll Road-Shoal_Sag Remediation	Remove sag on Toll Road-Shoal 120 kV line.	
Monroe-Wayne_Reconductor	Reconductor Monroe-Wayne 345 kV to high temperature conductor.	
Brownstown-Monroe2_Reconductor	Reconductor Brownstown-Monroe #2 345 kV to high temperature conductor.	
Total:		\$38,529,000
Description	Network Upgrade Description	Cost (\$)
Project Cannoli 345kV New Station	Build a new 345kV 5-row breaker-and-a-half configuration station. Install 15 breakers.	
Double circuit 345 kV UG line trenches	Install 2 double circuit 345 kV UG line trenches (total 2 miles)	
Install 3 Cap Banks at Cannoli	Install 3 116 MVAR capacitor banks at Cannoli station.	
Total:		\$229,000,000
Project Total (W/ 15% Adder):		\$308,000,000

¹ https://cdn.misoenergy.org/MISO_Expedited_Review_Request_Cannoli740599.docx

² Project costs provided by ITC

Line
No.

1 **Part II: Estimated Company Project Costs**

2 **Q16. How did the Company develop the cost estimates associated with the project?**

3 A16. The Company developed the cost estimates for the project using a structured
4 approach consistent with its established project management, engineering, and
5 estimating practices. The estimate reflects the defined project scope, applicable
6 design criteria, and execution requirements known at this stage of project
7 development. The cost estimate includes costs such as labor, materials, equipment,
8 and construction activities using current supplier pricing, historical purchase data,
9 recent contractor bid information, and established unit rates reflective of anticipated
10 site conditions.

11

12 **Q17. What is the estimated cost of the Company's project?**

13 A17. The project estimated cost ranges from \$29.1 million to \$44.3 million³, which is
14 necessary to account for cost variability associated with the different configuration
15 options still under consideration by the Customer.

16

17 **Q18. How will the costs of the new industrial substation needed to serve the**
18 **Customer be recovered?**

19 A18. The Line Extension Agreement (Exhibit A-1) commits the Customer to pay for up
20 to \$50 million of electric infrastructure upgrades to serve their facility. The LEA
21 also designates that the Customer is responsible for the costs of any unexpected site
22 conditions or events, including, but not limited to, environmental conditions, below
23 grade obstructions, or permitting/zoning issues. In the event the cost of the project
24 is greater than \$50 million and not related an unexpected site condition or event,

³ See WP SNB-1 for details

Line
No.

1 the Company will propose adding the net cost (i.e., actual costs less the \$50 million)
2 to its rate base for recovery in a future rate case consistent with Company's Rate
3 Book.

4

5 **Q19. How would the Customer have typically paid for the project?**

6 A19. Typically, the Customer would pay, through a Contribution in Aid of Construction
7 ("CIAC") payment, for the cost of the infrastructure needed for grid interconnection
8 less an allowance based on the Customer's load ("a CIAC allowance⁴"). If the
9 actual costs of the new overhead power lines exceeded the CIAC allowance, the
10 Customer would be responsible for paying for the difference through the CIAC
11 payment.

12

13 In this case, the Customer's CIAC allowance would be approximately \$550 million,
14 far exceeding the expected cost of the new overhead power lines. Under the
15 approved CIAC policy, the Customer would not be directly responsible for any costs
16 related to the new overhead power lines and instead the capital would be proposed
17 to be added to the Company's rate base with the associated costs allocated according
18 to approved methods.

19

20 The Company is not proposing to change the current CIAC policy.

21

22 **Q20. Does this conclude your direct testimony?**

23 A20. Yes, it does.

⁴ Standard Allowance per Rate Book section C6.2

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of)
DTE ELECTRIC COMPANY)
for Approval of Special Contracts)
and for other relief)

Case No. U-22058

REBUTTAL TESTIMONY

OF

STEVEN N. BENYARD

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF STEVEN N. BENYARD

Line
No.

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

3 A1. My name is Steven Benyard. My business address is: One Energy Plaza, Detroit,
 4 Michigan 48226. I am employed by DTE Energy Corporate Services LLC, a
 5 subsidiary of DTE Energy Company (DTE).

6

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

9 A2. Yes.

10

11 **Purpose of Testimony**

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

13 A3. The purpose of my testimony is to rebut certain positions and recommendations as
 14 proposed by certain witnesses that provided direct testimony in the instant case.
 15 These witnesses include:

- 16 • The Michigan Energy Innovation Business Council, Institute for Energy
- 17 Innovation, Ecology Center, Environmental Law & Policy Center, Union of
- 18 Concerned Scientists, and Vote Solar, (“MEICEO”) Witness Shaver;
- 19 Michigan Environmental Council, Natural Resources Defense Council, and
- 20 Sierra Club, collectively (“MNS”) Witness Woods

Line
No.

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

2 A4. Yes. I am sponsoring the following exhibit:

3 Exhibit Description

4 A-21 NDA U-22058 CEOMEIBCIEIDE-2.1c Supplemental-1Discovery
5 response Confidential

6

7 **Q5. Was this exhibit prepared by you or under your direction?**

8 A5. Yes, it was.

9

10 **System Studies and Operating Parameters**

11 **Q6. Can you provide a response to MEICEO Witness Shaver's recommendation**
12 **on page 31 of his testimony that DTE Electric provide timelines for**
13 **completion of a stability study, and short-circuit and EMT**
14 **(Electromagnetic Transient) studies?**

15 A6. DTE Electric does not directly conduct the stability study or the short-circuit study
16 recommended by Witness Shaver and therefore does not control the timeline for
17 when the studies will be completed. However, ITC, the transmission owner and the
18 party that will complete the stability study and short-circuit study, recently advised
19 the Company that the stability studies are ongoing, though a date for finalization
20 has not been determined, and screening-level short circuit analysis is complete.
21 DTE Electric will complete the EMT based transient simulations and estimates.
22 That study has commenced and completion is estimated in the fall of 2026.

Line
No.

1 **Q7. Why haven't the studies been completed yet?**

2 A7. The iterative nature of these dynamic studies requires a considerable amount of
3 time and careful review between the utility, transmission owner, MISO, and the
4 Customer.

5
6 **Q8. How is MISO involved in the study process?**

7 A8. DTE Electric and ITC are actively engaged in MISO's Large Load Working Group
8 (LLWG)¹ where regional requirements are being proposed by MISO to protect the
9 broader electrical system. Additionally, MISO participates in bi-weekly meetings
10 with DTE Electric and ITC to discuss operating parameters for large load customers
11 in the Company's service territory.

12
13 **Q9. Is MISO also involved in the Company's development of the operating
14 procedures for the Customer?**

15 A9. Yes, as mentioned above, these are discussed in bi-weekly meetings with MISO
16 and ITC.

17
18 **Q10. What is the status of the operating parameters for the Customer?**

19 A10. The operating parameters are site specific and are not expected to be final for
20 several more months. The Company provided a draft operating parameters
21 document in discovery, which is included with this testimony as CONFIDENTIAL
22 Exhibit A-21. The final values of the operating parameters are anticipated to require

¹ <https://www.misoenergy.org/engage/committees/large-load-working-group/>

Line
No.

1 several more months of studies², however, they must be finalized prior to
2 energization of the service per the PSA.

3

4 **Cost Estimation and CIAC Impact**

5 **Q11. With respect to the DTE Electric project scope to connect the Customer, do**
6 **you agree with MNS Witness Woods (page 14) that there is risk of cost**
7 **escalation beyond the \$50 million commitment from the Customer included in**
8 **the Line Extension Agreement?**

9 A11. While risk of cost escalation can exist on any project, cost escalation risk for this
10 specific project was accounted for within the estimate range of \$29.1-\$44.3 million
11 provided on page 6 of my direct testimony. Given the uncertainty in project start
12 timing and that this is a pre-design estimate, the range accounted for potential 4%
13 inflation, varying design complexity, and a 50% accuracy range.

14

15 Given the Company's estimated cost of associated distribution work has accounted
16 for a broad range of uncertainty, the expectation is that all distribution costs caused
17 by the Customer will be paid for by the Customer. In addition, the Customer has
18 agreed in the line extension agreement (LEA) to be responsible for the costs of any
19 unexpected site conditions or events. However, as discussed in my direct
20 testimony³, under the Company's current contribution in aid of construction
21 (CIAC) policy the Customer would receive a CIAC allowance of approximately
22 \$550 million - more than ten times the Company's cost estimate for the Customer's
23 distribution infrastructure. In this specific scenario, ordinarily the substation

² Studies include but are not limited to dynamic stability; harmonic analysis; transient switching; and voltage flicker.

³ See direct testimony of Company Witness Benyard, Pg 7, Ln 13

Line
No.

- 1 connection would be provided by the Company at no upfront cost to the Customer.
- 2 Despite this, the Customer has agreed to fund the first \$50 million of Customer-
- 3 caused distribution costs in addition to building and owning their own substation.
- 4
- 5 **Q12. Does this conclude your rebuttal testimony?**
- 6 A12. Yes, it does.

1 MR. JANISZEWSKI: Lastly, your Honor, I
2 want to move, pursuant to an agreement for the mutual
3 waiver of cross with the Attorney General, the Company
4 moves for the admission of Exhibit A-23 and Exhibit A-24,
5 which are hearing room exhibits that have been uploaded
6 onto the SharePoint.

7 JUDGE STALEY: All right. Any objection
8 to the admission of hearing room Exhibit A-23 and A-24?

9 Hearing none, hearing room Exhibits A-23
10 and A-24 are admitted into the record.

11 All right. Does that conclude the
12 Company's case, Mr. Janiszewski?

13 MR. JANISZEWSKI: It concludes the
14 Company's case, your Honor. I did want to correct a
15 representation I made earlier. There are two redactions
16 to Mr. Benyard's direct testimony, the testimony is not
17 filed as confidential.

18 JUDGE STALEY: O.K. But it does have
19 redactions to it?

20 MR. JANISZEWSKI: Two redactions on page
21 5, correct.

22 JUDGE STALEY: All right. Thank you.

23 MR. JANISZEWSKI: That concludes the
24 Company's case. Thank you.

25 JUDGE STALEY: Thank you,

1 Mr. Janiszewski.

2 All right. Mr. Wollenzien, for the
3 Attorney General, you may proceed with your case.

4 MR. WOLLENZIEN: Thank you, your Honor.
5 At this time, on behalf of the Attorney General, I'd like
6 to move to bind in the Direct Testimony and Exhibits of
7 Witness Sebastian Coppola. Mr. Coppola's Public direct
8 testimony consists of a cover page, the 1-page table of
9 contents, 26 pages of questions and answers, and a
10 27-page appendix. I'd also move for binding in of the
11 Confidential version of Mr. Coppola's direct testimony
12 which was provided to those individuals in this case
13 having executed NDCs for binding in in the Confidential
14 Record. I'd also move to bind in Mr. Coppola's prefiled
15 Confidential Exhibit AG-1 into the Confidential Record,
16 and also to move for binding in his other prefiled public
17 exhibits, AG-2 through AG-6.

18 JUDGE STALEY: O.K. Is there any
19 objection to the binding in of the prefiled Testimony of
20 Sebastian Coppola, which has both a Public and
21 Confidential version, or the admission of Appendix A, as
22 well as Confidential Exhibit AG-1, and Exhibits AG-2,
23 AG-3, AG-4, AG-5, and AG-6?

24 Hearing none, the prefiled Direct
25 Testimony of Sebastian Coppola, which has a Confidential
Penn Reporting, LLC - lori.penn@yahoo.com

1 as well as a Public version, are bound into the record,
2 and Appendix A, Confidential Exhibit AG, as well as
3 Exhibit AG-2 through AG-6 are admitted into evidence.

4 (Public Direct Testimony bound in.)

5 - - -

6 (Confidential Direct Testimony found on Page 896 of
7 the Confidential Record.)

8 - - -

June 5, 2026

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I. Introduction

2 **Q. PLEASE STATE YOUR NAME, OCCUPATION, AND ADDRESS.**

3 A. My name is Sebastian Coppola. I am an independent business consultant. My office is
4 at 5928 Southgate Rd., Rochester, Michigan 48306.

5 **Q. PLEASE SUMMARIZE YOUR PROFESSIONAL QUALIFICATIONS.**

6 A. I am a business consultant specializing in financial and strategic business issues in the
7 fields of energy and utility regulation. I have more than forty years of experience in public
8 utility and related energy work, both as a consultant and utility company executive. I have
9 testified in several regulatory proceedings before the Michigan Public Service
10 Commission (“MPSC” or “Commission”) and other regulatory jurisdictions. I have
11 prepared and/or filed testimony in rate case proceedings, revenue decoupling
12 reconciliations, gas conservation programs, Gas Cost Recovery (GCR) cases and Power
13 Supply Cost Recovery (PSCR) cases, and other proceedings. As accounting manager and
14 later financial executive for two regulated gas utilities with operations in Michigan and
15 Alaska, I have been intricately involved in regulatory proceedings related to gas cost
16 recovery cases, gas purchase strategies, rate case filings and power plant cost analysis.

17 **Q. WHAT EXPERIENCE DO YOU HAVE WITH ELECTRIC UTILITIES?**

18 A. I have performed rate case analyses and filed testimony in several electric general rate
19 cases addressing issues on revenue requirement, sales level determination, operations and
20 maintenance expenses, cost allocations, cost of capital, cost of service and rate design,
21 various cost tracking mechanisms and integrated resource plans. In addition, I have

1 performed analyses of power costs and filed testimony in power supply cost recovery
2 mechanisms, including reconciliation of annual power supply costs.

3 In my position as Senior Vice President of Finance at MCN Energy Group, I had
4 responsibility for project financing of independent power generation plants in which MCN
5 was an owner. In this regard, I was intricately involved and became knowledgeable of
6 PURPA qualified cogeneration plants in Michigan and other states. In addition, I was
7 involved in negotiating the development and financing of power generation and electricity
8 distribution plants in other countries, such as India.

9 **Q. PLEASE LIST SOME OF THE MORE RECENT CASES YOU HAVE**
10 **PARTICIPATED IN BEFORE THE MPSC AND OTHER REGULATORY**
11 **AGENCIES.**

12 A. Here is a partial list of the most recent regulatory cases in which I have participated in the
13 last two years:

- 14 ○ Filed testimony on behalf of the Michigan Attorney General in Consumers
15 Energy Company (CECo) 2025 gas rate case U-21981 on several issues,
16 including operation and maintenance expenses, capital expenditures, cost of
17 capital, and other items.
- 18 ○ Filed testimony on behalf of the Michigan Attorney General in DTE Gas
19 Company (DTE Gas) 2024-2025 GCR reconciliation in case No. U-21440.
- 20 ○ Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2025
21 gas rate case U-21973 on several issues, including revenues, operation and
22 maintenance expenses, capital expenditures, cost of capital, and other items.
- 23 ○ Filed testimony on behalf of the Michigan Attorney General in DTE Electric
24 (DTEE) 2024 PSCR reconciliation in Case No. U-21426.
- 25 ○ Filed testimony on behalf of the Michigan Attorney General in CECo proposed
26 sale of hydroelectric power generating assets in Case No. U-21985.
- 27 ○ Filed testimony on behalf of the Michigan Attorney General in SEMCO Energy
28 Gas Company (SEMCO) 2024-2025 GCR plan reconciliation in Case No. U-
29 21446.

- 1 ○ Filed testimony on behalf of the Michigan Attorney General in CEC0 2024 PS CR
- 2 reconciliation in Case N0. U-21424.
- 3 ○ Filed testimony on behalf of the Michigan Attorney General in CEC0 2025
- 4 electric rate case U-21870 on several issues, including operation and maintenance
- 5 expenses, capital expenditures, cost of capital, and other items.
- 6 ○ Filed testimony on behalf of the Michigan Attorney General in DTEE 2025
- 7 electric rate case U-21860 on several issues, including operation and maintenance
- 8 expenses, capital expenditures, cost of capital, and other items.
- 9 ○ Filed testimony on behalf of the Michigan Attorney General in DTE Gas
- 10 Company (DTE Gas) 2025-2026 GCR plan case No. U-21608.
- 11 ○ Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2023-
- 12 2024 GCR reconciliation in case No. U-21272.
- 13 ○ Filed testimony on behalf of the Michigan Attorney General in DTEE 2023 PS CR
- 14 Plan Case No. U-21594.
- 15 ○ Filed testimony on behalf of the Michigan Attorney General in CEC0 2024 gas
- 16 rate case U-21806 on several issues, including sales, operation and maintenance
- 17 expenses, capital expenditures, cost of capital, and other items.
- 18 ○ Filed testimony on behalf of the Michigan Attorney General in Michigan Gas
- 19 Utilities Corporation (MGUC) 2023-2024 GCR reconciliation in case No. U-
- 20 21274.
- 21 ○ Filed testimony on behalf of the Michigan Attorney General in DTEE 2023 PS CR
- 22 reconciliation in case No. U-21260.
- 23 ○ Filed testimony on behalf of the Michigan Attorney General in CEC0 2023-2024
- 24 GCR reconciliation in case No. U-21270.
- 25 ○ Filed testimony on behalf of the Michigan Attorney General in SEMCO 2023-
- 26 2024 GCR plan reconciliation in case No. U-21278.
- 27 ○ Filed testimony on behalf of the Michigan Attorney General in CEC0 2023 PS CR
- 28 reconciliation in case No. U-21258.
- 29 ○ Filed testimony on behalf of the Michigan Attorney General in CEC0 2024
- 30 electric rate case U-21585 on several issues, including operation and maintenance
- 31 expenses, capital expenditures, cost of capital, and other items.
- 32 ○ Filed testimony on behalf of the Michigan Attorney General in DTEE 2024
- 33 electric rate case U-21534 on several issues, including operation and maintenance
- 34 expenses, capital expenditures, cost of capital, and other items.
- 35 ○ Filed testimony on behalf of the Michigan Attorney General in the Upper
- 36 Peninsula Power Company (UPPCO) 2024 gas rate case U-21555 on several
- 37 issues, including operation and maintenance expenses, capital expenditures, cost
- 38 of capital, and other items.

- 1 ○ Filed testimony on behalf of the Michigan Attorney General in MGUC 2024 gas
2 rate case U-21540 on several issues, including operation and maintenance
3 expenses, capital expenditures, cost of capital, and other items.
- 4 ○ Filed testimony on behalf of the Michigan Attorney General in SEMCO 2023-
5 2024 GCR plan in case No. U-21277.
- 6 ○ Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2024
7 gas rate case U-21291 on several issues, including sales, operation and
8 maintenance expenses, capital expenditures, cost of capital, and other items.
- 9 ○ Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2022-
10 2023 GCR reconciliation in case No. U-21065.
- 11 ○ Filed testimony on behalf of the Michigan Attorney General in CEC0 2023 gas
12 rate case U-21490 on several issues, including sales, operation and maintenance
13 expenses, capital expenditures, cost of capital, and other items.
- 14 ○ Filed testimony on behalf of the Michigan Attorney General in DTM Michigan
15 Lateral Company (DMLC) 2023 Act 9 Transportation Service rate update in case
16 No. U-21525.
- 17 ○ Filed testimony on behalf of the Michigan Attorney General in DTEE 2022 PSCR
18 reconciliation in case No. U-21051.
- 19 ○ Filed testimony on behalf of the Michigan Attorney General in Michigan Gas
20 Utilities Corporation (MGUC) 2022-2023 GCR plan in case No. U-21067.
- 21 ○ Filed testimony on behalf of the Michigan Attorney General in CEC0 2023 PSCR
22 reconciliation in case No. U-21049.
- 23 ○ Filed testimony on behalf of the Michigan Attorney General in Indiana Power
24 Company 2023 electric rate case No. U-21461 on several issues, including sales,
25 operation and maintenance expenses, capital expenditures, cost of capital, and
26 other items.
- 27 ○ Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2023-
28 2024 GCR plan in case No. U-21271.

29 Appendix A elaborates further on my qualifications in the regulated energy field.

30 **Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

31 A. I have been asked by the Attorney General to perform an independent analysis of DTE
32 Electric Company's ("Company" or "DTEE") filing in Case No. U-22058 requesting
33 approval of special contracts with Google LLC, a subsidiary of Alphabet, Inc. to serve a

1 large scale data center with electric demand of 1,000 MW in Van Buren Township,
 2 Michigan. This testimony presents a report of that analysis with related recommendations.

3 **Q. WHAT TOPICS ARE YOU ADDRESSING IN YOUR TESTIMONY?**

4 A. I am addressing the following major topics in this case:

- 5 1. The Minimum Billing Demand threshold
- 6 2. The Termination Payment to be paid by Google
- 7 3. The parent company guaranty limitations
- 8 4. The uncertainty of the actual energy storage and renewable energy projects to be
- 9 selected and related costs
- 10 5. The large Demand Response Program reduction chosen by Google
- 11 6. The need to track transmission cost
- 12 7. The need for a tracking mechanism for net benefits accruing to other customers
- 13 from the Google and other data centers

14 The absence of discussion on other matters in my testimony should not be taken as an
 15 indication that I agree with those aspects of DTEE's filing. The narrow focus of my
 16 testimony is, instead, a consequence of focusing on certain issues within the available
 17 resources.

18 **Q. IS YOUR TESTIMONY ON THESE TOPICS ACCOMPANIED BY EXHIBITS?**

19 A. Yes. I am sponsoring the following exhibits, which were either prepared by me or under
 20 my direct supervision:

- 21 1. Exhibit AG-1 CONF Calculation of Residual Termination Payment
- 22 2. Exhibit AG-2 Programs.com Article on Data Center Boom
- 23 3. Exhibit AG-3 IEEFA Article on Risk of AI-driven Overbuilt Infrastructure
- 24 4. Exhibit AG-4 Google Substations, DTE Line Extension, and ITC Lines
- 25 5. Exhibit AG-5 DTEE Tracking of Data Center Related Transmission costs

1 6. Exhibit AG-6 DTEE Response on Tariff Rate change

2 **II. SUMMARY CONCLUSIONS & RECOMMENDATIONS**

3 **Q. PLEASE PROVIDE A SUMMARY OF YOUR CONCLUSIONS AND**
4 **RECOMMENDATIONS PERTAINING TO THE SPECIAL CONTRACTS AND**
5 **GOOGLE DATA CENTER.**

6 A. Based on my analysis of the Company's application, testimony, exhibits, and responses to
7 discovery, I have reached the following summary conclusions and recommendations:

- 8 1. The 80% Minimum Billing Demand threshold could negatively impact other
9 customers. In preparing various cost scenarios supporting its testimony, the
10 Company assumed an average load factor of 90% of contracted maximum
11 capacity. I recommend that the Commission reject the 80% Minimum Billing
12 Demand and order the Company to set the threshold at no lower than 90%.
- 13 2. The contract Termination Payment amount payable by Google is based on
14 the 80% Minimum Monthly Charge for the remaining years of the PSA with
15 no further obligation by Google after 17 years. The remaining 20% would be
16 absorbed by other customers if the Company is not able to find a replacement
17 customer to take the capacity. I recommend that the Commission order the
18 Company to modify the Primary Supply Agreement to include the
19 Termination Payment at 100% of total demand costs for the full 20-year term
20 of the agreement.
- 21 3. Google's payment obligations for the Termination Payment far exceed the
22 parent company guaranty. Other customers should not be at risk of absorbing
23 any shortfall in costs for which Google and its parent are responsible.
24 Therefore, I recommend that the Commission reject any limitations on the
25 parent guaranty and the bank letter of credit from the Primary Supply
26 Agreement and Clean Capacity Accelerator Agreement.

- 1 4. The 250 MW load reduction commitment under the DR program seems
2 extremely aggressive for a data center that must run 24 hours per day, 365
3 days of the year, nearly unimpeded. I recommend that any penalties assessed
4 to Google for non-performance under the DR program should be accounted
5 for separately, disclosed in DR proceedings and general rate cases, and
6 credited to other customers' rates.
- 7 5. I recommend that the Commission direct the Company to implement
8 appropriate cost accounting tracking procedures to allow complete and
9 accurate reporting of all transmission-related incremental costs for Google
10 and each new data center for presentation of the aggregate costs and benefits
11 that are impacting other customers.
- 12 6. I recommend that the Commission order the Company to establish a
13 regulatory liability account to capture the annual financial benefits from the
14 Google data center, and other data centers, for inclusion in future rate cases
15 as a reduction to future base rate increases or as a direct passthrough of the
16 financial benefits to customers through a separate credit refund. This
17 tracking mechanism will ensure that financial benefits are passed through to
18 customers and do not accrue to the benefit of the utility.
- 19 7. I recommend that, similar to the December 18, 2025 order in Case No. U-
20 21990, the Commission make clear to the Company that any and all
21 unrecovered costs from Google shall not be borne by other customers and
22 that DTE Electric bears responsibility for any remaining liability and that all
23 risk associated with the sufficiency of the collateral shall be borne by DTE
24 Electric.

25 The remainder of my testimony provides further details and support for these summary
26 conclusions and recommendations.

III. SUMMARY OF CONTRACT TERMS AND CONCERNS

A. PRIMARY SUPPLY AGREEMENT

Q. PLEASE PROVIDE A SUMMARY OF THE KEY TERMS OF THE PRIMARY SUPPLY AGREEMENT (PSA) FOR WHICH THE COMPANY REQUESTS APPROVAL.

A. According to the direct testimony of Company witness Neal Foley, beginning on page 3, the PSA allows Google LLC (Customer) to take service under the Company's Primary Supply Rate Schedule D11 with modified terms and conditions, including provisions in other contracts, such as the Clean Capacity Accelerator Agreement (CCAA), the Rider 12 Demand Response Agreement, and the Line Extension Agreement (LEA). The Company seeks approval of the contracts from the Commission by September 10, 2026.

The PSA has a term of 20 years with expected start of electric service in December 2027 and includes the following key terms and conditions:

1. *Rate Schedule Change* - The Customer can request a rate schedule change, but it cannot take effect prior to 24 months after completion of load ramp-up and 24 months prior to the requested rate schedule change taking effect. Any new rate schedule request cannot be cross subsidized by any other customer group. In response to discovery, the Company stated that, for the Customer to switch rates, the rate must be approved by the Commission after the PSA Contract Date. As such, the Commission maintains appropriate oversight of the availability of future rate schedules the Customer could switch to.¹

2. *Minimum Billing Demand* - Under the PSA, the Customer has agreed to a Minimum Billing Demand (MBD) payment of 80% of the contract capacity of 1,000 MW, or

¹ Exhibit AG-6 includes Discovery Responses (DR) AGDE-1.5a-b.

800 MW once the load ramp-up is achieved. This means that the Customer will be responsible for a Minimum Monthly Charge (MMC) of 80% of contract demand if actual energy use falls below the 80% threshold. Under Rate Schedule D11, the MBD and MMC will be applied to the Power Supply Capacity Demand Charge, the Power Supply Non-Capacity Demand Charge, and the Distribution Demand Charge. Based on the D11 rates approved in Case No. U-21860, the MMC will be \$13.8 million monthly or \$165.1 million annually.

3. *Load Ramp-up Flexibility* - The PSA anticipates a load ramp-up for the data center to be reached by December 2028. However, there is flexibility for the Customer to delay the ramp-up by up to 18 months with no change in contract capacity allowed.
4. *Contract Capacity Reduction* - The contract capacity can be reduced under certain circumstances if the Company is not able to meet the Customer's load ramp-up or the maximum load requirements. The Company and the Customer will negotiate and agree on a solution or accept the Company's proposed capacity adjustment. The Customer can accept the Company's proposed capacity adjustment or terminate the agreement and pay the applicable termination payments.
5. *Termination Payment* – If a termination payment is triggered under Section 7.0 of the PSA, the Company will recover between 15 and 17 years of Minimum Monthly Charges (MMC) depending on the date of termination. As stated above, the MMC is based on the 80% MBD. Based on the provisions in the PSA and the D11 rates approved in Case No. U-21860, the Termination Payment at the completion of the load ramp-up would be \$2.48 billion.²
6. *Energy Waste Reduction (EWR)* – The Customer has committed to a self-directed EWR program with an annual target reduction of 1.5% of peak load.
7. *Affordability Backstop* – According to the Company the PSA ensures that the aggregate benefits, including revenues received from the Customer and avoided costs, outweigh the costs of serving the Customer's load. PSA Exhibit A-16 states

² Neal Foley direct testimony at page 18.

1 obligated to provide up to 1,000 MW of power at any point in time and must have full
2 generating and energy storage resources in place to serve that full load. If the Customer is
3 not taking the full load, then the Company must sell the 200 MW of excess capacity at a
4 value potentially lower than the cost of acquiring the capacity. The cost differential could
5 negatively impact other customers. In preparing various cost scenarios supporting its
6 testimony, the Company assumed an average load factor of 90% of contracted maximum
7 capacity. This is a more reasonable level that reduces any potential negative impact on
8 other customers.

9 Therefore, I recommend that the Commission reject the 80% Minimum Billing Demand
10 and order the Company set a threshold no lower than 90%.

11 **Q. PLEASE DISCUSS YOUR CONCERNS WITH THE TERMINATION PAYMENT**
12 **AMOUNT AND THE END DATE FOR ANY PAYMENT DUE.**

13 A. The Termination Payment amount is based on the 80% Minimum Monthly Charge for the
14 remaining years of the PSA with no further obligation by the Customer after 17 years.
15 There are two problems here. First, under the Minimum Monthly Charge calculation the
16 Company does not get to recover 100% of the demand costs billable to the Customer, but
17 only 80% of the total costs. The remaining 20% would be absorbed by other customers if
18 the Company is not able to find a replacement customer to take the capacity. Based on the
19 sample calculations provided in Exhibit E to the PSA, the remaining charges for the 20%
20 not included in the Termination Payment could be as much as [Begin Conf] [REDACTED]
21 [End Conf] at the beginning of the contract in December 2027 and declining in future
22 months as a portion of the costs are billed. Exhibit AG-1 Confidential includes the

1 calculation of the remaining 20% of the total termination costs based on the Company's
2 model.

3 Second, Section 7.3 of the PSA sets certain limitations that basically end any termination
4 payments after the 17th anniversary of the Commencement Date of the agreement, which
5 is the date that the data center begins to take electric service. There is no sound reason why
6 the Termination Payment should stop three years short of the end of the 20-year contract
7 term.

8 Therefore, I recommend that the Commission order the Company to modify the PSA to
9 include the Termination Payment at 100% of total demand costs for the full 20-year term
10 of the agreement.

11 **Q. PLEASE DISCUSS YOUR CONCERNS WITH THE LIMITATION ON THE**
12 **PARENT GUARANTY.**

13 A. Section 8 of the PSA addresses the general requirements for Customer Collateral and parent
14 company guaranty. Exhibit C Confidential specifies a parent company [Begin Conf]

15 [REDACTED]

16 [REDACTED]

17 [REDACTED]

18 [REDACTED]

19 [REDACTED]⁴ [End Conf]

³ Exhibit E to the PSA in Exhibit A-16 Confidential for December 2027.

⁴ Exhibit E amount plus Exhibit AG-1 for December 2027.

1 Should the data center fail to start operations or significantly underperform, triggering a
2 Termination Payment, the parent company guaranty needs to be at the level that ensures
3 full payment of the Customer's total obligations. The Company and other customers
4 should not be at risk to absorb any shortfall in costs for which the Customer and its parent
5 are responsible. Therefore, I recommend that the Commission reject the [Begin Conf]

6 [REDACTED]
7 [REDACTED] [End Conf].

8 **Q. IN HIS TESTIMONY AND RESPONSE TO DISCOVERY, MR. FOLEY STATES**
9 **THAT SOME OF THE PSA TERMS AND PROVISIONS IN THIS CASE ARE**
10 **SIMILAR OR SUPERIOR TO THOSE APPROVED BY THE COMMISSION IN**
11 **CASE NOS. U-21859 AND U-21990. HOW DO YOU RESPOND?**

12 A. The similar or superior terms and conditions to which Mr. Foley refers primarily pertain to
13 the 80% MBD, the termination payment period, and the parent company guaranty. The
14 Google case is the first time that an actual data center project has been presented to the
15 Commission and intervening parties where specific terms have been disclosed and the
16 extent of cost impacts on other customers has been quantified and visible. Case No. U-
17 21859 involved the setting of a Large Load Tariff without the details of a specific of a large
18 data center presented that would have allowed the Commission and other parties to that
19 case to more fully assess what the potential dollar impact of an 80% MBD would be for
20 non-data center customers, in contrast to a higher MBD. Similarly, there was no context
21 regarding the impact of partial termination payments for limited periods of time and limited
22 parent guarantees that do not cover full cost obligations of the data center customers.

1 Case No. U-21990, pertaining to the Oracle data center, was a secretive process with
2 basically no public disclosure of key terms or financial impacts on other customers. The
3 Google data center case has brought to light the large potential financial implications of
4 limiting MBD, termination payments, and collateral guarantees to less than 100% of the
5 financial obligations of the data center customer. The risk exposure for other customers
6 and the utility is often hundreds of millions of dollars.

7 Therefore, I recommend that the Commission use this case and my recommendations to
8 re-evaluate the prior financial limitations set in Case Nos. U-21859 and U-21990 and
9 provide broader protections to non-data center customers of the utility and even the utility
10 itself, in the event it must backstop residual payments not made by the data center customer.

11 **B. CLEAN CAPACITY ACCELERATOR AGREEMENT**

12 **Q. PLEASE PROVIDE A SUMMARY OF THE KEY TERMS OF THE CLEAN**
13 **CAPACITY ACCELERATOR AGREEMENT (CCAA) FOR WHICH THE**
14 **COMPANY REQUESTS APPROVAL.**

15 **A.** According to the direct testimony of Mr. Foley beginning on page 23, the CCAA initial
16 contract term is also 20 years and mirrors the PSA. The contract provides for the
17 deployment of up to 480 MW of energy storage projects and up to 1,600 MW of renewable
18 energy projects. In his testimony, Mr. Foley states that the Company has designed the
19 CCAA with provisions for the Customer to pay the full cost or revenue requirements
20 associated with each project. Additionally, the Customer will procure 300 Zonal Resource

1 Credits (ZRCs) for a five-year period from June 1, 2028 to May 31, 2033 and transfer those
2 ZRCs to the Company to assist in meeting the Customer's capacity needs.

3 The key terms and conditions of the CCAA are:

- 4 1. *Energy Storage Portfolio* – The CCAA includes up to 480 MW of energy storage
5 projects with 55 MW of 8-hour duration and 425 MW of 4-hour duration. The
6 Company states that this storage capacity will be sourced through requests for
7 proposal and may entail a combination of projects, including self-build, build-
8 transfer agreements, and third-party tolling agreements.
- 9 2. *Renewable Energy Portfolio* – Under the CCAA, the Company contemplates
10 developing 1,600 MW of renewable energy projects in compliance with the
11 Company's Renewable Portfolio Standard (RPS). At the request of the Customer,
12 40% of the renewable capacity will be under the Voluntary Green Pricing (VGP)
13 program. No projects have been identified to date, and the Company plans to
14 include those projects in the Integrated Resources Plan (IRP) to be filed later in
15 2026.
- 16 3. *Project Pricing* – For both the energy storage and renewable energy projects, the
17 Customer will pay the full cost of each project for the respective depreciable life.
18 For projects with depreciable life past the term of the CCAA, the Company will
19 calculate the residual amount and accelerate cost recovery within the 20-year term
20 of the CCAA. The annual costs to be billed to the Customer will be based on the
21 traditional revenue requirement model, including depreciation expense, AFUDC,
22 return on investment, investment tax credits, O&M expenses, property taxes, and
23 insurance. The Company will perform an annual reconciliation of costs billed in
24 the prior year to actual costs incurred to ensure that any estimated costs are
25 reconciled to actual costs and the Customer pays the total actual costs incurred by
26 the Company. The Company intends to provide information on the annual cost
27 reconciliation to parties in future general rate cases and other pertinent proceedings,
28 such as the REP reconciliation cases.

- 1 4. *ZRC Transfer* – The Customer has agreed to purchase 300 MW of ZRCs for the
 2 five years from June 1, 2028 to May 31, 2033, which it will transfer to the
 3 Company, to assist with meeting the generating capacity accreditation requirements
 4 with MISO. The Customer has agreed to pay a Financial Compensation
 5 Mechanism amount to the Company based on the MISO Cost of New Entry applied
 6 to the 300 ZRCs. This is an arrangement between the Company and the Customer
 7 and other customers will not be responsible for this cost.
- 8 5. *Capacity Credits* – Pages 32 through 39 of Mr. Foley’s direct testimony describe
 9 various capacity credits that the Customer will receive from MISO based on the
 10 accredited capacity from the energy storage projects, renewable energy projects,
 11 and the ZRCs.
- 12 6. *Contract Termination and Termination Payment* – The Customer cannot
 13 voluntarily terminate the CCAA. If the contract is terminated through Customer
 14 default, the Customer will be obligated to make a termination payment. The
 15 termination payment will be equal to the unrecovered portion of the revenue
 16 requirement for the remaining life of each project included under the CCAA.
 17 Exhibit E beginning on page 47 of the CCAA in Exhibit A-18 Confidential shows
 18 the declining potential termination payment starting at [Begin Conf] [REDACTED]
 19 [REDACTED] [End Conf].
- 20 7. *Credit and Collateral Requirements* – Similar to the PSA, the CCAA includes a
 21 parent guaranty from [Begin Conf] [REDACTED]
 22 [REDACTED]
 23 [REDACTED]
 24 [REDACTED]
 25 [REDACTED]
 26 [REDACTED] [End Conf] Schedule 1 on page 26 of Exhibit A-18
 27 Confidential shows the annual guaranty amount.

⁵ Exhibit C to CCAA on page 41 of Exhibit A-18 Confidential.

1 **Q. WHAT CONCERNS DO YOU HAVE WITH THE CCAA?**

2 A. I have concerns in two major areas: the uncertainty of energy storage and renewable energy
3 projects to be developed and the related cost, and the parent company guaranty cap.

4 **Q. PLEASE DISCUSS YOUR CONCERNS WITH THE PLANNED ENERGY**
5 **STORAGE AND RENEWABLE ENERGY PROJECTS.**

6 A. The Company has not identified and selected the energy storage and renewable projects
7 that will be included in the portfolio of resources to supplement its current resources and
8 provide the necessary total capacity to serve the Customer. To provide an indication of
9 potential costs for those resources, it used historical costs from energy storage and
10 renewable energy projects previously installed as a proxy for actual costs. The Company
11 plans to solicit bids for energy storage projects in July 2026 and incorporate the renewable
12 energy projects with the upcoming filing of the IRP later in 2026.

13 The lack of actual information makes it difficult to truly assess the reasonableness of the
14 historical proxy costs, the indicative termination payments, or the parent guaranty cap.
15 Therefore, in this regard, I recommend that the Commission take a cautious approach to
16 ensure protection of other customers from shortfalls in Termination Payment cost recovery
17 from the Customer and under the parent guaranty.

18 **Q. PLEASE DISCUSS YOUR CONCERNS WITH THE LIMITATION ON THE**
19 **PARENT GUARANTY.**

1 A. Section 11 of the CCAA addresses the general requirements for Customer Collateral and
 2 the parent company guaranty. Exhibit C Confidential specifies a parent company [Begin
 3 Conf] [REDACTED]
 4 [REDACTED]
 5 [REDACTED]
 6 [REDACTED]
 7 [REDACTED]
 8 [End Conf]

9 As stated earlier, should the data center fail to start operations or significantly
 10 underperform, triggering a Termination Payment, the parent company guaranty needs to
 11 be at the level that ensures full payment of the Customer's total obligations. This is even
 12 more important under the CCAA given the fact that the actual full cost of the energy storage
 13 and renewable generation resources is unknown. The Company and other customers
 14 should not be at risk of absorbing any shortfall in costs for which the Customer and its
 15 parent are responsible. Therefore, I recommend that the Commission reject the parent
 16 guaranty cap [Begin Conf] [REDACTED]
 17 [REDACTED] [End Conf]

18 **Q. IS THERE A GENERAL CONCERN WITH OVERCAPACITY OF DATA**
 19 **CENTERS BEING BUILT AROUND THE COUNTRY?**

⁶ Schedule 1 on page 26 of the CCAA in Exhibit A-18 Confidential.

1 A. Yes. A recent article by Programs.com, an IT security publication, reported that demand
2 for data centers is projected to nearly triple by 2030, driven primarily by expected increases
3 in Artificial Intelligence (AI), demand for data processing, and storage. New data centers
4 are proliferating in nearby states, such as Indiana and Ohio, as well as in other states. The
5 U.S. had a total of 4,280 data centers as of May 2026, with several more hyperscale centers
6 in various stages of development.⁷ Most of the hyperscale projects, similar to the Google
7 and Oracle projects, rely on anticipated demand for computing power from AI.

8 Should that demand fizzle, the resulting overcapacity could result in project cancellations,
9 failures, or data centers underutilization. The result could be that data centers, such as
10 those backed by Google and Oracle, will not require the anticipated level of electric
11 capacity and energy consumption, triggering defaults and termination payments. The same
12 sentiment is echoed by utility and other industry executives in a 2025 article published by
13 the Institute for Energy Economics and Financial Analysis (IEEFA).⁸

14 Therefore, to protect other customers it is critical to ensure that payments for electric
15 service, generation and storage resources, termination payments, and collateral guarantees
16 cover 100% of the costs attributable to the data center customer.

⁷ Exhibit AG-2.

⁸ Exhibit AG-3.

C. OTHER CONTRACTS AND SERVICES

Q. PLEASE DISCUSS THE OTHER CONTRACTS THAT SUPPORT THE PSA AND CCAA.

A. Company witness Shawn Burgdorf discusses the Rider 12 Demand Response (DR) Agreement beginning on page 22 of his direct testimony. According to Mr. Burgdorf, the Customer has requested to participate in the Demand Response program for up to 250 MW, or 25% of its peak load of 1,000 MW. The DR contract begins on June 1, 2027 and ends May 31, 2033 with a required firm service level of 650 MW, which allows for an interruption or reduction in energy delivery for up to 250 MW during a MISO-called demand response or emergency event.

In his direct testimony, Mr. Burgdorf states that MISO can assess penalties to the Customer for non-performance in reducing power usage to the level called upon, including losing accreditation of resources and other damages for lost auction price revenues in future MISO plan years.

Regarding the Line Extension Agreement (LEA), Company witness Steven Beynard discusses this agreement beginning on page 6 of his direct testimony. According to his testimony and the LEA, the Company will provide the required interconnections between the ITC transmission lines switchyard and the two substations to be built and owned by the Customer. The Company will also review and approve selected equipment at the Customer's substations, which will be operated by the Customer. Additionally, DTEE will install metering equipment and deploy load shedding controls at the Customer's substations.

1 Exhibit AG-4 includes DR AGDE-2.45a-b and 2.47a-b with a site schematic describing the
2 distribution, transmission, and substation interconnections.

3 In his direct testimony, Mr. Beynard states that the costs to be incurred under the LEA are
4 projected at between \$29.1 million and \$44.3 million. The Customer has agreed to cover
5 up to \$50 million for the DTEE line extension work. In the eventuality that actual costs
6 exceed \$50 million, those additional costs would be added to the Company's rate base.

7 On page 5 of his testimony, Mr. Beynard also discusses the work to be performed by the
8 transmission service provider, ITC, at the Google data center site at an estimated cost of
9 \$308 million to install two 345 kV transmission lines, a switchyard substation, and related
10 equipment. This cost will be added to ITC's rate base and included in ITC Schedule 9
11 charges billed to all its customers, including DTEE.⁹ The Schedule 9 charges flow through
12 the PSCR.

13 **Q. WHAT CONCERNS DO YOU HAVE WITH THE RIDER 12 DR AGREEMENT?**

14 A. The 250 MW load reduction commitment under the DR program seems extremely
15 aggressive for a data center that must run 24 hours per day for 365 days of the year, nearly
16 unimpeded. Other customers will pay the costs for the Customer participating in the DR
17 program. To the extent that the Customer is not able to meet its commitment to shed load
18 when called upon by MISO under the DR program, it is necessary for the Company to

⁹ Exhibit AG-4 includes DR AGDE-2.46a.

1 ensure that other customers are made whole for any payments made to the Customer for
2 participation in the DR program.

3 Therefore, I recommend that any penalties assessed to the Customer for non-performance
4 under the DR program should be accounted for separately, disclosed in DR proceedings and
5 general rate cases, and credited to other customers' rates.

6 **Q. WHAT CONCERNS DO YOU HAVE WITH THE ITC TRANSMISSION COSTS?**

7 A. There are two distinct ITC transmission cost areas. First, there is the installation of
8 transmission lines and the switchyard substation at the Google data center site. As discussed
9 above, the cost for those installations will be included in ITC's rate base and billed to its
10 customers, including DTEE. In response to discovery, the Company stated that it plans to
11 track the capital-related costs for the Google ITC installation and will be able to identify
12 how much it contributes to the overall Schedule 9 costs billed by ITC to DTEE after the
13 start of service to the Customer.¹⁰

14 Second, ITC will likely be involved in connecting the energy storage locations and new
15 renewable energy projects to transmit power generation from those projects to DTEE. For
16 the energy storage resources, ITC will most likely also be involved in delivering power to
17 recharge the batteries after they are discharged. The Company did not address those
18 transmission interconnection installations in filed direct testimony in this case, probably due

¹⁰ Exhibit AG-5 includes DR MNSDE-2.21aiv.

1 to the fact that it is still uncertain where those storage and renewable resources will be
2 located.

3 However, the transmission capital costs related to those incremental resources need to be
4 tracked and reported separately, along with the ITC O&M costs related to all of the new
5 transmission facilities installed to supply power to the Google data center from resource
6 origin to the data center delivery point. Additionally, there may be incremental MISO
7 transmission-related oversight and system management costs pertaining to the new data
8 centers, which are billed through other transmission schedules. These additional
9 incremental costs and ITC costs related to the Google, Oracle, and other data centers that
10 may occur in future years need to be separately identified to ensure that other customers are
11 not subsidizing data center customers.

12 Therefore, I recommend that the Commission direct the Company to implement appropriate
13 cost accounting tracking procedures to allow complete and accurate reporting of all
14 transmission-related incremental costs for each new data center for presentation of the
15 aggregate costs and benefits that are impacting other customers.

16 **IV. DATA CENTER COSTS AND BENEFITS**

17 **Q. PLEASE SUMMARIZE THE COMPANY'S PLANS TO REPORT THE**
18 **INCREMENTAL COSTS OF THE GOOGLE DATA CENTER, PRESENT**
19 **ACTUAL COST RECONCILIATIONS, AND IDENTIFY BENEFITS ACCRUING**
20 **TO OTHER CUSTOMERS.**

1 A. As discussed above under the CCAA, the Company plans to present the additional costs
2 incurred for renewable energy projects in its annual REP reconciliations. The Company
3 also plans to present in future rate cases the annual reconciliation of costs incurred from
4 CCAA resources against the amounts billed to the Customer to demonstrate that the
5 Customer is paying the total cost of those resources. Additionally, as I recommended
6 earlier, the Company needs to show in the PSCR reconciliation cases the actual incremental
7 transmission costs caused by each of the Google and Oracle data centers, and any other data
8 centers that may come along.

9 Furthermore, as discussed by Mr. Foley and detailed in the direct testimony of witness
10 Aaron Willis, the Company plans to calculate and present a periodic aggregate
11 reconciliation of net benefits accruing to other customers from the Google data center. In
12 Exhibit A-19, the Company presented an illustration of potential net benefits by year from
13 2028 to 2047 that total to \$1.7 billion. The costs and financial benefits shown in Exhibit A-
14 19 are based on certain assumptions about future cost increases and resource additions that
15 will likely vary from actual costs in future years. However, the concept has merit, and this
16 reconciliation should be completed annually based on actual costs, including costs and
17 revenues under the CCAA.

18 **Q. SHOULD THE COMMISSION ORDER THE COMPANY TO GO FURTHER**
19 **THAN SIMPLY PRESENTING THE RECONCILIATION OF NET BENEFITS?**

20 A. Yes. The Commission should order that the Company establish a regulatory liability
21 account to capture the annual financial benefits from the Google data center, and any other

1 data centers, for inclusion in future rate cases as a reduction to future base rate increases or
2 as a direct passthrough of the financial benefits to customers through a separate credit
3 refund. This tracking mechanism will ensure that financial benefits are actually passed
4 through to customers and do not accrue to the benefit of the utility.

5 In recent news releases, the Company has stated that due to additional data center revenues
6 it may defer filing a new rate case for a couple of years. That announcement assumes that
7 the Company will retain any financial benefits from additional revenues billed to the data
8 center customers. Such an approach obscures the claim that new large data centers will
9 provide incremental benefits to customers and reduce rates. The better approach is to
10 capture the financial benefits in a regulatory liability account and for the utility to take those
11 benefits into consideration when deciding whether or not to file a rate case. Such a
12 mechanism will provide a more sound and transparent approach to show that other
13 customers are actually benefiting and are not being financially disadvantaged by the new
14 large data centers served by the Company.

15 **Q. IF THE DATA CENTER AGGREGATE COSTS EXCEED THE BENEFITS,**
16 **SHOULD OTHER CUSTOMERS BE RESPONSIBLE FOR THE INCREMENTAL**
17 **COSTS?**

18 A. No. If at any time during the term of the PSA, CCAA, and other agreements with the
19 Customer or after the expiration of those agreements, costs related to the Customer exceed
20 any benefits, or there are no longer any offsetting benefits, the Company and not the other
21 customers should be responsible for such costs. This requirement is similar to the

1 Commission pronouncements for the Oracle data center in Case U-21990, where the

2 Commission stated:

3 Moreover, the approval in the instant case is conditioned upon the assumption, as
4 represented by DTE Electric in its application, testimony, and subsequent filings,
5 and in the materials provided pursuant to the Staff's audit, that the Customer's
6 obligations under Rate D11 and the special contracts will at least cover the costs to
7 serve the Customer (including generation, transmission, distribution, or other
8 costs)... In addition, in the event of a failure to pay the MBD under the PSA, or in
9 the event of a termination, default, or other event whereby DTE Electric is required
10 to draw on the letter of credit or parental guaranty, if the company determines that
11 the specified collateral is not sufficient to cover the full amount of the remaining
12 financial exposure associated with the ESA or the PSA (minus the value to
13 customers), the Commission specifically cautions DTE Electric that any
14 unrecovered costs shall not be borne by ratepayers and that DTE Electric bears
15 responsibility for any remaining liability. All risk associated with the sufficiency of
16 the collateral shall be borne by DTE Electric.¹¹

17 **Q. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?**

18 A. Yes, it does. However, I reserve the right to amend, revise and supplement my testimony
19 to incorporate new information that may become available.

¹¹ Case U-21990, December 18, 2025, Order at 40 – 41.

Experience and Qualifications of Sebastian Coppola

Mr. Sebastian Coppola is an independent energy business consultant and president of Corporate Analytics, Inc., whose place of business is located at 5928 Southgate Rd., Rochester, Michigan 48306.

EMPLOYMENT BACKGROUND

Mr. Coppola has been an independent consultant for 22 years. Before that, he spent three years as Senior Vice President and Chief Financial Officer of SEMCO Energy, Inc. with responsibility for all financial operations, corporate development and strategic planning for the company's Michigan and Alaska regulated and non-regulated operations. During the period at SEMCO Energy, he had also responsibility for certain storage and pipeline operations as President and COO of SEMCO Energy Ventures, Inc. Prior to SEMCO, Mr. Coppola was Senior Vice President of Finance for MCN Energy Group, Inc., the parent company of Michigan Consolidated Gas Company (now DTE Gas Company).

ENERGY INDUSTRY EXPERTISE

During his 27-year career at SEMCO Energy, MCN Energy, and MichCon, Mr. Coppola held various analytical, accounting, managerial and executive positions, including Manager of Gas Accounting with responsibility for maintaining the accounting records and preparing financial reports for gas purchases and gas production. In this role, he had also responsibility for preparing Gas Cost Recovery (GCR) reconciliation analysis and reports and supporting preparation of testimony for the cost of gas reconciliation proceedings before the MPSC. Over the years, Mr. Coppola also held the positions of Treasurer, Director of Investor Relations, Director of Accounting Services, Manager of Corporate Finance, Manager of Customer Billing, and Manager of Materials Inventory and Warehousing Accounting. In many

Experience and Qualifications of Sebastian Coppola

of these positions he interacted with various operating areas of the company and was intricately involved in construction and operating programs, defining gas purchasing strategies, rate case analysis, cost of capital studies and other regulatory proceedings.

Mr. Coppola is intricately knowledgeable of capital markets and financial institutions. As Treasurer and Vice President of Finance, he directed the issuance of more than \$2 billion in securities, including common stock, corporate bonds, tax-deductible preferred stock and high-equity value convertible securities. He established bank lines of credit, commercial paper and asset acquisition facilities. He has had extensive interactions with equity and debt investors, financial analysts, rating agencies and other members of the financial community.

ENERGY INDUSTRY AND REGULATORY EXPERIENCE

As a business consultant, Mr. Coppola specializes in financial and strategic business issues in the fields of energy and utility regulation. He has more than forty years of experience in public utility and related energy work, both as a consultant and utility company executive. He has testified in several regulatory proceedings before State Public Service Commissions. He has prepared and/or filed testimony in electric and gas general rate case proceedings, power supply and gas cost recovery mechanisms, revenue and cost tracking mechanisms/riders, multi-year rate plans and incentive ratemaking, and other regulatory matters.

Mr. Coppola has extensive experience with gas and electric utilities in the areas of operations, supply and regulatory proceedings. He has led or participated in the financial operations, gas supply planning and/or gas cost recovery arrangements of two major gas utilities in Michigan and in Alaska. He has prepared

Experience and Qualifications of Sebastian Coppola

testimony in multiple electric and gas general rate cases, Power Supply Cost Recovery (PSCR) and Gas Cost Recovery reconciliation proceedings, Cast Iron and Pipeline Replacement Programs and other regulatory cases on behalf of the Michigan Attorney General, Citizens Against Rate Excess (CARE), the Public Counsel Division of the Washington Attorney General, the Illinois Attorney General, the Maryland Office of Public Counsel, and the Ohio Office of Consumers Counsel in electric and gas utility rate cases, including AEP Ohio, Ameren-Illinois Utilities, Avista, Consumers Energy, DTE Electric Company, MichCon (DTE Gas Company), Michigan Gas Utilities Corp, Nicor Gas, PacifiCorp, Peoples Gas, Puget Sound Energy, SEMCO, Upper Peninsula Power Company, Washington Gas, and Wisconsin Public Service Company.

Mr. Coppola has also provided assistance and proposals to the Maryland Office of Peoples Counsel on Multi-Year Rate Plans and Performance-Based Ratemaking. Additionally, he prepared a report on the financial condition and risks of AltaGas and Washington Gas Light Company which was filed with the Maryland Public Service Commission in July 2019 in Case No. 9449.

As accounting manager and later financial executive for two regulated gas utilities, he has been intricately involved in construction materials procurement, gas purchase strategies and CGR reconciliation cases. He has had direct responsibility for preparing GCR reconciliation analysis and reports and supporting preparation of testimony for the cost of gas reconciliation proceedings before the Michigan Public Service Commission (MPSC). He is intricately familiar with construction projects, the power supply and gas cost recovery mechanisms, gas supply and pricing issues, and regulatory issues faced by utilities.

Experience and Qualifications of Sebastian Coppola

During his long career at DTE Gas, among other responsibilities, Mr. Coppola was responsible for overseeing the operation of the MichCon Wet Header System, a pipeline that transported natural gas and gas liquids from Michigan gas producing fields in the Niagara Reef in the northern area of the lower peninsula of Michigan to processing plants in Kalkaska, MI. His responsibility included ensuring the day-to-day flow of gas and liquids, and identifying operating issues requiring corrective action.

He was also responsible for the study to assess the feasibility of building the Saginaw Bay Pipeline, a transmission line to move Praire Du Chein natural gas reserves in the eastern area of Michigan to processing plants. Prior to the construction of the pipeline, Mr. Coppola worked with operating management to prepare requests for proposal for the construction project and the selection of qualified bids. During and subsequent to the construction of the pipeline, Mr. Coppola assisted in the management and oversight of the pipeline, including review of operating performance and profitability.

Additionally, as Manager of Materials Inventory, Warehousing and Procurement at DTE Gas, Mr. Coppola worked closely with suppliers of pipe, control valves, flanges, meters, fittings, equipment and thousands of other parts and materials used in the construction, repair and maintenance of DTE Gas's transmission, distribution and storage facilities, including repairs and upgrades to compressor stations, and replacement of cast iron mains, bare and wrapped steel pipelines and service lines. His responsibilities included the review of design and construction blueprints and plans with frequent visits to construction sites during excavation of new pipeline trenches, and during replacement of defective or leaky

Experience and Qualifications of Sebastian Coppola

pipes, and replacement of control valves. Mr. Coppola also made frequent visits and inspection to storage facilities owned by DTE Gas to understand materials requirements during planned construction projects. Mr. Coppola was also responsible for ensuring that materials and equipment were ordered to meet material standards and safety codes.

Through these responsibilities, Mr. Coppola gained knowledge and expertise with field construction project procedures, pipeline trenching problems, installation inspections, operation and maintenance cycles, and the material procurement of pipe, valves, flanges, meters and thousands of other parts and equipment used in the construction of natural gas transmission, distribution and storage facilities.

During his career with MCN Energy Group, Mr. Coppola was responsible for the evaluation of investments in interstate pipelines, new gas storage facilities, gas cogeneration plants, and construction of new power plants in the U.S. and India. Mr. Coppola was a key member of the negotiating team with contractors and suppliers tasked to build the power facilities, including the evaluation of Engineering, Procurement and Construction (EPC) bids and contracts.

After his move to SEMCO Energy Corporation in 1999, Mr. Coppola was responsible for the acquisition and integration of pipeline construction companies providing services to gas utilities and interstate pipelines. In addition to its gas utility business in Michigan and Alaska, serving approximately 350,000 customers, SEMCO Energy owned SEMCO Pipeline Construction, a non-regulated business providing gas pipeline and natural gas facilities construction services to gas utilities and interstate pipelines in the Midwest and Eastern regions of the U.S. SEMCO

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Pipeline Construction provided construction services similar to KS Energy, Northern Pipeline and other contractors used by the Company. During his tenure at SEMCO Energy, Mr. Coppola reviewed dozens of pipeline construction companies and acquired six companies. Mr. Coppola's responsibilities included management of the performance and profitability of the pipeline construction services business requiring field visits to construction projects and quality reviews. In this process, Mr. Coppola learned firsthand how pipeline construction companies operate, construction project challenges, their bidding practices and the bidding of construction projects, including pricing, bidding procedures and policies both from the contractor's side and the gas utility side.

Mr. Coppola has testified extensively on gas utility pipeline, service lines and inside meters replacement programs related to at-risk pipes that provide safety issues to customers and the general public.

In his role as Treasurer and Chairman of the MCN/MichCon Risk Committee from 1996 through 1998, Mr. Coppola was involved in reviewing and deciding on the appropriate gas purchase price hedging strategies, including the use of gas future contracts, over the counter swaps, fixed price purchases, and index price purchases.

In March 2001, Mr. Coppola testified before the Michigan House Energy and Technology Subcommittee on Natural Gas Fixed Pricing Mechanisms. Mr. Coppola frequently participates in natural gas issue forums sponsored by the American Gas Association and stays current on various energy supply issues through review of industry analyst reports and other publications issued by various trade groups.

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Mr. Coppola performed rate case analyses and filed testimony in several electric general rate cases addressing issues on revenue requirement, sales level determination, operation and maintenance expenses, capital expenditures, cost allocations, cost of capital, cost of service and rate design, and various cost tracking mechanisms. In addition, he has performed analysis of power costs and filed testimony in power supply cost recovery cases, including reconciliation of annual power supply costs.

In his position as Senior Vice President of Finance at MCN, Mr. Coppola also had responsibility for project financing of independent power generation plants in which MCN was an owner. In this regard, he was intricately involved and became knowledgeable of PURPA qualified cogeneration plants in Michigan and other states. In addition, he was involved in negotiating the development and financing of power generation and electricity distribution plants in other countries, such as India.

➤ Specific Regulatory Proceedings and Related Experience:

- Filed testimony on behalf of the Michigan Attorney General in Consumers Energy Company (CECo) 2025 gas rate case U-21981 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas Company (DTE Gas) 2024-2025 GCR reconciliation in case No. U-21440.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2025 gas rate case U-21973 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Electric Company (DTEE) 2024 PSCR reconciliation in Case No. U-21426.

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- Filed testimony on behalf of the Michigan Attorney General in CEC Co proposed sale of hydroelectric power generating assets in Case No. U-21985.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO Energy Gas Company (SEMCO) 2024-2025 GCR plan reconciliation in Case No. U-21446.
- Filed testimony on behalf of the Michigan Attorney General in Consumers Energy Company (CECo) 2024 PSCR reconciliation in Case N-. U-21424.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 2025 electric rate case U-21870 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2025 electric rate case U-21860 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2025-2026 GCR plan case No. U-21608.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2023-2024 GCR reconciliation in case No. U-21272.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2023 PSCR Plan Case No. U-21594.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 2024 electric rate case U-21806 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in Michigan Gas Utilities Corporation (MGUC) 2023-2024 GCR reconciliation in case No. U-21274.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2023 PSCR reconciliation in case No. U-21260.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 2023-2024 GCR reconciliation in case No. U-21270.

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- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2023-2024 GCR plan reconciliation in case No. U-21278.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2023 PSCR reconciliation in case No. U-21258.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2024 electric rate case U-21585 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2024 electric rate case U-21534 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in the Upper Peninsula Power Company (UPPCO) 2024 gas rate case U-21555 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2024 gas rate case U-21540 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2023-2024 GCR plan in case No. U-21277.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2024 gas rate case U-21291 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2022-2023 GCR reconciliation in case No. U-21065.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2023 gas rate case U-21490 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.

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- Filed testimony on behalf of the Michigan Attorney General in DTM Michigan Lateral Company (DMLC) 2023 Act 9 Transportation Service rate update in case No. U-21525.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2022 PSCR reconciliation in case No. U-21051.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2022-2023 GCR plan in case No. U-21067.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 2023 PSCR reconciliation in case No. U-21049.
- Filed testimony on behalf of the Michigan Attorney General in Indiana Power Company 2023 electric rate Case U-21461 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE 2023-2024 GCR plan in case No. U-21271.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 2023-2024 GCR plan in case No. U-21269.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 2023 electric rate Case U-21389 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2023-2024 GCR plan in case No. U-21277.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2023 rate Case U-21297 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2023-2024 GCR plan in case No. U-21273.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 2022 gas rate Case U-21308 on several issues, including sales revenues, operation and maintenance expenses, capital expenditures, cost of capital, and other items.

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- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2021-2022 GCR plan reconciliation case No. U-20817.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2021 PSCR plan reconciliation case No. U-20827.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2021-2022 GCR plan reconciliation case No. U-20819.
- Filed testimony on behalf of the Michigan Attorney General in Upper Peninsula Power Company 2022 general rate case No. U-21286.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2021-2022 GCR plan reconciliation case No. U-20823.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 2022-2023 GCR plan case No. U-21062.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2022-2023 GCR plan case No. U-21070.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 2022 electric rate Case U-21224 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Public Counsel Division of Washington Attorney General in the Avista 2022 electric and gas rate cases on several issues, including operation and maintenance expenses, capital expenditures, and other items.
- Filed testimony on behalf of the Michigan Attorney General in the Act 9 application in Case No. U-20993 by Saginaw Bay Pipeline Company to set transportation rates for services to DTE Gas Company.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2022 electric rate Case U-20836 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed rebuttal testimony on behalf the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Peoples Gaslight & Coke Company (Peoples Gas) in Docket 17-0137.

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- Filed testimony on behalf of the Michigan Attorney General in CECO 2021 gas rate Case U-21148 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2020-2021 GCR plan reconciliation case No. U-20554.
- Filed rebuttal testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Northern Illinois Gas Company (Nicor Gas) in Docket 20-0330.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2020-2021 GCR plan reconciliation case No. U-20552.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2020-2021 GCR plan reconciliation case No. U-20546.
- Filed testimony on behalf of the Michigan Attorney General in CECO 2020 PSCR plan reconciliation case No. U-20526.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2020 PSCR plan reconciliation case No. U-20528.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2019-2020 GCR plan reconciliation case No. U-20236.
- Filed rebuttal testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Ameren Illinois Company (Ameren) in Docket 20-0323.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2021-2022 GCR plan case No. U-20816.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2021-2022 GCR plan case No. U-20822.
- Filed testimony on behalf of the Michigan Attorney General in CECO 2021 electric rate Case U-20963 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.

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- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2021 gas rate Case U-20940 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Michigan Lateral Company (DMCL) 2021 Act 9 filing to convert a pipeline and build two interconnections for transportation services to DTE Gas Company in case No. U-20894.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2021 power plant and tree trimming securitization costs in case No. U-21015
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 2021 PSCR plan case No. U-20802.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 2019-2020 GCR reconciliation case No. U-20234.
- Filed testimony on behalf of the Maryland Office of Public Counsel in Washington Gas Light Company's 2020 rate Case 9651 on several issues, including operation and maintenance expenses, capital expenditures, and other items.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 2020 Karn 1 & 2 Retirement Cost and Bond Securitization Case U-20889.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2019 PSCR Reconciliation in case U-20222.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2020-2021 GCR plan case No. U-20543.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO Gas Company (SEMCO) 2020-2021 GCR plan case No. U-20551.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 2020 electric rate Case U-20697 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.

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- Filed testimony on behalf of the Michigan Attorney General in in the complaint against Upper Peninsula Power Company's (UPPCO) Revenue Decoupling Mechanism (RDM) in Case No. U-20150.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2019 gas rate Case U-20650 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas Company 2019 gas rate Case U-20642 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2018-2019 GCR reconciliation Case U-20210.
- Prepared a report on the financial condition and risks of AltaGas and Washington Gas Light Company on behalf of the Maryland Office of People's Counsel filed with the Maryland Public Service Commission in July 2019 in Case No. 9449.
- Filed rebuttal testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Northern Illinois Gas Company (Nicor Gas) in Docket 19-0294.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2018-2019 GCR reconciliation case U-20209.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2018-2019 GCR reconciliation case U-20215.
- Provided assistance and proposals to the Maryland Office of Peoples Counsel on Multi-Year Rate Plans and Performance-Based Ratemaking.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2018 PSCR Reconciliation in case U-20203.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2018 PSCR Reconciliation in case U-20202.
- Filed direct testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure

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Program (Rider QIP) of the Northern Illinois Gas Company (Nicor Gas) in Docket 19-0294.

- Filed testimony on behalf of the Michigan Attorney General in DTEE 2019 electric rate Case U-20561 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in Indiana Michigan Power Company (I&M) 2019 electric rate Case U-20239 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2019 gas rate Case U-20479 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2019-2020 GCR Plan case U-20245.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 2019-2020 GCR Plan case U-20233.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2019 PSCR Plan case U-20221.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2019-2020 GCR Plan case U-20235.
- Filed testimony on behalf of the Michigan Attorney General in Michigan Gas Utilities Corporation (MGUC) 2019-2020 GCR plan case U-20239.
- Filed rebuttal testimony on behalf of the Illinois Attorney General in Nicor Gas 2018 rate case on capital expenditures and rate base additions in Docket 18-1775.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2017-2018 GCR reconciliation case U-20076.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 2017-2018 GCR reconciliation case U-20075.

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- Filed testimony on behalf of the Michigan Attorney General in CEC Co 2018 gas rate Case U-20322 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in I&M Tax Credit C Calculation in case U-20317.
- Filed direct testimony on behalf of the Illinois Attorney General in Nicor Gas 2018 rate case on capital expenditures and rate base additions in Docket 18-1775.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas Tax Credit C Calculation in case U-20298.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2017-2018 GCR Reconciliation case U-20078.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co Tax Credit C Calculation for the Gas and Electric Divisions in case U-20309.
- Filed testimony on behalf of the Michigan Attorney General in Upper Peninsula Power Company 2018 electric rate Case U-20276 on several issues, including excess deferred taxes, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 2017 PS CR Reconciliation in case U-20068.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2018 rate Case U-20162 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 2018 Tax Credit B refund for the Electric Division in case U-20286.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 2018 Integrated Resource Plan in case U-20165.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 2018 Tax Credit B refund case U-20287 for the natural gas business.

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- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2018 Tax Credit B refund case U-20189.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 2018 electric rate Case U-20134 on several issues, including capital expenditures, cost of capital, rate design and other items.
- Filed direct testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Peoples Gas and Coke Company's (Peoples Gas) in Docket 16-0197.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2016-2017 GCR reconciliation case U-17941-R.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2018-2019 GCR Plan case U-18417.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 2018 Tax Credit A refund case U-20102.
- Filed testimony on behalf of the Michigan Attorney General in I&M 2018 PSCR Plan case U-18404.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2018-2019 GCR Plan case U-18412.
- Filed testimony on behalf of the Michigan Attorney General in Upper Peninsula Power Company (UPPCO) 2018 Tax Credit A refund case U-20111.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2018 Tax Credit A refund case U-20106.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2018 PSCR Plan case U-18403.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 2018 PSCR Plan case U-18402.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2017 gas rate Case U-18999 on several issues, including revenue, operations and maintenance costs, capital expenditures, cost of capital, rate design and other items.

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- Filed testimony on behalf of the Michigan Attorney General in CEC0 2017 gas rate Case U-18424 on several issues, including revenue, operations and maintenance costs, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2016 PSCR reconciliation case U-17918-R.
- Assisted the Michigan Attorney General in the review of several GCR and PSCR cases during 2017 and 2018, and proposed terms for settlement of those cases.
- Assisted the Michigan Attorney General in the filing of comments with the Michigan Public Service Commission relating to rate case filing requirements in case U-18238, refunds of tax savings from the lower federal tax rate in case U-18494 and Performance Based Regulation.
- Filed direct and rebuttal testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Peoples Gas and Coke Company's (Peoples Gas) in Docket 15-0209.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2017 electric Rate Case U-18255 on a several issues, including revenue, operations and maintenance costs, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2017 electric rate Case U-18322 on a several issues, including revenue, operations and maintenance costs, capital expenditure programs, cost of capital and other items.
- Filed direct and rebuttal testimony on behalf of the Illinois Attorney General for the re-opening of proceedings in the restructuring of the Peoples Gas's main replacement program and gas system modernization plan in Docket 16-0376.
- Filed testimony on behalf of the Michigan Attorney General in the Upper Michigan Energy Resources Corporation (UMERC) application for a certificate of public necessity and convenience to build two power plants in the Upper Peninsula of Michigan in case U-18202.

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- Filed testimony on behalf of the Michigan Attorney General in SEMCO application for a certificate of public necessity and convenience to build a pipeline in the Upper Peninsula of Michigan in case U-18202.
- Filed testimony on behalf of the Public Counsel Division of the Washington Attorney General in Puget Sound Energy's 2016 Complaint for Violation of Gas Safety Rules in Docket No. UE-160924.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2017 PSCR Plan case U-18143.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2015 Power Supply Cost Recovery (PSCR) reconciliation case U-17678-R.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2016 gas general rate case U-18124 on a several issues, including revenue, operations and maintenance costs, capital expenditures, working capital, cost of capital and other items.
- Filed testimony on behalf of the Illinois Attorney General for the restructuring of the Peoples Gas's main replacement program in Docket 16-0376.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2014-2015 GCR Plan reconciliation case U-17332-R.
- Filed testimony on behalf of the Michigan Attorney General in the formation of UMERL and the transfer of Michigan assets of Wisconsin Public Service Corporation and Wisconsin Electric Company to UMERL in Case U-18061.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 Court of Appeals Remand Case U-17087 for review of the Automated Meter Infrastructure (AMI) opt-out fees.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2016 electric Rate Case U-17990 on a several issues, including revenue, operations and maintenance costs, capital expenditure programs, cost of capital, rate design and other items.

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- Filed testimony on behalf of the Michigan Attorney General in Michigan Gas Utilities Corporation (MGUC) 2016-2017 GCR Plan case U-17940.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2016 electric Rate Case U-18014 on a several issues, including revenue, revenue decoupling, operations and maintenance costs, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2016-2017 GCR Plan case U-17942.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2016-2017 GCR Plan case U-17941.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2015 gas general rate case U-17999 on a several issues, including revenue, operations and maintenance costs, capital expenditures, main replacement program, Revenue Decoupling Mechanism (RDM) program, cost of capital and other items.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 2016-2017 GCR Plan case U-17943.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 2016 PSCR Plan case U-17918.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 2014-2015 GCR Plan reconciliation case U-17334-R.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2016 PSCR Plan case U-17920.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2014-2015 GCR Plan reconciliation case U-17333-R.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 2015 gas general rate case U-17882 on a several issues, including revenue, operations and maintenance costs, capital expenditures, main replacement program, infrastructure cost recovery mechanism, cost of capital and other items..
- Filed testimony on behalf of the Michigan Attorney General in CEC Co Gas Choice and End-User Transportation tariff changes case U-17900.

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- Analyzed the gas rate case filings of MGUC in Case U-17880 and assisted the Michigan Attorney General in settlement of the case.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2014 PSCR reconciliation case U-17317-R.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2013-2014 GCR Plan reconciliation case U-17131-R.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2014 electric Rate Case U-17767 on a several issues, including operations and maintenance costs, capital expenditures, AMI program, cost of capital and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2015-2016 GCR Plan case U-17691.
- Filed testimony on behalf of the Illinois Attorney General in Ameren Illinois Company's 2015 general rate case on operation and maintenance costs in Docket 15-0142.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2014 electric Rate Case U-17735 on a several issues, including sales, operations and maintenance costs, capital expenditures, cost of capital, AMI program, revenue decoupling and infrastructure cost recovery mechanisms.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2015-2016 GCR Plan case U-17693.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2015-2016 GCR Plan case U-17690.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2015 PSCR Plan case U-17678.
- Analyzed the electric rate case filings of Northern States Power in Case U-17710 and Wisconsin Public Service Company U-17669, and assisted the Michigan Attorney General in settlement of these cases.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2013-2014 GCR Plan reconciliation case U-17133-R.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2013-2014 GCR Plan reconciliation cases U-17130-R.

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- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2013-2014 GCR Plan reconciliation case U-17132-R.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 2014 gas general rate case U-17643 on a several issues, including revenue, operations and maintenance costs, capital expenditures, main replacement program, cost of capital and other items..
- Filed testimony on behalf of the Illinois Attorney General in Wisconsin Energy merger with Integrys on the Peoples Gas and Coke Company's Accelerated Main Replacement Program Docket 14-0496.
- Filed testimony on behalf of Citizens Against Rate Excess in Wisconsin Public Service Company's 2013 PSCR plan reconciliation case U-17092-R.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 2014 PSCR plan case U-17317.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 2014 OPEB Funding case U-17620.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2014-2015 GCR Plan case U-17333.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2014-2015 GCR Plan case U-17331.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 2014-2015 GCR Plan case U-17334.
- Filed testimony for Citizens Against Rate Excess in Wisconsin Public Service Company's 2014 PSCR plan case U-17299.
- Filed testimony in March 2013 on behalf of the Michigan Attorney General in CEC Co's electric Rate Case U-15645 on remand from the Michigan Court of Appeals for review of the AMI program.
- Filed testimony for Citizens Against Rate Excess in Upper Peninsula Power Company's 2012 PSCR plan case U-17298.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2012-2013 GCR Reconciliation case U-16920-R.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas Company 2012-2013 GCR Reconciliation case U-16921-R.

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- Filed testimony on behalf of the Michigan Attorney General in CEC0 2012-2013 GCR Reconciliation case U-16924-R.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2012-2013 GCR Reconciliation case U-16922-R.
- Filed testimony for Citizens Against Rate Excess in Upper Peninsula Power Company's 2012 Power Supply Cost Recovery (PSCR) reconciliation case U-16881-R.
- Filed testimony in Puget Sound Energy's 2013 Power Cost Only Rate Case on behalf of the Public Counsel Division of the Washington Attorney General in Docket No. UE-130167 on the power costs adjustment mechanism.
- Filed testimony in PacifiCorp's 2013 General Rate Case on behalf of the Public Counsel Division of the Washington Attorney General in Docket No. UE-130043 on power costs, cost allocation factors, O&M expenses and power cost adjustment mechanisms.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2013-2014 GCR Plan case U-17132.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2013-2014 GCR Plan case U-17130.
- Filed testimony on behalf of the Michigan Attorney General in CEC0's 2012 electric Rate Case U-17087 on a several issues, including cost of service methodology, rate design, operations and maintenance costs, capital expenditures and infrastructure cost recovery mechanism and other revenue/cost trackers.
- Filed reports on gas procurement and hedging strategies of four gas utilities before the Washington Utilities and Transportation Commission on behalf of the Washington Attorney General – Office of Public Counsel in April 2013.
- Filed testimony on behalf of the Michigan Attorney General in MGUC and SEMCO 2011-2012 GCR Plan reconciliation cases U-16481-R and U-16483-R.
- Filed testimony for Citizens Against Rate Excess in Upper Peninsula Power Company's 2012 Power Supply Cost Recovery (PSCR) plan case U-17091.

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- Filed testimony in MichCon’s 2012 gas Rate Case U-16999 on a several issues, including sales volumes, revenue decoupling mechanism, operations and maintenance costs, capital expenditures and infrastructure cost recovery mechanism.
- Filed testimony on behalf of the Washington Attorney General – Office of Public Counsel on executive and board of directors’ compensation in the 2012 Avista general rate case.
- Filed testimony for Citizens Against Rate Excess in Upper Peninsula Power Company’s 2011 Power Supply Cost Recovery (PSCR) reconciliation case U-16421-R.
- Filed testimony on behalf of the Ohio Office of Consumers Counsel in AEP Ohio’s power supply restructuring case in June 2012.
- Filed testimony on behalf of the Michigan Attorney General in MGUC and SEMCO 2012-2013 GCR Plan cases U-16920 and U-16922.
- Filed testimony for Citizens Against Rate Excess in Upper Peninsula Power Company’s 2012 PSCR plan case U-16881.
- Filed testimony for Citizens Against Rate Excess in Wisconsin Public Service Corporation’s 2012 PSCR plan case U-16882.
- Filed testimony for the Michigan Attorney General in CEC’s gas business Pilot Revenue Decoupling Mechanism in case U-16860.
- Filed testimony for the Michigan Attorney General in Consumers Energy Gas 2011 Rate Case U-16855 on several issues, including sales volumes, operations and maintenance cost, employee benefits, capital expenditures and cost of capital.
- Filed testimony for the Michigan Attorney General in SEMCO and MGUC 2010-2011 GCR Plan reconciliation cases U-16147-R and U-16145-R.
- Filed testimony for the Michigan Attorney General in Consumers Energy 2011 electric Rate Case U-16794 on several issues, including electric sales forecast, revenue decoupling mechanism, operations and maintenance cost, employee benefits, capital expenditures and cost of capital.
- Filed testimony for the Michigan Attorney General in CEC’s electric business Pilot Revenue Decoupling Mechanism in case U-16566.

Experience and Qualifications of Sebastian Coppola

- Filed testimony on behalf of the Michigan Attorney General in SEMCO and MGUC 2011-2012 GCR Plan cases U-16483 and U-16481.
- Filed testimony for the Michigan Attorney General in Detroit Edison 2010 electric Rate Case U-16472 on several issues, including revenue decoupling mechanism, operations and maintenance cost, executive compensation and benefits, capital expenditures and cost of capital.
- Filed testimony for the Michigan Attorney General in SEMCO 2009-2010 GCR reconciliation case U-15702-R.
- Filed testimony for Michigan Attorney General in MGUC 2009-2010 GCR reconciliation case U-15700-R.
- Filed testimony for Michigan Attorney General, in Consumers Energy Gas 2010 Rate Case U-16418 on several issues, including sales volumes, operations and maintenance costs, capital expenditures and cost of capital.
- Filed testimony for Michigan Attorney General, in SEMCO 2010 Rate Case U-16169 on several issues, including sales volumes, rate design, operations and maintenance cost, executive compensation and benefits, capital expenditures and cost of capital.
- Filed testimony, for Michigan Attorney General in Consumers Energy 2009 electric Rate Case U-16191 on several issues, including sales volumes, revenue decoupling mechanism, operations and maintenance cost and capital expenditures.
- Filed testimony for Michigan Attorney General, in MichCon 2009 gas Rate Case U-15985 on several issues, including sales volumes, revenue decoupling mechanism, operations and maintenance cost, capital expenditures and cost of capital.
- Filed testimony for Michigan Attorney General and was cross-examined in Consumers Energy 2009 gas Rate Case U-15986 on several issues, including sales volumes, revenue decoupling mechanism, operations and maintenance cost, capital expenditures and cost of capital.
- Prepared testimony and assisted the Michigan Attorney General in discussions and settlement of SEMCO and MGUC 2010-2011 GCR Plan cases U-16147 and U-16145.

Experience and Qualifications of Sebastian Coppola

- Prepared testimony and assisted Michigan Attorney General in settlement of SEMCO 2009-2010 GCR case U-15702.
- Prepared testimony and assisted Michigan Attorney General in settlement of MGUC 2009-2010 GCR case U-15700.
- Prepared testimony and assisted the Michigan Attorney General in discussions and settlement of SEMCO 2008-2009 GCR case U-15452 and reconciliation case U-15452-R.
- Prepared testimony and assisted Michigan Attorney General in discussions and settlement of MGUC 2008-2009 GCR reconciliation case U-15450-R.
- Prepared testimony for Michigan Attorney General in SEMCO GCR 2007-2008 Reconciliation Case U-15043-R.
- Prepared testimony for Michigan Attorney General filed in MGUC 2007-2008 GCR Reconciliation Case U-15040-R.
- Participated in drafting of testimony for all aspects of SEMCO rate case filing with the Regulatory Commission of Alaska (RCA) in 2001.
- Filed testimony in 2001 before the (RCA) and was cross-examined on the financing plans for the acquisition of Enstar Corporation and the capital structure of SEMCO.
- Developed a cost of capital study in support of testimony by company witness in the Saginaw Bay Pipeline Company rate request proceeding in 1989.
- Prepared testimony for company witness on cost of capital and capital structure in MichCon 1988 gas rate case.
- Filed testimony in MichCon gas conservation surcharge case in 1986-87.
- Testified before MPSC ALJ in MichCon customer bill collection complaints in 1983.
- Participated in analysis of uncollectible gas accounts expense for inclusion in rate filings between 1975 and 1988.
- Participated in analysis of allocation of corporate overhead to subsidiaries and use of the “Massachusetts Formula” at MichCon and at SEMCO in 1975 and 2000.

Experience and Qualifications of Sebastian Coppola

- Prepared support information on GCR and rate case-O&M testimony at MichCon from 1975 to 1988.
- Filed testimony in MichCon financing orders in 1987 and 1988.
- Participated in rate case filing strategy sessions at MichCon and SEMCO from 1975 to 2001.
- Provided Hearing Room assistance and guidance to counsel on financial and policy issues in various cases from 1975 to 2001.

EDUCATIONAL BACKGROUND

Mr. Coppola did his undergraduate work at Wayne State University, where he received the Bachelor of Science degree in Accounting in 1974. He later returned to Wayne State University to obtain his Master of Business Administration degree with major in Finance in 1980.



1 MR. WOLLENZIEN: Thank you, your Honor.

2 I also want to confirm, I believe I moved for admission
3 of Exhibit AG-8 during cross of Witness Foley, but I just
4 want to confirm that that got entered.

5 COURT REPORTER: Yes.

6 JUDGE STALEY: Did it? Yes, it did. It
7 did, yes.

8 MR. WOLLENZIEN: Thank you. Thank you,
9 your Honor, thank you, Ms. Penn. And finally, I'd also
10 move to have bound in at this time the Attorney General's
11 Exhibit AG-7 comprised of certain discovery responses
12 from DTE as was circulated in a proposal to the parties
13 via email on June 29, and I did not upload that to the
14 hearing exhibit, but I can do that right now.

15 JUDGE STALEY: And that's AG-7?

16 MR. WOLLENZIEN: That's correct, your
17 Honor.

18 JUDGE STALEY: All right. Is there any
19 objection to the admission of hearing room Exhibit AG-7?

20 MR. JANISZEWSKI: Your Honor, as long --

21 JUDGE STALEY: All right. Hearing
22 none --

23 MR. JANISZEWSKI: Sorry. As long as it
24 reflects what was previously agreed to, which I have all
25 confidence it will, there is no concern from the Company.

1 JUDGE STALEY: O.K. And Mr. Wollenzien,
2 you represent that it is an accurate depiction of what
3 the parties have agreed to?

4 MR. WOLLENZIEN: Yes, your Honor. I had
5 forwarded, I believe counsel for DTE had referenced a
6 stipulation to waiver of some witnesses, and I had sent a
7 proposed exhibit, I just forgot to upload it to the
8 hearing room this morning. But I mean I'm happy to do
9 that right now, but it will just be the exact same thing
10 I forwarded to DTE and the parties, it will just be
11 copying and pasting the same documents essentially.

12 JUDGE STALEY: Are you satisfied with
13 that, Mr. Janiszewski?

14 MR. JANISZEWSKI: Yes, your Honor. Thank
15 you.

16 JUDGE STALEY: All right. Then hearing
17 room Exhibit AG-7 is admitted into evidence. Does that
18 conclude the Attorney General's case?

19 MR. WOLLENZIEN: Yes, your Honor. Thank
20 you. No further material to bind in right now. Thank
21 you.

22 JUDGE STALEY: O.K. Thank you. And then
23 Mr. Campbell, on behalf of ABATE.

24 MR. CAMPBELL: Thank you, your Honor. At
25 this time, I'd move to bind in the Direct Testimony of
Penn Reporting, LLC - lori.penn@yahoo.com

1 ABATE Witness James Dauphinais and for the admission of
2 his associated exhibits, and I note Mr. Dauphinais had
3 both a Public and Confidential version of his direct
4 testimony. Mr. Dauphinais's prefiled direct testimony
5 consists of a cover page, a table of contents, 29 pages
6 of questions and answers, and an Appendix A setting out
7 his qualifications; and along with his direct testimony,
8 Mr. Dauphinais sponsored Exhibits AB-1 and AB-2. Also,
9 pursuant to consent or non-objection of the parties, I'd
10 move to admit Exhibit AB-3, which consists of certain
11 discovery responses from the Company which were served on
12 the parties previously.

13 JUDGE STALEY: All right. Is there any
14 objection to the binding in of the prefiled Direct
15 Testimony of James R. Dauphinais, with a Confidential and
16 Public version, as well as Appendix A, or the admission
17 of Exhibits AB-1, AB-2, and Hearing Room AB-3?

18 MR. JANISZEWSKI: Your Honor --

19 JUDGE STALEY: Hearing none. I'm sorry.

20 MR. JANISZEWSKI: I'm sorry, I don't mean
21 to slow down the process. I just don't see a folder in
22 the SharePoint for ABATE. Similar to what was
23 represented regarding Exhibit AG-7, as long as Exhibit
24 AB-3 reflects what was agreed to, and certainly don't
25 have any concerns regarding the admission of that, I just

1 don't see anything in the SharePoint at this time.

2 JUDGE STALEY: Mr. Campbell, do you
3 represent that the hearing room Exhibit AB-3 reflects the
4 document agreed to by the parties?

5 MR. CAMPBELL: It does, yes. I'm sorry
6 if there's an issue with the SharePoint, I can correct
7 that if that wasn't set up.

8 JUDGE STALEY: Any objection to the
9 binding in of the Testimony, Confidential and Public, of
10 James R. Dauphinais, as well as his Appendix A, and
11 admission of Exhibits AB-1, AB-2, and AB-3?

12 Hearing none, the prefiled Direct
13 Testimony, Confidential as well as Public versions of the
14 Testimony of James R. Dauphinais are bound into the
15 record, as well as Appendix A, and Exhibits AB-1, AB-2,
16 and AB-3 are admitted into evidence.

17 (Public Direct Testimony bound in.)

18 - - -

19 (Confidential Direct Testimony found on Page 924 of
20 the Confidential Record.)

21 - - -

**STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION**

**In the Matter of the Application of
DTE ELECTRIC COMPANY for approval of
special contracts and for other relief.**

)
)
)
)
Case No. U-22058

PUBLIC VERSION

Direct Testimony of

James R. Dauphinais

On behalf of

Association of Businesses Advocating Tariff Equity

June 5, 2026



Project 12048

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the Matter of the Application of DTE ELECTRIC COMPANY for approval of special contracts and for other relief.	))))	Case No. U-22058

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Direct Testimony of James R. Dauphinais**

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Appendix A: Qualifications of James R. Dauphinais

Exhibit AB-1: Referenced DTE Responses to Discovery Requests

Exhibit AB-2: Remaining Net Revenue Requirement – Proxy CCGT with CCS and Solar –
Capacity and Energy Value Maintained at 2038 Level

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the Matter of the Application of DTE ELECTRIC COMPANY for approval of special contracts and for other relief.	))))	Case No. U-22058

Direct Testimony of James R. Dauphinais

I. INTRODUCTION

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A James R. Dauphinais. My business address is 16690 Swingley Ridge Road, Suite 140,
Chesterfield, MO 63017.

Q WHAT IS YOUR OCCUPATION?

A I am a consultant in the field of public utility regulation and a Managing Principal with
the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory
consultants.

Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A This information is included in Appendix A to my testimony.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am appearing on behalf of the Association of Businesses Advocating Tariff Equity
("ABATE"). ABATE consists of large usage customers that purchase substantial
amounts of electric power and/or delivery service from DTE Electric Company ("DTE")

1 or the "Company"). They primarily take service under DTE Rate D8, Rate D11, Rider
2 3 and/or Rider 10.

3 **Q HAVE YOU PRESENTED TESTIMONY IN PRIOR ELECTRIC REGULATORY**
4 **PROCEEDINGS BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION**
5 **("COMMISSION" or "MPSC")?**

6 A Yes. Over my 28 years of employment by BAI, I have provided testimony to the
7 Commission on several occasions regarding issues that include electric rate design,
8 class cost of service, Power Supply Cost Recovery ("PSCR"), standby service rates,
9 resource planning, transmission planning and transmission line routing. In recent
10 years, this has included providing testimony in the most recent general rate cases of
11 Consumers Energy Company (Case Nos. U-20963, U-21224, U-21389, U-21585 and
12 U-21870), DTE (Case Nos. U-18014, U-18255, U-20162, U-20561, U-20836, U-21297,
13 U-21534 and U-21860) and Indiana Michigan Power Company (Case Nos. U-18370,
14 U-20359 and U-21461), as well as in the original Section 6w State Reliability
15 Mechanism ("SRM") Capacity Charge proceedings of Consumers (Case No. U-18239)
16 and DTE (Case No. U-18248). I also provided testimony in the 2020 PSCR
17 Reconciliation cases of Consumers (Case No. U-20526) and DTE (Case No. U-20528),
18 as well as the most recent Integrated Resource Plan ("IRP") proceedings of Consumers
19 (Case No. U-21090), DTE (Case No. U-21193) and Indiana Michigan Power Company
20 (Case No. U-21189). Additionally, I provided testimony in the large load addition tariff
21 amendment cases of Consumers (Case No. U-21859) and Indiana Michigan Power
22 Company (Case No. U-21986). Most recently, I provided testimony in the proceeding
23 relative to Consumers' application to revise its Voluntary Green Pricing ("VGP")
24 programs (Case No. U-21972).

1 **Q WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

2 **A** The purpose of my testimony is to respond to DTE's application in this proceeding,
3 which has requested: (i) Commission approval of two special contracts (a Primary
4 Supply Agreement ("PSA") and a Clean Capacity Acceleration Agreement ("CCAA"))
5 between DTE and Google LLC ("Google" or "Customer") under which Google would
6 take electric service from DTE pursuant to DTE Rate Schedule D11 for a data center
7 facility with a maximum demand of approximately 1.0 GW (1,000 MW) located at or
8 near Van Buren Township, Michigan; (ii) Commission authorization for DTE to record
9 to income a financial incentive that would be paid by Google to DTE for Zonal Resource
10 Credits ("ZRC") transferred by Google to DTE under the CCAA; and (iii) Commission
11 authorization to record regulatory liabilities to Account 254 for the accelerated recovery
12 for storage and renewable energy projects under the CCAA.¹

13 While DTE is not requesting approval of them in this proceeding, DTE in its
14 direct testimony identifies two additional agreements between DTE and Google – a
15 DTE Rider 12 Demand Response ("DR") Agreement and a Line Extension Agreement
16 ("LEA"). DTE relies upon these two additional agreements in its direct testimony to
17 help support its contention that the PSA and CCAA are reasonable, prudent, in the
18 public interest, and will not increase the cost of service to other customers.² Therefore,
19 I also address both of these agreements in that context in my testimony herein.

20 My silence with respect to any position taken by DTE in its application or direct
21 testimony in this proceeding should not be interpreted as an endorsement of that
22 position.

¹ Application at 1-2 and 6.

² DTE Witness Foley Revised Direct at NTF-6.

1 **Q PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS IN THIS**
2 **PROCEEDING.**

3 A Based on my review of DTE's application, direct testimony and exhibits, and responses
4 to discovery as of the filing date of my testimony herein, for the following reasons, I
5 have concluded DTE's proposed PSA and CCAA are insufficient as filed to ensure
6 DTE's provision of electric service to Google would be reasonable, prudent, in the
7 public interest, and will not increase the cost of service to other customers:

- 8 • DTE'S net benefit analysis has significant limitations and is not by itself
9 sufficient to show that DTE providing service to Google under the PSA and
10 CCAA would not ultimately cause DTE's other customers to see higher
11 costs.
- 12 • DTE's proposed Affordability Backstop under its proposed PSA with Google
13 (Section 5.1.3 of the PSA) does not extend beyond termination of the PSA
14 and does not provide for modification of the termination payment under the
15 PSA in the event the Commission finds the aggregate costs of serving
16 Google exceed the aggregate benefits.
- 17 • DTE is unwilling to commit to not seeking recovery from its other customers
18 for any amount owed by Google to DTE under the PSA and CCAA.
- 19 • DTE has not made a commitment to fully utilize the discretion given to it
20 under Section 2 of the PSA to limit the load ramp and maximum demand of
21 Google to ensure resource adequacy for its other customers.
- 22 • DTE's proposal to serve the Google facility under the PSA and CCAA relies
23 on a yet to be identified, large new generation resource addition entering
24 service prior to the end of Google's CCAA ZRC transfer commitment and
25 the Rider 12 DR Agreement commitment on May 31, 2033, which places an
26 undue problematic resource adequacy risk on DTE's other customers.
- 27 • DTE's proposal to serve the Google facility via DTE's Rate D11 would distort
28 the characteristics of the D11 customer class and, as a result, will likely lead
29 to intra-class subsidies, given that the Google facility would likely make up
30 approximately 26% of DTE's total full service sales in the D11 class upon
31 the completion of Google's ramp up, and, in conjunction with DTE's other
32 large data center load customer, Oracle America Cloud Services LLC
33 ("Oracle", formerly Green Chile Ventures LLC), would likely make up
34 approximately 62% of DTE's total full service sales in the D11 class.
- 35 • DTE's proposal to receive a financial incentive from Google for the ZRCs
36 that would be transferred by Google to DTE under the proposed CCAA is
37 inappropriate given that the transfer of the ZRCs to DTE is not the same as

1 the acquisition of power under a Purchased Power Agreement ("PPA"), and
2 would instead amount to DTE being allowed to earn a monopoly rent on
3 customer self-supplied capacity.

4 Given these conclusions, I recommend that the Commission reject DTE's
5 proposed PSA and CCAA as filed by DTE and, at a minimum, condition any approval
6 of the PSA and CCAA on DTE and Google agreeing to the following:

- 7 • Modification of the Affordability Backstop provision under Section 5.1.3 of
8 the proposed PSA to allow an evaluation and modification of the termination
9 payment based on the facts and circumstances known or knowable at the
10 time of termination. The Affordability Backstop must ensure the costs
11 incurred to serve Google do not exceed the benefits from serving Google
12 due to the termination, giving full consideration to the reasonably projected
13 forward-looking benefits at that time compared with any sunk costs incurred
14 by DTE to serve Google.
- 15 • In the event of a failure by Google to pay any amount due to DTE under the
16 PSA or CCAA, or in the event of a termination, default, or other event
17 whereby DTE is required to draw on the letters of credit or parental
18 guaranties under the PSA or CCAA, if DTE determines that the specified
19 collateral is not sufficient to cover the full amount of the remaining financial
20 exposure associated with the PSA or CCAA (minus the value to customers),
21 any unrecovered costs shall not be borne by ratepayers and DTE shall bear
22 responsibility for any remaining liability.
- 23 • DTE shall fully utilize the discretion given to it under Section 2 of the PSA
24 to limit the load ramp and maximum demand of Google as necessary to
25 ensure resource adequacy for DTE's other customers.
- 26 • DTE modifying its emergency procedures to subject Google to firm load
27 shedding prior to other customers, provided that such customer load
28 shedding does not: (i) compromise system reliability; and (ii) can prevent
29 shedding firm load of other DTE Electric Customers, until such time all of
30 the resources necessary to serve the Google data center load are in
31 service.
- 32 • Modification of the CCAA and the Rider 12 DR Agreement such that:
33 (i) Google is required to continue to transfer 300 MW of ZRCs to DTE
34 beyond May 31, 2033; and (ii) Google's facility is required to continue to be
35 curtailable down to a demand of 650 MW beyond May 31, 2033, to the
36 extent DTE has been unable to bring 550 MW of ZRCs of new capacity
37 online in MISO Zone 7 to replace the ZRCs provided by Google to DTE
38 under the CCAA and Rider 12 DR Agreement.
- 39 • Modification of the proposed PSA to place Google into its own customer
40 class, potentially with other large data center loads, but separate and apart

1 from the Rate D11 class, with the initial rates for the class being the same
2 as those for Rate D11.

- 3 • DTE withdrawing its proposal to earn a financial incentive on the ZRC
4 transfer by Google to DTE under the CCAA or, in the alternative, DTE
5 agreeing that the Commission's approval of Google's agreement under the
6 CCAA to provide a financial incentive to DTE for the ZRC transfer does not
7 set any precedent with respect to whether DTE is entitled to mandate the
8 receipt of such a financial incentive from its customers on customer
9 self-supplied capacity and energy.

10 **II. SUMMARY OF DTE'S PROPOSAL TO SERVE GOOGLE**

11 **Q PLEASE PROVIDE A SUMMARY OF DTE'S PROPOSAL IN THIS PROCEEDING TO**
12 **PROVIDE ELECTRIC SERVICE TO GOOGLE'S PROPOSED 1.0 GW DATA**
13 **CENTER LOAD TO BE LOCATED AT OR NEAR VAN BUREN TOWNSHIP.**

14 **A** Pursuant to its PSA and CCAA with Google for which DTE has requested Commission
15 approval for in this proceeding, and in conjunction with DTE's Rider 12 DR Agreement
16 and LEA with Google for which DTE is not seeking Commission approval, DTE
17 proposes to provide electric service to Google as a full-service customer under DTE
18 Rate D11. Rate D11 is currently the principal electric service rate used to provide
19 electric service to DTE's commercial and industrial customers served at primary or
20 higher voltage. Putting aside the 1.4 GW Oracle data center load that was the subject
21 of Case No. U-21990, the 1.0 GW Google data center load would be by far the largest
22 single full-service customer taking electric service under Rate D11. Based on the Rate
23 D11 rate design workpapers for the Final Order in U-21534 (provided by DTE in
24 response to Data Request ABDE-1.4),³ DTE's total current full-service customer load
25 on Rate D11 is approximately 1.8 GW with a 73.4% load factor spread over

³ A copy of DTE data request responses (without their voluminous attachments), can be found in Exhibit AB-1 in alphanumeric order.

2,079 customers.⁴ In contrast, Google, if its load fully materializes, would as a single customer have a demand of approximately 1.0 GW with an expected load factor of approximately 90%.⁵ Assuming the Oracle data center also has a load factor of approximately 90% and there is no load growth in traditional D11 full-service customers, Oracle and Google together would make up approximately 57% of the total full-service demand and approximately 62% of the total full-service energy in the D11 rate class.⁶ Google alone would account for approximately 24% of the total full-service demand and 26% of the total full-service energy in the D11 rate class.⁷

Q PLEASE PROVIDE A SUMMARY OF THE MAJOR ELEMENTS OF THE PSA.

A The PSA would provide Google electric service under DTE Rate Schedule D11 for a period of 20 years and would automatically renew for up to two additional five-year terms unless Google provides at least 36 months' notice of non-renewal.⁸

Under the PSA, Google would pay all surcharges applicable to Rate D11, including the PSCR surcharge, and its ability to switch to a different rate schedule would be restricted such that it could not request a change taking effect prior to 24 months after its Load Ramp Completion Date, must provide 24 months' notice, and could only move to a Commission-approved rate schedule that is not cross-subsidized by any other customer group.⁹

⁴ DTE Response to ABDE-1.4, U-22058 ABDE-1.4 U-21534 Approved Rate Design Model.xlsx at D11 Total Tab, Line 1, 9 and 30; $1.8 \text{ GW} \approx 1.788 \text{ GW} = 21,460,521 \text{ kW} / 1,000,000 \text{ kW per GW} / 12 \text{ months per year}$; $73.4\% \text{ load factor} = 11,505,383 \text{ MWh} / [(21,460,521 \text{ kW} / 1,000 \text{ kW per MW} / 12 \text{ months per year}) \times 8,760 \text{ hours per year}]$.

⁵ Application at 2 and DTE Witness Bilyeu Direct at KLB-11; $90\% \approx 89.95\% = 7.88 \text{ TWh} / [(1.0 \text{ GW} / 1,000 \text{ GW per TW}) \times 8,760 \text{ hours}]$.

⁶ $57\% \approx 57.14\% = (1.4 \text{ GW} + 1.0 \text{ GW}) / (1.8 \text{ GW} + 1.4 \text{ GW} + 1.0 \text{ GW})$; $61\% \approx 62.05\% = [(1.4 \text{ GW} + 1.0 \text{ GW}) \times 90\%] / [1.8 \text{ GW} \times 73.4\% + (1.4 \text{ GW} + 1.0 \text{ GW}) \times 90\%]$.

⁷ $24\% \approx 23.81\% = (1.0 \text{ GW}) / (1.8 \text{ GW} + 1.4 \text{ GW} + 1.0 \text{ GW})$; $26\% \approx 25.85\% = (1.0 \text{ GW} \times 90\%) / [1.8 \text{ GW} \times 73.4\% + (1.4 \text{ GW} + 1.0 \text{ GW}) \times 90\%]$.

⁸ Application at 2-3 AND DTE Witness Foley Revised Direct at NTF-11 through NTF-12.

⁹ DTE Witness Foley Revised Direct at NTF-12 through NTF-13.

1 The PSA establishes a Minimum Billing Demand (“MBD”) equal to 80% of
2 Google’s contract capacity applicable for a given billing period, which would equal
3 800 MW once Google reaches its full 1,000 MW contract capacity.¹⁰ Based on the D11
4 rates approved in Case No. U-21860, DTE indicates this MBD would result in a
5 Minimum Monthly Charge (“MMC”) of approximately \$13.8 million per month, that
6 Google would owe regardless of whether its actual usage ever reaches its contract
7 capacity.¹¹ While Google may temporarily delay its load ramp by up to 18 months in
8 the aggregate, which could push its Load Ramp Completion Date as late as June 2030,
9 the PSA provides that Google cannot reduce the contract capacity that DTE has
10 committed to serve once the load ramp is reached.¹²

11 The PSA also addresses circumstances in which DTE is unable to achieve or
12 maintain Google’s load ramp or maximum load — including termination of the CCAA
13 or Rider 12 DR Agreement, reasons not attributable to DTE, Google’s
14 underperformance or nonperformance, or a determination that the energy storage
15 portfolio under the CCAA is not feasible — in which case the parties would negotiate a
16 solution and, failing agreement, DTE could unilaterally propose an adjustment to
17 Google’s load ramp or maximum load that Google could accept or else terminate the
18 PSA and pay all applicable termination payments.¹³ The PSA contains a termination
19 payment that DTE indicates is designed so that DTE will recover at least 15 years of
20 MMCs once Google achieves its maximum load, with the termination payment at the
21 Load Ramp Completion Date equal to approximately \$2.48 billion based on the D11
22 rate approved in Case No. U-21860.¹⁴

¹⁰ DTE Witness Foley Revised Direct at NTF-13 through NTF-14.

¹¹ DTE Witness Foley Revised Direct at NTF-15.

¹² DTE Witness Foley Revised Direct at NTF-15 through NTF-16.

¹³ DTE Witness Foley Revised Direct at NTF-16 through NTF-17.

¹⁴ DTE Witness Foley Revised Direct at NTF-17 through NTF-18.

1 In the PSA, Google also commits to participate in and comply with the
2 self-directed energy waste reduction plan requirements set forth in MCL 460.1093.¹⁵

3 Furthermore, the PSA includes an Affordability Backstop, set forth in Section
4 5.1.3 of the PSA, under which Google agrees that if, at any time during the term, the
5 Commission issues a ruling or order determining that the costs to serve Google exceed
6 the combined revenues paid or payable to DTE under the PSA and the applicable
7 Related Agreements, or disallows DTE's recovery of costs attributable to serving
8 Google, Google will comply with any such ruling or order and, as applicable, reimburse
9 DTE for any unrecovered costs, except for unrecovered costs incurred due to DTE's
10 gross negligence or willful misconduct.¹⁶ DTE in discovery indicated that this would
11 include consideration of: (i) all revenue received under the PSA and CCAA; (ii) any
12 avoided revenue requirement associated with resources that DTE was able to avoid
13 deploying due to serving Google under the PSA and CCAA; (iii) the revenue
14 requirement of the energy storage projects under the CCAA; (iv) the revenue
15 requirement of renewable energy projects under the CCAA; (v) the revenue
16 requirement of the renewable energy projects deployed to meet DTE's Renewable
17 Portfolio Standard ("RPS") obligations not covered by the CCAA; (vi) the revenue
18 requirement of other resources identified in DTE's Integrated Resource Plan ("IRP") as
19 being caused by Google's load; (vii) increased fuel and purchased power costs; (viii)
20 the revenue requirement of the required transmission investments; and (ix) any other
21 incremental expenses or resource revenue requirement that was caused by DTE
22 serving Google's load under the PSA and CCAA.¹⁷

¹⁵ DTE Witness Foley Revised Direct at NTF-19.

¹⁶ DTE Witness Foley Revised Direct at NTF-19 through NTF-20 and Exhibit A-16 at 8 (Section 5.1.3 of PSA).

¹⁷ DTE Response to Data Requests MNSDE-1.2a through MNSDE-1.2d and ABDE-1.3.

1 Finally, the PSA includes credit and collateral requirements satisfied through a
2 Parent Guaranty and, if necessary, based on the parent's credit rating, a Letter of
3 Credit, with the required amount covering a portion of Google's financial obligations
4 under the PSA and declining over the latter portion of the contract term once the
5 forecasted termination payment decreases below the initial required amount of
6 collateral.¹⁸

7 **Q PLEASE PROVIDE A SUMMARY OF THE MAJOR ELEMENTS OF THE CCAA.**

8 A The CCAA establishes obligations between DTE and Google under which DTE would
9 develop up to 480 MW of energy storage projects and 1,600 MW of renewable energy
10 projects whose costs would be recovered from Google in exchange for certain capacity
11 and energy credit payments to Google.¹⁹

12 The CCAA also requires Google to transfer 300 MW of ZRCs from MISO Zone 7
13 to DTE from June 1, 2028 through May 31, 2033 and to pay a financial incentive to
14 DTE for those transferred ZRCs.²⁰ Google would receive a capacity credit payment
15 from DTE for the transferred ZRCs just like it would for the energy storage and
16 renewable energy projects under the CCAA.²¹

17 The renewable energy project portion of the CCAA is essentially designed to
18 act as a VGP program for Google that, if fully implemented, would provide sufficient
19 renewable energy for the Google load to reach 100% renewable energy.²² If the
20 renewable energy project portion of the CCAA is not fully implemented, Google is

¹⁸ DTE Witness Foley Revised Direct at NTF-21 through NTF-23.

¹⁹ Application at 3-4.

²⁰ *Id.*; DTE Response to Data Request CEOMEIBCIEIDE-1.1a; Revised Redacted Exhibit A-18
at 38.

²¹ Application at 3-4.

²² Application at 3-4 and DTE Witness Bilyeu Direct at KLB-9.

1 responsible for any incremental cost incurred by DTE in meeting the renewable
2 portfolio standard to the extent such costs are attributable to Google.²³

3 Google is responsible for the full cost of the energy storage projects and
4 renewable energy projects under the CCAA for their full depreciable life over the
5 20-year term of the CCAA and must pay a termination payment if the CCAA is
6 terminated.²⁴ The CCAA is not renewable at the end of its 20-year term.²⁵ DTE is
7 proposing to establish a regulatory liability to track the amounts paid by Google for the
8 projects over the term of the CCAA that exceed the normal book life revenue
9 requirement of the projects over the term of the CCAA.²⁶

10 Finally, like the PSA, the CCAA includes credit and collateral requirements
11 satisfied through a Parent Guaranty and, if necessary, based on the parent's credit
12 rating, a Letter of Credit, with the required amount covering a portion of Google's
13 financial obligations under the CCAA and declining over the latter portion of the contract
14 term once the forecasted termination payment decreases below the initial required
15 amount of collateral.²⁷

16 **Q PLEASE PROVIDE A SUMMARY OF THE MAJOR ELEMENTS OF THE RIDER 12**
17 **DR AGREEMENT AND THE LEA.**

18 **A** As noted earlier in my testimony herein, while DTE is not requesting approval of them
19 in this proceeding, DTE in its direct testimony identifies two additional agreements
20 between DTE and Google – a Rider 12 DR Agreement and an LEA. As I have noted,
21 DTE relies upon these two additional agreements in its direct testimony to help support

²³ DTE Witness Foley Revised Direct at Exhibit A-18 at 9 (Section 4.1.10.2 of CCAA).

²⁴ DTE Witness Foley Revised Direct at NTF-24 through NTF-31.

²⁵ DTE Response to Data Requests STDE-1.9 and STDE-1.11.

²⁶ DTE Witness Foley at NTF-30.

²⁷ DTE Witness Foley Revised Direct at NTF-40 through NTF-41.

1 its contention that the PSA and CCAA are reasonable, prudent, in the public interest,
2 and will not increase the cost of service to other customers.²⁸

3 The Rider 12 DR Agreement commits Google, pursuant to DTE Rider 12, from
4 June 1, 2028 through May 31, 2033, as a Load Modifying Resource ("LMR") Demand
5 Resource, to reduce its demand at its facility to 650 MW or lower when called upon by
6 MISO to do so during emergencies.²⁹ DTE indicates the Rider 12 Agreement does not
7 need Commission approval because it is a standard tariff offering.³⁰

8 The Rider 12 DR Agreement requires Google to perform such demand
9 reductions whenever MISO declares an emergency, but with the demand reductions
10 occurring no more than [BEGIN CONFIDENTIAL] [REDACTED]

11 [REDACTED]
12 [REDACTED] [END CONFIDENTIAL]³¹ This availability requirement is well in excess of
13 MISO's proposed 2028/2029 Planning Year and beyond minimum required availability
14 for a Type I LMR Demand Resource (only one four hour demand reduction per MISO
15 Season) that, as of the filing date of this testimony, was currently pending before FERC
16 in Docket No. ER25-1886.³² Google would receive the same contract price (or credit)
17 from DTE for its participation in Rider 12 as other Rider 12 customers.³³

18 DTE indicates the contract damages for non-performance under the Rider 12
19 Agreement are structured to ensure that all potential MISO penalties are assessed to
20 Google, which would include those MISO has proposed for LMRs in FERC Docket No.
21 ER26-1882, with DTE also assessing additional damages at two times the contract

²⁸ DTE Witness Foley Revised Direct at NTF-6.

²⁹ *Id.* and DTE Witness Burgdorf Direct at SDB-21 through SDB-23.

³⁰ DTE Response to Data Request STDE-3.12.

³¹ DTE Response to Data Requests CEOMEIBCIEIDE-1.24b and ABDE-1.9e.

³² DTE Witness Burgdorf Direct at SDB-22 through SDB-23 and DTE Response to Data Request ABDE-1.9d.

³³ DTE Response to Data Request STDE-3.14.

1 price for the non-performance amount and assessing any future Planning Year lost
2 accreditation at the lost Auction Clearing Price revenues plus at least the Cost of New
3 Entry.³⁴

4 The LEA requires Google to pay up to \$50 million toward the DTE distribution
5 project necessary to provide service to Google.³⁵ DTE indicates the distribution project,
6 which would directly interconnect the Google data center load to the ITC Transmission
7 (“ITC”) transmission system without connecting to, or utilizing, any other DTE
8 distribution facilities, has an estimated cost of \$29.1 million to \$44.3 million.³⁶ DTE also
9 indicates Google is responsible for costs in excess of \$50 million to the extent they are
10 due to unexpected site conditions or events, including, but not limited to, environmental
11 conditions, below grade obstructions, or permitting/zoning issues.³⁷ DTE indicates that
12 in the event the cost of the distribution project exceeds \$50 million and is not related to
13 an unexpected site condition or event, DTE will propose adding the additional cost to
14 its rate base for recovery in a future rate case consistent with DTE’s rate book.³⁸ This
15 means that DTE intends to propose that customers as a whole, rather than just Google,
16 would pay for any cost overrun not related to an unexpected site condition or event.
17 However, DTE notes that Google is not receiving any Contribution in Aid of
18 Construction (“CIAC”) allowance even though DTE estimates Google would have been
19 eligible for a CIAC allowance of approximately \$550 million under DTE’s current
20 Commission-approved CIAC policy.³⁹ Also, it should also be noted that the total
21 distribution costs incurred to serve the Google data center load would be considered in

³⁴ DTE Witness Burgdorf Direct at SDB-23 through SDB-24.

³⁵ DTE Witness Foley Revised Direct at NTF-6.

³⁶ DTE Witness Benyard Direct at SNB-6 and DTE Response to Data Requests ABDE 1.1a through ABDE-1.1c.

³⁷ *Id.*

³⁸ DTE Witness Benyard Direct at SNB-6 through SNB-7.

³⁹ DTE Witness Benyard Direct at SNB-7.

1 the PSA's Affordability Backstop regardless of whether the cost is directly recovered
2 from Google or recovered from customers as whole.

3 **Q ARE ANY TRANSMISSION UPGRADES NECESSARY TO PROVIDE ELECTRIC**
4 **SERVICE TO GOOGLE AND, IF SO, WHO WILL PAY FOR THEM?**

5 A Yes. DTE indicates ITC has identified transmission upgrades with a total estimated
6 cost of \$308 million to provide electric service to the Google data center load.⁴⁰ The
7 revenue requirement for these transmission upgrades would be recovered by ITC
8 through its FERC-jurisdictional transmission service rates under the MISO Tariff.⁴¹ As
9 a result, DTE's full-service and retail open access customers as a whole would bear
10 the vast majority of this cost, since the ITC transmission zone principally consists of the
11 DTE service territory. DTE full-service customers would see the cost through base
12 rates and DTE's PSCR factor. DTE retail open access customers would see the cost
13 through the passthrough of MISO Tariff transmission charges by their Alternative
14 Electric Supplier ("AES"). This said, DTE estimates that if the Google data center load
15 fully materializes, the additional billing units provided by Google would more than
16 counteract the increased costs, such that the projected effective ITC transmission rate
17 or, more properly, DTE transmission expenses in 2029, would decrease from
18 \$0.0148/kWh to \$0.0144/kWh.⁴² Also, critically, any increase in transmission expenses
19 for DTE would be considered in the PSA's Affordability Backstop.

⁴⁰ DTE Witness Benyard Direct at SNB-5.

⁴¹ DTE Witness Burgdorf at Direct SDB-20 through SDB-21.

⁴² *Id.*

III. DTE'S NET BENEFIT ANALYSIS

Q IN ADDITION TO IDENTIFYING THE DISTRIBUTION AND TRANSMISSION FACILITIES, HAS DTE AT LEAST PRELIMINARILY IDENTIFIED THE RESOURCES IT WOULD NEED TO ADD TO ITS SYSTEM TO SERVE THE GOOGLE DATA CENTER LOAD?

A Yes, this is addressed in the direct testimony of DTE Witnesses Burgdorf and Brooks. While DTE's actual plan will be developed as part of its 2026 Integrated Resource Plan ("IRP") filing, for a 20-year study period ending in 2047 DTE developed a Customer Datacenter Case which added Google's load, the energy storage and renewable energy resources that Google will pay under the CCAA, Google's 300 MW ZRC transfer to DTE through May 31, 2033, and Google's Rider DR Agreement participation through May 31, 2033 to a Base Case that includes the Oracle data center load, the Oracle incremental renewable generation additions, and the energy storage resources that Oracle will be paying for under its Energy Storage Agreement with DTE approved on an *ex parte* basis in U-21990.⁴³ In addition, since the Google CCAA energy storage and renewable energy resources effectively move up the projected in-service date of approximately 500 MW of 4-hour energy storage and 250 MW of renewable energy resources, DTE removed these additions in the Base Case from the Customer Datacenter Case during the period of 2033 through 2036.⁴⁴ It should also be noted that while Monroe Units 1 through 4 were modeled with retirements consistent with DTE's last Commission-approved IRP, Monroe Units 1 and 2 were operated beyond 2032 in both the Base Case and the Customer Datacenter Case as a proxy for the new

⁴³ DTE Witness Burgdorf Direct at SDB-6 through SDB-12.

⁴⁴ DTE Witness Burgdorf Direct at SDB-11 through SDB-12.

resources that will be necessary to replace Monroe Units 1 and 2 when they retire in 2032.⁴⁵

While DTE used projected MISO Direct Loss of Load (“DLOL”) capacity accreditation in developing the Base Case and Customer Datacenter Case to add enough projected accredited capacity (i.e., projected ZRCs) to meet DTE’s projected MISO Planning Reserve Margin Requirement (“PRMR”), DTE also had PowerGEM perform a SERVVM loss of load probability analysis of the Customer Datacenter Case for both 2029 and 2033 with a focus in MISO Zone 7.⁴⁶ 2029 was selected because it is the projected first year of full ramp for the Google data center load and 2033 was selected because it is the first year without the 300 MW ZRC transfer from Google to DTE and without Google participation in DTE Rider 12.⁴⁷ The SERVVM analysis showed a 2029 Loss of Load Expectation (“LOLE”) for the Customer Datacenter Case that was very close to the industry target of no more than one firm load shedding event day in ten years (or 0.1 event-days per year).⁴⁸ However, the SERVVM analysis showed a problematic 2033 LOLE of one firm load shedding event day in 4.2 years (or 0.238 event-days per year).⁴⁹ Further analysis showed 677 MW of “perfect capacity” would need to be added to the Customer Datacenter Case by 2033 in order to bring the LOLE down to no more than 0.1 event-days per year.⁵⁰ To address this need, DTE added to the Customer Datacenter Case a 727 MW Combined Cycle Combustion Turbine (“CCCT”) generation facility with Carbon Capture and Sequestration (“CCS”) as a proxy for a resource addition that will ultimately be identified in DTE’s 2026 IRP.⁵¹

⁴⁵ DTE Witness Burgdorf Direct at SDB-9.

⁴⁶ DTE Witness Burgdorf Direct at SDB-8 and SDB-10 and DTE Witness Brooks at JJWB-8.

⁴⁷ DTE Witness Burgdorf Direct at SDB-10.

⁴⁸ DTE Witness Brooks at JJWB-8.

⁴⁹ DTE Witness Brooks at JJWB-8.

⁵⁰ *Id.*

⁵¹ DTE Witness Burgdorf Direct at SDB-10 through SDB-13.

DTE's follow up SERVIM analysis of this revised Customer Datacenter Case showed a 2033 LOLE of 0.093 event-days per year.⁵²

Q WOULD THE COST OF THE ADDITIONAL RESOURCE(S) NECESSARY IN THE CUSTOMER DATACENTER CASE IN 2033 BE DIRECTLY ASSIGNED TO GOOGLE OR RECOVERED FROM ALL CUSTOMERS?

A The resource(s) would not be part of the CCAA. As a result, DTE's assumption is the cost of the resource(s) would be recovered from all of DTE's full-service customers, not just Google.

Q BASED ON COMPARING THE CUSTOMER DATACENTER CASE TO THE BASE CASE AS WELL AS FACTORING IN THE PREVIOUSLY ESTIMATED DISTRIBUTION AND TRANSMISSION COSTS, DID DTE PERFORM AN ANALYSIS OF THE PROJECTED AGGREGATE BENEFITS FROM SERVING THE GOOGLE DATA CENTER LOAD VERSUS THE PROJECTED AGGREGATE COSTS OF SERVING THE GOOGLE DATA CENTER LOAD?

A Yes. DTE Witnesses Burgdorf and Willis together sponsor and present such an analysis for a 20-year study period beginning in 2028 that corresponds to the expected 20-year term of the CCAA and expected initial 20-year term of the PSA. It is summarized in DTE Witness Willis' Exhibit A-19.

For Exhibit A-19, DTE Witness Burgdorf performed an analysis to project the difference between the two cases with respect to PSCR costs, Other Non-Fuel O&M Expenses, the CCGT with CCS revenue requirement, and the estimated benefit of pulling storage in-service dates ahead, while DTE Witness Willis performed the

⁵² DTE Witness Brooks at JJWB-9 through JJWB-10.

1 analysis of what DTE calls the “Base Sales Benefit”. As can be seen in Exhibit A-19,
2 DTE calculates a total net benefit from serving the Google data center load of \$1.70
3 billion for 2028 through 2047 in nominal dollars. This consists of a projected Base
4 Sales Benefit of \$4.85 billion, a PSCR benefit of \$2.31 billion, an Other Non-Fuel O&M
5 cost of \$0.02 billion, a Proxy CCCT cost of \$4.17 billion, a CCS cost of \$2.43 billion,
6 and an energy storage pull ahead benefit of \$1.16 billion.⁵³

7 **Q HOW DID DTE CALCULATE THE \$4.85 BILLION BASE SALES BENEFIT IN**
8 **NOMINAL DOLLARS?**

9 A In Exhibit A-20, DTE conducted the Base Sales Benefit calculation by first modifying
10 DTE’s standard cost of service model as approved in Case U-21534 (DTE’s 2025 rate
11 case) to add in the incremental revenues and incremental base power supply expenses
12 associated with serving Google, assuming the Google load is at its full ramp of 1,000
13 MW with a 90% load factor. This resulted in an estimated \$201.529 million revenue
14 sufficiency (base sales net benefit) in 2025, which was then used to produce numbers
15 for 2029 through 2047 assuming the \$201.529 million value grows by 1.5% per year.⁵⁴
16 For 2028, the 2025 number was also assumed to grow by 1.5% per year, but then
17 reduced to 43% of its initial value to roughly estimate the impact of the Google data
18 center load not being fully ramped in that year.⁵⁵ To these amounts for 2028 through
19 2047, DTE added an estimated nuclear surcharge benefit of 5.049 million per year
20 (\$2.171 million 2028 (43% of \$5.049 million)) to get final Base Sales Benefit values for
21 2028 through 2047.⁵⁶

⁵³ DTE Witness Willis Direct at AW-7.

⁵⁴ Exhibit A-20; Willis Workpaper U-22058 Exhibit A-10 Base Sales Benefit.xlsx; DET Witness Willis Direct at AW-10; DTE Response to Data Requests MNSDE-3.4 through MNSDE-3.5b.

⁵⁵ *Id.*

⁵⁶ *Id.*

Q HOW DO YOU RESPOND TO DTE'S NET BENEFIT ANALYSIS?

A The analysis demonstrates there is a potential for significant net benefit to be provided to DTE's other customers if the Google data center load fully materializes at its expected ramp rate and remains fully materialized for the balance of the 20-year study period. However, DTE has not performed any analysis of a delayed ramp, a failure for the Google data center load to fully materialize, or a failure of the Google data center load to remain fully materialized.⁵⁷

In addition, DTE's analysis in Exhibit A-19 does not reflect the impact of the CCCT with CCS only being 15 years into its estimated 35-year book life when the assumed initial term of the PSA expires at the end of 2047.⁵⁸ If Google ceases to be a DTE customer at that time, DTE's other customers will be left with undepreciated remaining net book value of the facility (offset by any market value or avoided costs that can be derived from it). While DTE did perform a side analysis, which was presented in DTE Witness Burgdorf's Exhibit A-15 and estimated \$75.01 million net benefit on a present value basis for the period of 2048 through 2067, that analysis simply assumed capacity and energy prices annually grow at a rate of 3.0% per year from the level they were at in 2038. If 0% growth is instead assumed, I have calculated the Exhibit A-15 projected net present value *benefit* of \$75.01 million to DTE's other customers for the CCCT with CCS for 2048 through 2067 would become a projected net present value *cost* of \$129.55 million. I have provided this calculation in Exhibit AB-2.

It should also be noted that DTE presented its Exhibit A-19 results in nominal dollars rather than on a present value basis more typically used for IRP analysis and which DTE itself used in Exhibit A-15. I have calculated that, on a net present values

⁵⁷ DTE Response to Data Request ABDE-1.12.

⁵⁸ DTE Witness Burgdorf Direct at SDB-14; 15 years = 2048 - 2033

basis with a discount rate of 7.05%, DTE's net benefit value drops from approximately \$1.7 billion to approximately \$1.0 billion when presented on a present value basis.⁵⁹

Finally, the net benefit analysis results are a function of the underlying assumptions used therein, and DTE conducted no sensitivity analysis to test how its results could vary depending on how those assumptions are adjusted.

For all the above reasons, DTE's net benefit projection is not sufficient to show DTE's other customers would not ultimately see higher costs from DTE serving Google pursuant to the PSA and CCAA. Without additional protections (e.g., DTE's proposed Affordability Backstop supplemented by the other additional protections I will discuss later in this testimony), the PSA and CCAA would require DTE's other customers to take on the risk of the projected net benefit instead materializing as a net cost, while DTE earns a return on its investments to serve Google regardless of whether DTE's other customers see a net benefit or a net cost.

IV. INSUFFICIENCY OF AFFORDABILITY BACKSTOP

Q EARLIER IN YOUR TESTIMONY YOU DISCUSSED THE PROPOSED AFFORDABILITY BACKSTOP DTE HAS INCLUDED IN THE PSA WITH GOOGLE. PLEASE EXPLAIN WHETHER IT WOULD ADDRESS ENSURING DTE'S EXISTING CUSTOMERS DO NOT SEE HIGHER COSTS AS A RESULT OF DTE SERVING GOOGLE UNDER THE PSA AND CCAA.

A The proposed Affordability Backstop (Section 5.1.3 of the PSA) is helpful toward addressing this issue because it does not rely on a snapshot in time. As such it helps to eliminate the risk otherwise placed on other DTE customers with respect to DTE's projections not being realized sufficiently to ensure DTE's other customers do not

⁵⁹ ABATE Workpaper JRD-WP-1.

1 ultimately see higher costs from DTE serving Google. It does so by essentially
2 providing a regular checkup during regulatory proceedings of the aggregate revenues
3 from Google versus aggregate costs incurred to serve Google. However, putting aside
4 a collateral sufficiency issue, which I will discuss later in my testimony since that issue
5 affects both the PSA and the CCAA, I have identified a shortcoming in the Affordability
6 Backstop as filed that makes it insufficient to protect DTE's other customers with
7 respect to termination of the PSA.

8 **Q PLEASE EXPLAIN YOUR CONCERN WITH RESPECT TO THE AFFORDABILITY**
9 **BACKSTOP AND TERMINATION OF THE PSA.**

10 A The Affordability Backstop as filed appears to not extend beyond termination of the
11 PSA and does not provide for modification of the termination payment under the PSA
12 in the event the Commission finds the aggregate costs of serving Google exceed the
13 aggregate benefits from serving Google as a result of termination.

14 **Q DID YOU EXPLORE THIS ISSUE WITH DTE IN DISCOVERY?**

15 A Yes, I did so in Data Request ABDE-1.13. In that data request, I asked DTE to explain
16 in detail whether, in the case of termination of the PSA, the Commission under the
17 Affordability Backstop would have the ability to modify the termination payment paid by
18 Google if the Commission determined that, under the termination of the PSA, the
19 aggregated cost of providing service to Google exceeded the aggregated benefits of
20 serving Google. DTE's answer included an objection, but nevertheless in part stated,
21 "Subject to and without waiving this objection, once the PSA is terminated it cannot be
22 modified."⁶⁰

⁶⁰ DTE Response to Data Request ABDE-1.13.

1 **Q WHAT IS YOUR RECOMMENDATION TO THE COMMISSION WITH RESPECT TO**
2 **RESOLVING THIS ISSUE?**

3 A To the extent the Commission grants approval of the PSA and CCAA, that approval
4 should be made conditional on DTE and Google modifying the Affordability Backstop
5 (Section 5.1.3 of the PSA) to allow an evaluation and modification of the termination
6 payment by the Commission based on the facts and circumstances known or knowable
7 at the time of termination of the PSA to ensure the costs incurred to serve Google do
8 not exceed the benefits from serving Google due to the termination, giving full
9 consideration to the reasonably projected forward looking benefits at that time from any
10 sunk costs incurred by DTE to serve Google.

11 **V. INSUFFICIENT PROTECTION**
12 **FROM COLLATERAL SHORTFALLS**

13 **Q YOU HAVE INDICATED YOU HAVE ANOTHER CONCERN WITH RESPECT TO**
14 **COLLATERAL UNDER BOTH THE PSA AND CCAA. PLEASE EXPLAIN THE**
15 **CONCERN.**

16 A The Affordability Backstop of the PSA and the termination payments under both the
17 PSA and CCAA are only as good as DTE's ability to collect from Google payments and
18 calls on Google's collateral. If the combination of the two is insufficient to cover what
19 Google owes, it could potentially leave DTE's other customers with Google's unpaid
20 costs. Given the multibillion dollar level of termination payments under the PSA and
21 CCAA, this is an unacceptable level of risk for DTE's other customers.⁶¹ Furthermore,
22 given DTE will be the party managing the form and level of collateral for Google for the

⁶¹ DTE Witness Foley Revised Direct at NTF-18.

1 PSA and CCAA, DTE is the party that should be at risk if Google's collateral proves
2 insufficient, not DTE's other customers.

3 **Q IN ITS DECEMBER 19, 2025 ORDER IN CASE NO. U-21990, THE COMMISSION**
4 **INDICATED THAT ALL RISK UNDER THE SPECIAL CONTRACTS FOR THE**
5 **ORACLE DATA CENTER LOAD ASSOCIATED WITH THE SUFFICIENCY OF**
6 **COLLATERAL SHALL BE BORNE BY DTE.⁶² HAS DTE SHOWN ANY**
7 **WILLINGNESS TO MAKE SUCH A COMMITMENT TO ACCEPT SUCH RISK WITH**
8 **RESPECT TO THE PSA AND CCAA FOR GOOGLE IN THIS CURRENT**
9 **PROCEEDING?**

10 **A** No. In response to a data request from the Commission Staff ("Staff") to DTE, DTE
11 indicated it had not made such a commitment in its application or testimony.⁶³ DTE
12 also indicated that in the highly unlikely event of a bankruptcy or other circumstance in
13 which recovery from Google, its parent guarantor, and letters of credit is not sufficient,
14 DTE would not seek to recover from customers costs that are ultimately determined by
15 the Commission, pursuant to Section 5.1.3 of the PSA, to be in excess of the combined
16 revenues payable to the Company under the PSA and related agreements.⁶⁴ While
17 DTE's position is appreciated, it is not the same as a commitment from DTE in this
18 respect. A commitment is necessary.

⁶² Case No. U-21990, December 18, 2025 Order at 41.

⁶³ DTE Response to Data Request STDE-8.2.

⁶⁴ *Id.*

1 **Q WHAT IS YOUR RECOMMENDATION TO THE COMMISSION WITH RESPECT TO**
2 **RESOLVING THIS ISSUE.**

3 A To the extent the Commission grants approval of the PSA and CCAA, that approval
4 should be made conditional on DTE agreeing that in the event of a failure by Google to
5 pay any amount due to DTE under the PSA or CCAA, or in the event of a termination,
6 default, or other event whereby DTE is required to draw on the letters of credit or
7 parental guaranties under the PSA or CCAA, if DTE determines that the specified
8 collateral is not sufficient to cover the full amount of the remaining financial exposure
9 associated with the PSA or CCAA (minus the value to customers), any unrecovered
10 costs shall not be borne by ratepayers and DTE shall bear responsibility for any
11 remaining liability. This condition would be comparable to what the Commission
12 imposed on DTE for the Oracle data center load special contracts on page 41 of the
13 Commission's December 18, 2025 Order in Case No. U-21990.

14 **VI. COMMITMENT TO MAINTAIN RESOURCE ADEQUACY**

15 **Q WHAT STEPS HAS DTE TAKEN TO ENSURE PROVIDING ELECTRIC SERVICE TO**
16 **GOOGLE UNDER THE PSA AND CCAA WILL NOT COMPROMISE THE**
17 **PROVISION OF RESOURCE ADEQUACY TO DTE'S OTHER CUSTOMERS.**

18 A DTE has taken two steps. First, through Section 2 of the PSA, DTE has the right to
19 exercise reasonable discretion to limit Google's capacity ramp if the electricity capacity
20 achieved at any time through project agreements to meet that ramp.is insufficient to
21 meet that ramp.⁶⁵ DTE indicated in its direct testimony that any of the following could
22 trigger the provision: (i) the CCAA or Rider DR Agreement is terminated; (ii) DTE is
23 unable to achieve or maintain Google's load ramp or max load due to reasons not

⁶⁵ DTE Witness Foley revised Direct at Exhibit A-16 at 2 (Section 2.1).

1 attributable to DTE; (iii) DTE is unable to achieve or maintain Google's load ramp or
2 max load due to Google's underperformance or nonperformance under any agreement
3 with DTE; and/or (iv) DTE determines that the energy storage portfolio being deployed
4 under the CCAA is not feasible.

5 Second, in Case No. U-22059, DTE has filed proposed revisions to DTE's
6 existing Electric Procedures, Section C3 of its Rate Book, requiring customers with a
7 capacity at least 500 MW be subject to firm load shedding prior to other customers,
8 provided that such customer load shedding does not compromise system reliability and
9 can prevent shedding firm load of other DTE Electric Customers.⁶⁶

10 **Q WHAT CONCERNS DO YOU HAVE WITH THESE STEPS?**

11 A First, with respect to Section 2 of the PSA, while the provision gives DTE the
12 reasonable *discretion* to limit Google's load ramp or max load when the triggers apply,
13 there is no obligation on DTE to fully utilize that provision to protect resource adequacy
14 for DTE's other customers.

15 Second, DTE's application in U-22059 was made to be in compliance in the
16 Commission's December 18, 2025 order in U-21990 regarding the Oracle data center
17 load special contracts. As such, DTE's proposal should have only been filed to apply
18 to Oracle and there is a real possibility that the Commission will reject DTE's application
19 in that proceeding, especially since DTE in its application proposed to also generically
20 apply the provision to all new Rate D11 loads 100 MW or larger, which is highly
21 problematic for the reasons explained in the comments of ABATE that were filed in that
22 proceeding on May 19, 2026. This said, the 1,000 MW size of the Google data center
23 load addition in combination with the size of the resource additions necessary to

⁶⁶ Case No. U-22059, DTE March 18, 2026 Application at Attachment A; DTE Response to Data Requests CEOMEIBCIIDE-1.39a and CEOMEIBCIIDE-1.39b.

1 support it, justify subjecting Google to an early load shedding requirement until the
2 resources necessary to serve it are fully online.

3 Finally, neither of the two steps DTE has taken are adequate to deal with the
4 resource adequacy cliff that will be created on May 31, 2033 when the 300 MW ZRC
5 transfer by Google to DTE under the CCAA ceases and the approximately 250 MW of
6 ZRCs Google is providing under the Rider 12 DR Agreement will cease to be provided.
7 This approximately 550 MW loss of ZRCs is likely the principal contributor to DTE's
8 projected need for 677 MW of "perfect capacity" in 2033. Since the 677 MW of "perfect
9 capacity" is not associated with the CCAA or any agreement between DTE and Google,
10 it does not appear Section 2 of the PSA will provide any protection for this situation for
11 DTE's other customers. Furthermore, an early load shedding requirement is not going
12 to provide enough protection on its own.

13 **Q GIVEN YOUR ABOVE CONCERNS, WHAT DO YOU RECOMMEND TO THE**
14 **COMMISSION IN THIS PROCEEDING WITH RESPECT TO RESOURCE**
15 **ADEQUACY?**

16 **A** To the extent the Commission grants approval of the PSA and CCAA, that approval
17 should be made conditional on:

- 18 • DTE committing to fully utilize the discretion given to it under Section 2 of
19 the PSA to limit the load ramp and maximum demand of Google as
20 necessary to ensure resource adequacy for DTE's other customers.
- 21 • DTE modifying its emergency procedures to subject Google to firm load
22 shedding prior to other customers, provided that such customer load
23 shedding does not: (i) compromise system reliability; and (ii) can prevent
24 shedding firm load of other DTE Electric Customers, until such time all of
25 the resources necessary to serve the Google data center load are in service.
- 26 • Modification of the CCAA and the Rider 12 DR Agreement such that: (i)
27 Google is required beyond May 31, 2033 to continue to transfer 300 MW of
28 ZRCs to DTE; and (ii) the Google' facility is required beyond May 31, 2033
29 to continue to be curtailable down to a demand of 650 MW, to the extent

DTE has been unable to bring 550 MW of ZRCs of new capacity online in MISO Zone 7 to replace the ZRCs that were being provided by Google.

VII. INTRA-CLASS COST SUBSIDIES

Q PLEASE EXPLAIN YOUR CONCERN WITH RESPECT TO DTE'S PROPOSAL TO PLACE THE GOOGLE DATA CENTER LOAD INTO THE D11 CUSTOMER CLASS.

A As I noted earlier in my testimony, DTE's current full-service load in the D11 customer class totals to approximately 1.8 GW with a 73.4% system average load factor spread over 2,079 customers.⁶⁷ In contrast, Google, if its load fully materializes, would as a single customer have a demand of approximately 1.0 GW with an expected load factor of approximately 90%.⁶⁸ Assuming the Oracle data center also has a load factor of approximately 90% and there is no load growth in traditional D11 full-service customers, Oracle and Google together would make up approximately 57% of the total full-service demand and approximately 62% of the total full-service energy in the D11 rate class.⁶⁹ Google alone would account for approximately 24% of the total full-service demand and 26% of the total full-service energy in the D11 rate class.⁷⁰ As a result, placing Google (and Oracle) into the D11 customer class will overwhelm the current load characteristics of the traditional commercial and industrial customers of the D11 customer class. This is highly likely to cause large subsidies between the members of the class given rate design does not necessarily fully align with cost allocation in class

⁶⁷ DTE Response to ABDE-1.4, U-22058 ABDE-1.4 U-21534 Approved Rate Design Model.xlsx at D11 Total Tab, Line 1, 9 and 30; $1.8 \text{ GW} \approx 1.788 \text{ GW} = 21,460,521 \text{ kW} / 1,000,000 \text{ kW per GW} / 12 \text{ months per year}$; $73.4\% \text{ load factor} = 11,505,383 \text{ MWh} / [(21,460,521 \text{ kW} / 1,000 \text{ kW per MW} / 12 \text{ months per year}) \times 8,760 \text{ hours per year}]$. (Exhibit AB-1 at .).

⁶⁸ Application at 2 and DTE Witness Bilyeu Direct at KLB-11; $90\% \approx 89.95\% = 7.88 \text{ TWh} / [(1.0 \text{ GW} / 1,000 \text{ GW per TW}) \times 8,760 \text{ hours}]$.

⁶⁹ $57\% \approx 57.14\% = (1.4 \text{ GW} + 1.0 \text{ GW}) / (1.8 \text{ GW} + 1.4 \text{ GW} + 1.0 \text{ GW})$; $61\% \approx 62.05\% = [(1.4 \text{ GW} + 1.0 \text{ GW}) \times 90\%] / [1.8 \text{ GW} \times 73.4\% + (1.4 \text{ GW} + 1.0 \text{ GW}) \times 90\%]$.

⁷⁰ $24\% \approx 23.81\% = (1.0 \text{ GW}) / (1.8 \text{ GW} + 1.4 \text{ GW} + 1.0 \text{ GW})$; $26\% \approx 25.85\% = (1.0 \text{ GW} \times 90\%) / [1.8 \text{ GW} \times 73.4\% + (1.4 \text{ GW} + 1.0 \text{ GW}) \times 90\%]$.

1 cost of service studies. For example, production plant is allocated to customer classes
2 in cost of service studies on a 75% 4-CP demand and 25% annual energy consumption
3 basis, while in the rate design for D11 the production plant allocated to the D11 rate
4 class is allocated to the customers in the class based on each customer's monthly peak
5 demand (not customer 4-CP demand) and energy consumption, and not necessarily
6 on a 75% demand and 25% energy basis. Furthermore, there is significant possibility
7 that at some point certain costs may be directly allocated to the customer class the
8 large data center loads are within. This would potentially inappropriately assign a
9 portion of these costs to traditional commercial and industrial customers served at
10 primary or higher voltage. Finally, all of this is unnecessary. A new rate class can be
11 readily established for Google and the other large data center loads that initially utilizes
12 the same rates as the Rate D11 class. This would produce the same outcome as
13 initially placing these loads on Rate D11 at the outset of service without introducing any
14 risk of intra-class subsidies to the existing members of the Rate D11 class.

15 **Q WHAT IS YOUR RECOMMENDATION TO THE COMMISSION WITH RESPECT TO**
16 **THIS ISSUE?**

17 **A** To the extent the Commission grants approval of the PSA and CCAA, that approval
18 should be conditional on modification of the proposed PSA to place Google into its own
19 customer class, potentially with other large data center loads, but separate and apart
20 from the Rate D11 class. The initial rates for this separate class would be the same as
21 those for Rate D11, subject to modification as necessary after these loads begin taking
22 service.

VIII. FINANCIAL INCENTIVE FOR ZRC TRANSFER

Q PLEASE EXPLAIN YOUR CONCERN WITH RESPECT TO DTE'S PROPOSAL TO EARN A FINANCIAL INCENTIVE ON THE 300 MW ZRC TRANSFER FROM GOOGLE TO DTE UNDER THE CCAA.

A The ZRC Transfer is not a PPA, it is a self-supply of capacity by Google. DTE should not be permitted to extract monopoly rents from its captive customers who self-supply capacity and energy. Furthermore, even if Google is freely willing to provide the financial incentive to DTE, it should not be treated as a cost DTE's other customers might be responsible for in some part, but rather additional revenue being contributed by Google toward covering the total cost to serve it.

Q WHAT DO YOU RECOMMEND TO THE COMMISSION ON THIS ISSUE?

A To the extent the Commission grants approval of the PSA and CCAA, that approval should be conditional on DTE withdrawing its proposal to earn a financial incentive on the ZRC transfer by Google to DTE under the CCAA or, in the alternative, DTE agreeing that the Commission's approval of Google's agreement to provide a financial incentive to DTE for the ZRC transfer does not set any precedent with respect to whether DTE is entitled to mandate the receipt of such a financial incentive from its customers on customer self-supplied capacity and energy.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

1 **Qualifications of James R. Dauphinais**

2 **Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

3 A James R. Dauphinais. My business address is 16690 Swingley Ridge Road, Suite 140,
4 Chesterfield, MO 63017, USA.

5 **Q PLEASE STATE YOUR OCCUPATION.**

6 A I am a consultant in the field of public utility regulation and a Managing Principal with
7 the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory
8 consultants.

9 **Q PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.**

10 A I graduated from Hartford State Technical College in 1983 with an Associate's Degree
11 in Electrical Engineering Technology. Subsequent to graduation, I was employed by
12 the Transmission Planning Department of the Northeast Utilities Service Company¹ as
13 an Engineering Technician.

14 While employed as an Engineering Technician, I completed undergraduate
15 studies at the University of Hartford. I graduated in 1990 with a Bachelor's Degree in
16 Electrical Engineering. Subsequent to graduation, I was promoted to the position of
17 Associate Engineer. Between 1993 and 1994, I completed graduate level courses in
18 the study of power system analysis, power system transients and power system
19 protection through the Engineering Outreach Program of the University of Idaho. By
20 1996 I had been promoted to the position of Senior Engineer.

¹In 2015, Northeast Utilities changed its name to Eversource Energy.

1 In the employment of the Northeast Utilities Service Company, I was
2 responsible for conducting thermal, voltage and stability analyses of the Northeast
3 Utilities' transmission system to support planning and operating decisions. This
4 involved the use of load flow, power system stability and production cost computer
5 simulations. It also involved examination of potential solutions to operational and
6 planning problems including, but not limited to, transmission line solutions and the
7 routes that might be utilized by such transmission line solutions. Among the most
8 notable achievements I had in this area include the solution of a transient stability
9 problem near Millstone Nuclear Power Station, and the solution of a small signal (or
10 dynamic) stability problem near Seabrook Nuclear Power Station. In 1993 I was
11 awarded the Chairman's Award, Northeast Utilities' highest employee award, for my
12 work involving stability analysis in the vicinity of Millstone Nuclear Power Station.

13 From 1990 to 1996, I represented Northeast Utilities on the New England Power
14 Pool Stability Task Force. I also represented Northeast Utilities on several other
15 technical working groups within the New England Power Pool ("NEPOOL") and the
16 Northeast Power Coordinating Council ("NPCC"), including the 1992-1996 New York-
17 New England Transmission Working Group, the Southeastern Massachusetts/Rhode
18 Island Transmission Working Group, the NPCC CPSS-2 Working Group on Extreme
19 Disturbances and the NPCC SS-38 Working Group on Interarea Dynamic Analysis.
20 This latter working group also included participation from a number of ECAR, PJM and
21 VACAR utilities.

22 From 1990 to 1995, I also acted as an internal consultant to the
23 Nuclear Electrical Engineering Department of Northeast Utilities. This included
24 interactions with the electrical engineering personnel of the Connecticut Yankee,

1 Millstone and Seabrook nuclear generation stations and inspectors from the Nuclear
2 Regulatory Commission ("NRC").

3 In addition to my technical responsibilities, from 1995 to 1997, I was also
4 responsible for oversight of the day-to-day administration of Northeast Utilities' Open
5 Access Transmission Tariff. This included the creation of Northeast Utilities' pre-FERC
6 Order No. 889 transmission electronic bulletin board and the coordination of Northeast
7 Utilities' transmission tariff filings prior to and after the issuance of Federal Energy
8 Regulatory Commission ("FERC" or "Commission") FERC Order No. 888. I was also
9 responsible for spearheading the implementation of Northeast Utilities' Open Access
10 Same-Time Information System and Northeast Utilities' Standard of Conduct under
11 FERC Order No. 889. During this time, I represented Northeast Utilities on the Federal
12 Energy Regulatory Commission's "What" Working Group on Real-Time Information
13 Networks. Later I served as Vice Chairman of the NEPOOL OASIS Working Group
14 and Co-Chair of the Joint Transmission Services Information Network Functional
15 Process Committee. I also served for a brief time on the Electric Power Research
16 Institute facilitated "How" Working Group on OASIS and the North American Electric
17 Reliability Council facilitated Commercial Practices Working Group.

18 In 1997 I joined the firm of Brubaker & Associates, Inc. The firm includes
19 consultants with backgrounds in accounting, engineering, economics, mathematics,
20 computer science and business. Since my employment with the firm, I have filed or
21 presented testimony before the Federal Energy Regulatory Commission in Consumers
22 Energy Company, Docket No. OA96-77-000; Midwest Independent Transmission
23 System Operator, Inc., Docket No. ER98-1438-000; Montana Power Company, Docket
24 No. ER98-2382-000; Inquiry Concerning the Commission's Policy on Independent
25 System Operators, Docket No. PL98-5-003; SkyGen Energy LLC v. Southern

1 Company Services, Inc., Docket No. EL00-77-000; Alliance Companies, et al., Docket
2 No. EL02-65-000, et al.; Entergy Services, Inc., Docket No. ER01-2201-000;
3 Remediating Undue Discrimination through Open Access Transmission Service,
4 Standard Electricity Market Design, Docket No. RM01-12-000; Midwest Independent
5 Transmission System Operator, Inc., Docket No. ER10-1791-000; NorthWestern
6 Corporation, Docket No. ER10-1138-001, et al.; Illinois Industrial Energy Consumers
7 v. Midcontinent Independent System Operator, Inc., Docket No. EL15-82-000;
8 Midcontinent Independent System Operator, Inc., Docket No. ER16-833-000;
9 Midcontinent Independent System Operator, Inc., Docket No. ER17-284-000;
10 Midcontinent Independent System Operator, Inc. and Ameren Services Company
11 Docket No. ER18-463-000; and PJM Interconnection, L.L.C., Docket No. ER26-1479-
12 000. I have also filed or presented testimony before the Alberta Utilities Commission,
13 the California Public Utilities Commission, the Colorado Public Utilities Commission,
14 the Connecticut Department of Public Utility Control, the Florida Public Service
15 Commission, the Idaho Public Service Commission, the Illinois Commerce
16 Commission, the Indiana Utility Regulatory Commission, the Iowa Utilities Board, the
17 Kentucky Public Service Commission, the Louisiana Public Service Commission, the
18 Michigan Public Service Commission, the Missouri Public Service Commission, the
19 Montana Public Service Commission, the Nevada Public Utilities Commission, the New
20 Mexico Public Regulation Commission, the Council of the City of New Orleans, the New
21 York Public Service Commission, the Oklahoma Corporation Commission, the Public
22 Utility Commission of Texas, the Public Service Commission of Utah, the Virginia State
23 Corporation Commission, the Wisconsin Public Service Commission, the Wyoming
24 Public Service Commission, Federal District Court and various committees of the
25 Illinois, Missouri and South Carolina state legislatures. This testimony has been given

1 regarding a wide variety of issues including, but not limited to, ancillary service rates,
2 avoided cost calculations, certification of public convenience and necessity, class cost
3 of service, cost allocation, fuel adjustment clauses, fuel costs, generation
4 interconnection, interruptible rates, market power, market structure, off-system sales,
5 prudence, purchased power costs, resource adequacy, resource planning, rate design,
6 retail open access, standby rates, transmission losses, transmission planning,
7 transmission rates and transmission line routing.

8 I have also participated on behalf of clients in the Southwest Power Pool
9 Congestion Management System Working Group, the Alliance Market Development
10 Advisory Group and several committees and working groups of the Midcontinent
11 Independent System Operator, Inc. ("MISO"), including the Congestion Management
12 Working Group; Economic Planning Users Group; Loss of Load Expectation Working
13 Group; Market Subcommittee; Michigan Transmission Studies Task Force; Planning
14 Subcommittee; Regional Expansion, Criteria and Benefits Working Group; Resource
15 Adequacy Subcommittee (formerly the Supply Adequacy Working Group); and
16 Reliability Subcommittee. I am currently a member of the MISO Advisory Committee
17 in the end-use customer sector on behalf of industrial customer groups in Illinois,
18 Louisiana, Michigan and Texas. I am also the past Chairman of the Issues/Solutions
19 Subgroup of the MISO Revenue Sufficiency Guarantee ("RSG") Task Force.

20 In 2009, I completed the University of Wisconsin-Madison High Voltage Direct
21 Current ("HVDC") Transmission course for Planners that was sponsored by MISO. I
22 am a member of the Power and Energy Society ("PES") of the Institute of Electrical and
23 Electronics Engineers ("IEEE").

1 MR. CAMPBELL: Thank you, your Honor.
2 That's all for ABATE.

3 JUDGE STALEY: Thank you very much,
4 Mr. Campbell. All right. And then I will move on to
5 GLREA, Mr. Keskey.

6 MR. KESKEY: Thank you. Pursuant to the
7 agreement of the parties, I would like to move to enter
8 into the record the prefiled Direct Testimony of GLREA
9 expert John Richter into the Public Record, and this is
10 exactly the same testimony that was filed on June 5,
11 2026, and provided to all the parties on that date. In
12 addition, I would like to move for entry into the record
13 the one exhibit that John Richter has sponsored, which is
14 GLREA Exhibit 1, which is a two-page exhibit consisting
15 of his resume. And with that, this testimony has been
16 provided to the court reporter along with the exhibit and
17 the exhibit list, and with that, it would be the
18 completion of GLREA's evidentiary case in this matter.

19 JUDGE STALEY: Thank you, Mr. Keskey. Is
20 there any objection to the binding in of the prefiled
21 Direct Testimony of John Richter, or the admission of
22 Exhibit GLREA-1?

23 Hearing none, the prefiled Direct
24 Testimony of John Richter is bound into the record, and
25 Exhibit GLREA-1 is admitted into evidence. Thank you,

Penn Reporting, LLC - lori.penn@yahoo.com

1 Mr. Keskey.

2 MR. KESKEY: Thank you.

3 (Direct Testimony bound in.)

4 - - -

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of)
DTE ELECTRIC COMPANY)
for approval of special contracts and for other relief.)

Case U-22058

DIRECT TESTIMONY
AND EXHIBIT
OF
JOHN RICHTER

On Behalf of
Great Lakes Renewable Energy Association

June 5, 2026

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1 **II. QUALIFICATIONS**

2 **Q. Please state your name and business address.**

3 A. My name is John Richter, and I have no business address, because I am retired.

4 **Q. Who are you representing, and what is your title and role there?**

5 A. I'm representing The Great Lakes Renewable Energy Association (GLREA). I am on the
6 Board of Directors. I am also the Chairman of the Policy Committee.

7 **Q. Who is the GLREA?**

8 A. The GLREA is a 501(c)(3) (non-profit) corporation based in Michigan. Our Mission
9 Statement is to "Promote the Use of Renewable Energy in Michigan and in the Great
10 Lakes Region, By Empowering Our Members and the Public Through Advocacy,
11 Education and Strategic Collaboration." And our Vision Statement is: "We believe that
12 current and emerging clean, renewable energy solutions can provide 100% of the electrical
13 energy demand in the Great Lakes Region. Furthermore, we believe that increasing
14 development and access to clean, renewable energy that is locally produced, operated and
15 utilized supports economic development, creates new good paying jobs and is essential to
16 supporting healthier, more resilient communities that advance climate justice."

17 **Q. Please describe your educational background.**

18 A. I received a Bachelor of Science degree in Computer Engineering, with a minor in
19 Economics, from Oakland University in 1982. I did some graduate work in software
20 engineering at both Oakland University, and University of Detroit, Mercy. I did some
21 alternative energy coursework at Oakland Community College. I received a Master of
22 Science in Renewable Energy from Murdoch University in Perth, Australia in 2009. I've

1 been through training at Michigan State University's Institute for Public Utilities
2 Regulatory Research and Education's courses on rate making, and "grid school."

3 **Q. Please describe your relevant business experience.**

4 A. At Frontier Communications, I was the Senior Manager of Hardware Integration. In this
5 role, I performed request for proposals (RFPs) and request for quotes, set up the criteria for
6 evaluating the responses, engaged in purchase negotiations, and performed project
7 management for equipment installation, testing, and turn-up. I had a \$25M capital budget
8 for equipment purchases. I also created the Company's capacity forecasting model, and did
9 net present value (NPV) analysis to determine which equipment sites should be closed and
10 consolidated. I was promoted to Director, Product Platform Development, where I again
11 did RFPs and equipment selection. As a Sr. Product Development Manager at Global
12 Crossing, I created new business processes in support of new product launches.

13 During 2002, I consulted on renewable energy policy for the GLREA (among others). In
14 that role, I did a presentation to Michigan legislators and staff on policies to incentivize
15 renewable energy deployments. I was one of three invited presenters to the Northeast and
16 Midwest Caucus meeting on a national RPS at the U.S. Capitol Building. And I was a
17 member of the MPSC Collaborative on Renewable Energy. Under contract with American
18 Council for an Energy Efficient Economy, I wrote a white paper on energy efficiency
19 policy, which was presented to the Governor of Michigan. I was also featured in the PBS
20 documentary film, *Michigan's Green Energy Economy*.

21 In 2010 and 2011, I was an adjunct instructor at Macomb Community College, teaching a
22 course on solar energy. My resume is provided as **GLREA Exhibit-1 (JR-1)**.

1 **Q. Have you previously presented testimony before the Michigan Public Service**
2 **Commission (“MPSC” or the “Commission”)?**

3 **A. Yes, in the following cases:**

- 4 ○ U-18091, DTE Energy PURPA case (remand)
- 5 ○ U-18232, DTE REP (reopened)
- 6 ○ U-20165, Consumers Energy IRP case
- 7 ○ U-20359, Indiana Michigan Power rate case
- 8 ○ U-20471, DTE Energy IRP
- 9 ○ U-20561, DTE Energy Rate case
- 10 ○ U-20713, DTE Energy Renewable Energy Plan
- 11 ○ U-20836, DTE Energy Rate case
- 12 ○ U-21090, Consumers Energy IRP case
- 13 ○ U-21172, DTE Energy Voluntary Green Price
- 14 ○ U-21193, DTE Energy IRP
- 15 ○ U-21375, DTE Energy Voluntary Green Power case
- 16 ○ U-21534, DTE rate case
- 17 ○ U-21816, Consumers Renewable Energy Plan
- 18 ○ U-21972 Consumers Energy Voluntary Green Price

1 **Q. What is the purpose of your direct testimony?**

2 A. The purpose of my direct testimony is to:

3 1. provide useful input on the proposed contracts for service to the Google LLC data center,
4 recommending approval of the contracts if the Commission adds conditions bearing on
5 DTEE (not Google LLC).

6 2. recommend actions that will mitigate risks to other ratepayers created by data centers as a
7 group, which neither these contracts nor the existing D11 tariff address.

8 **Q. Are you sponsoring any exhibits?**

9 A. Yes:

10 **Exhibit GLREA-1** Resume of John Richter

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

12 A. Yes.

13 **III. BACKGROUND**

14 **A. TSUNAMI OF DATA CENTER PROPOSALS**

15 **Q. What is a data center?**

16 A. Amazon Web Services (AWS), one of the largest computing service companies defines a
17 data center as:

18 “A data center is a physical location that stores computing machines and
19 their related hardware equipment. It contains the computing infrastructure
20 that IT systems require, such as servers, data storage drives, and network
21 equipment. It is the physical facility that stores any company’s digital
22 data.”¹

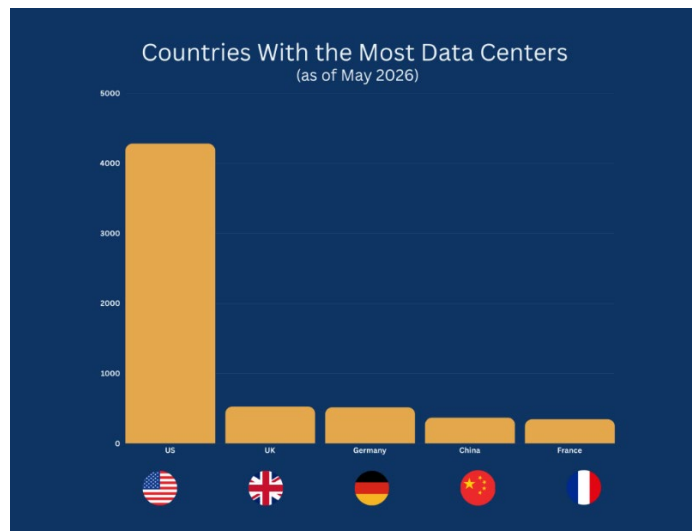
¹ Amazon Web Services, “What is a Data Center”. Accessed on 5/27/26 at:

1 **Q. How many data centers there, and where are they?**

2 A. There are more than 11,000 data centers in the world today, and the US has eight times as
3 many as any other country.²



4



5

<https://aws.amazon.com/what-is/data-center/>

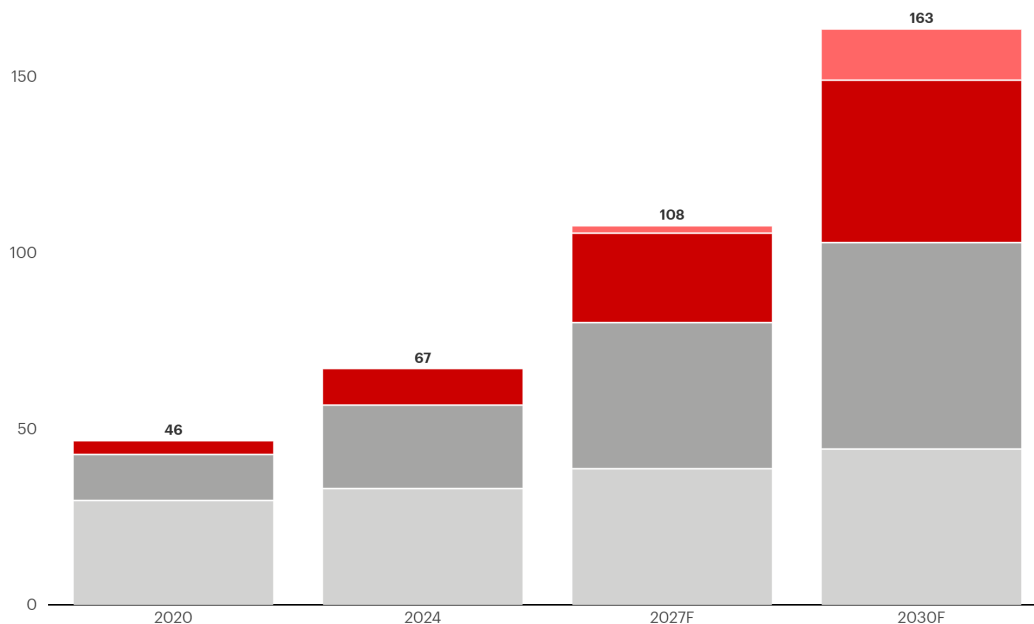
² "Measuring the Data Center Boom: Facts and Statistics (2026)," *programs.com*, May 11, 2026. Accessed on 5/27/26 at: <https://programs.com/resources/data-center-statistics/> and citing data

1 **Q. Data centers have been around for decades, why have they become an issue for the**
2 **grid only recently?**

3 A. The term “data center” is extremely broad. Many of the older data centers are tiny by
4 today’s standards. In 2024, the average data center had a load of only 4 MW.³ In 2020,
5 there were only 46 data centers in the world larger than 250 MW of load. Today, we’re
6 planning data centers more than 38 times that size:⁴

Global data center capacity by size (gigawatts)

■ Data centers with less than 50 megawatts capacity ■ 50-249 megawatts ■ 250-999 megawatts ■ 1 gigawatt and greater



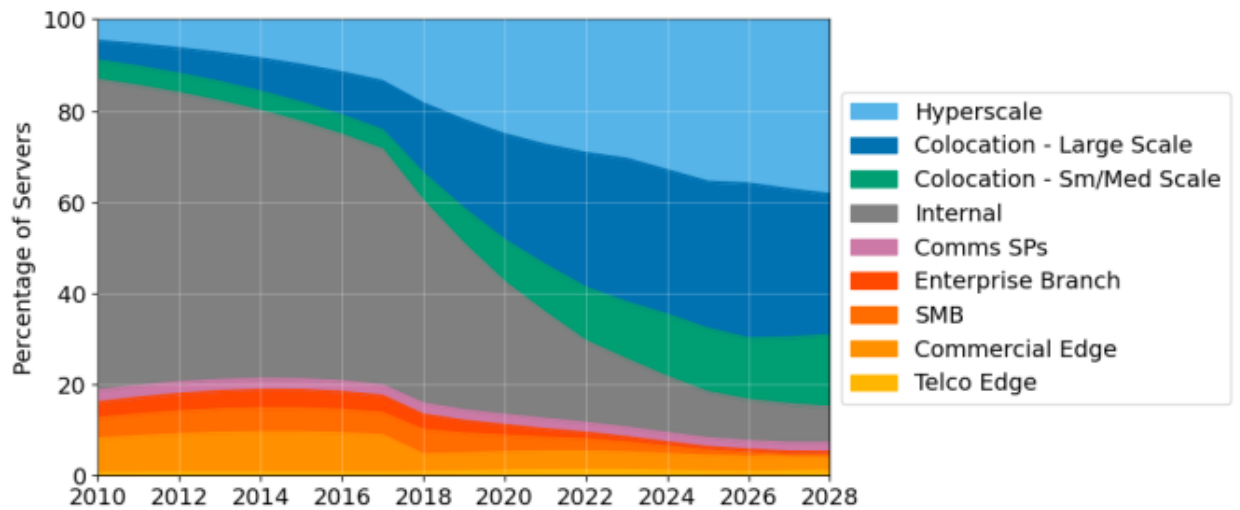
Notes: Assumes baseline scenario of sector growth; values are rounded
Source: Bain Data Center Model, 2025

from: <https://www.datacentermap.com/>

³ Ibid

⁴ Padraic Brick, Tatum Quinn, Peter Hanbury, Aaron Denman, and Alessandro Cannarsi, “AI Data Center Forecast: From Scramble to Strategy,” *Bain & Company*, accessed on 5/27/26 at: <https://www.bain.com/insights/ai-data-center-forecast-from-scramble-to-strategy-snap-chart/> ; Clearview reports that the Delta Gigasite data center in Millard, UT is expected to draw 9,700 MW. Accessed on 5/28/26 at: <https://cleanview.co/data-centers/us>

1 As a result, over time, larger data centers will dominate:⁵



2 **Figure 4.1. Distribution of servers by data center type.**

⁵Arman Shehabi et al, "2024 United States Data Center Energy Usage Report," *LBL Publications*, December 2024, p 37. Accessed on 5/27/26 at: <https://escholarship.org/uc/item/32d6m0d1>

1 **Q. What are these data centers being used for?**

2 A. While many existing data centers are being used for traditional data processing, supporting
3 websites or streaming, most of the new data center proposals are for artificial intelligence
4 (AI). It's estimated that by 2030, 50%⁶ to 70%⁷ of data center computing will be for AI.
5 There are two distinct AI activities: training a new AI model, or answering queries made to
6 the AI, which is called "inference." The AI industry's focus is moving from training to
7 inference, as it moves from development to sales.⁸

8 **Q. How much energy can it take to train a new AI model?**

9 A. Each new model is more complex and requires more processing and energy. For example,
10 training the AI model ChatGPT-3 consumed 1,300 MWh.⁹ It's successor, ChatGPT-4,
11 consumed 50 GWh - 38 times as much energy.¹⁰

⁶ Padraic Brick, Tatum Quinn, Peter Hanbury, Aaron Denman, and Alessandro Cannarsi, "AI Data Center Forecast: From Scramble to Strategy," *Brain & Company*, accessed on 5/26/26 at: <https://www.bain.com/insights/ai-data-center-forecast-from-scramble-to-strategy-snap-chart/>

⁷ McKinsey Quarterly, slide 3 "The AI effect." Accessed on 5/26/26 at:

<https://www.mckinsey.com/quarterly/the-five-fifty/five-fifty-more-data-more-demand>

⁸ Digital Ocean, "AI Inference vs Training: Key Differences Explained," February 27, 2026.

Accessed on 5/27/26 at: <https://www.digitalocean.com/resources/articles/ai-inference-vs-training>

⁹ James Vincent, "How much electricity does an AI consume?," *The Verge*, February 16, 2024.

Accessed on 5/27/26 at: <https://www.theverge.com/24066646/ai-electricity-energy-watts-generative-consumption>

¹⁰ James O'Donnell and Casey Crownhart, "We did the math on AI's energy footprint. Here's the story you haven't heard," *MIT Technology Review*, May 20, 2025. Accessed on 5/27/26 at:

<https://www.technologyreview.com/2025/05/20/1116327/ai-energy-usage-climate-footprint-big-tech/>

1 **Q. How many new data centers are being proposed in the US and in Michigan?**

2 A. In the US, the market intelligence company Clearview is tracking 614 operating data
3 centers with a total load of 18 GW, and 936 planned data centers, with a planned load of an
4 additional 330 GW. In Michigan, Clearview is tracking 2 operating data centers with a
5 load of 3 MW, and 14 planned data centers with a planned load of 2,964 MW¹¹ Their list
6 did not provide a load estimate for the Flex data center proposed in S. Lyon Twp. I
7 attended the data center informational meeting in S. Lyon on January 22, 2026; the
8 representative from developer Verrus stated that the project's load would start at 200 MW
9 and ramp to 525 MW.

10 **Q. How much money is being invested in data center expansion?**

11 A. It is difficult to comprehend the size of this industry. The Wall Street Journal compared the
12 capital investment of the four largest US tech companies as a percentage of the US Gross
13 Domestic Product (GDP) and found that it exceeded the percentage of GDP spent on the
14 US railway system at its peak development, the US interstate highway system, or the
15 Apollo space program.¹²

¹¹ Clearview, "Data Centers in the United States", and "Data Centers in Michigan," last updated May 2026. Accessed on 5/27/26 at: <https://cleanview.co/data-centers/us> and <https://cleanview.co/data-centers/michigan>, respectively

¹² Meghan Bobrowsky, Drew An-Pham, and Alana Pipe, "Big Tech's AI Push Is Costing a Lot More Than the Moon Landing," *The Wall Street Journal*, February 7, 2026. Accessed on 5/27/26 at: <https://www.wsj.com/tech/ai/ai-spending-tech-companies-compared-02b90046?pos=1&page=1> (paywall)

Spending as percentage of GDP, annual average

Louisiana Purchase (1803)

3.0%

Projected capital spending for Meta, Amazon, Microsoft and Alphabet in 2026

2.1%

U.S. railroads (1850-59)

2.0%

U.S. interstate highway system (1955-70)*

0.4%

Apollo space program (1960-73)

0.2%

*Federal highway spending

Sources: National Archives and Measuring Worth (Louisiana Purchase); the companies (Tech capital spending); Visible Alpha (projected Microsoft capital spending) Louis P. Cain (U.S. Railroads); Robert Gordon (U.S. interstate highway system); Planetary Society (Apollo); Wall Street Journal calculations (all ratios)

1
2 Data center capital investment hit \$770 B in 2025.¹³ For comparison, the aggregate capital
3 investment for 47 US investor- owned energy utilities was \$215B in 2025.¹⁴ In the first
4 half of 2025, data center development and IT accounted for 92% of the growth in US
5 GDP.¹⁵ It's simply astounding.

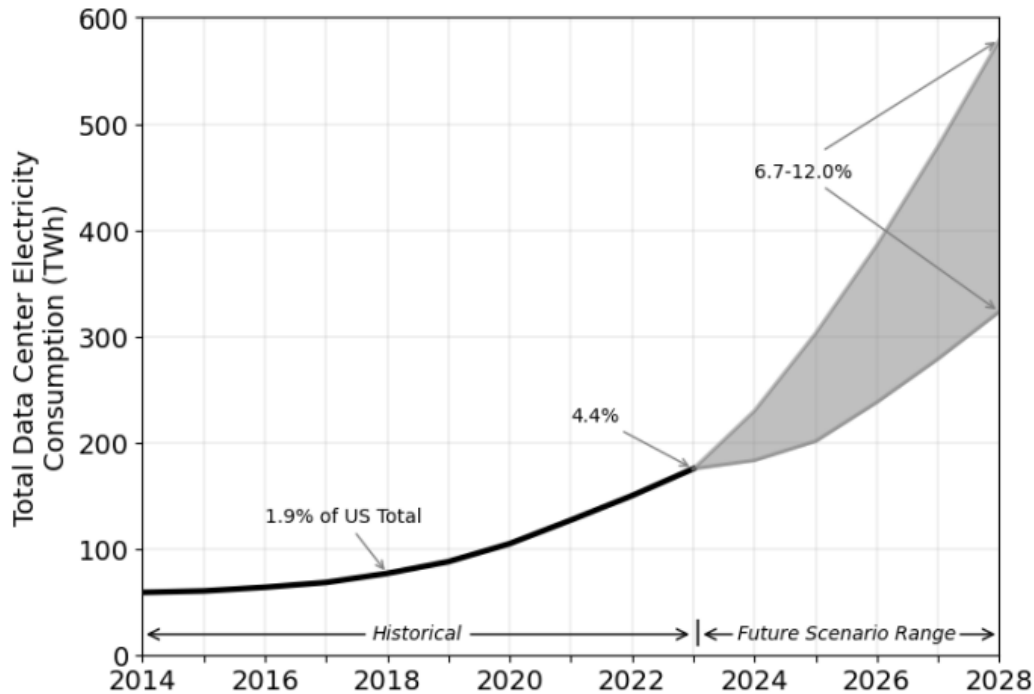
¹³ Rystad Energy, "Putting things in perspective: Data center investments now on par with renewables, oil and gas," March 25, 2026. Accessed on 6/3/26 at: <https://www.rystadenergy.com/insights/putting-things-in-perspective-data-center-investments-now-on-par-with-renewables>

¹⁴ Jason Lehmann, Heike Doerr, and Dan Lowrey, "US utility capex forecast nudges higher on increased generation spending plans," *S&P Global*, September 23, 2025. Accessed on 5/27/26 at: <https://www.spglobal.com/market-intelligence/en/news-insights/research/2025/10/us-utility-capex-forecast-nudges-higher-on-increased-generation-spending-plans>

¹⁵ Nick Lichtenberg, "Without data centers, GDP growth was 0.1% in the first half of 2025, Harvard economist says," *Fortune*, October 7, 2025. Accessed on 5/29/26 at: <https://fortune.com/2025/10/07/data-centers-gdp-growth-zero-first-half-2025-jason-furman-harvard-economist/>

1 **Q. How much will data centers affect demand for electrical energy in the US?**

2 A. Lawrence Berkeley National Laboratories (LBNL) estimates that data centers consumed
3 1.9% of US electrical energy in 2018, and 4.4% in 2023. LBNL projects that by 2028, data
4 centers will consume between 6.7% and 12.0% of US electrical energy.¹⁶



5 **Figure ES-1. Total U.S. data center electricity use from 2014 through 2028.**

¹⁶ Arman Shehabi et al, , “2024 United States Data Center Energy Usage Report”, LBL Publications, December 2024, p 5. Accessed on 5/27/26 at:
<https://escholarship.org/uc/item/32d6m0d1>

1 Jim Robb, president and CEO of the North American Electric Reliability Corp., told a
2 House subcommittee that the rate of increase in electricity demand is “staggering.”
3 Summer peak demand is projected to rise by 200 GW, with winter demand growing faster.
4 “That’s 70% higher than what we projected at this time last year,” Robb said.¹⁷

5 **Q. How much will data centers affect demand for electrical energy in Michigan?**

6 A. That’s difficult to say with any precision. Some proposals become operating data centers,
7 and some never get built. The 1.4 GW Oracle data center under construction in Saline
8 Twp. is projected to ramp to a load of 10,904 GWh/yr.¹⁸ The proposed Google data center
9 will consume 7,884 GWh/year,¹⁹ for a total data center load of (10,904 GWh/yr. + 7,884
10 GWh/yr.) 18,788 GWh/yr. For comparison, DTEE’s current projection of 2026 sales to
11 retail customers is 39,635 GWh.²⁰ Therefore, the combined load of these two data centers
12 will be approximately (18,788 GWh/yr. / 39,635 GWh/yr.) 47% of DTEE’s retail sales.
13 DTEE has said they are in discussions with an additional 6 GW of potential data center
14 projects, over and above the two in Saline Twp. and Van Buren Twp.²¹

¹⁷ Robert Walton, “January’s Winter Storm Fern was ‘classic near-miss’ for US grid, says NERC’s Robb,” *Utility Dive*, March 20, 2026. Accessed on 5/29/26 at: <https://www.utilitydive.com/news/januarys-winter-storm-fern-was-classic-near-miss-for-us-grid-says-nerc/815291/>

¹⁸ U-21990, Exhibit A-3, row 4 “Incremental Data Center Load,” columns (e) through (i)

¹⁹ Direct testimony of K. L. Bilyeu, p KLB-9, Table 1

²⁰ U-21990, Exhibit A-3, row 4, column (c).

²¹ Robert Walton, “DTE sees up to 8.4 GW data center opportunity,” *Utility Dive*, May 1, 2026. Accessed on 5/27/26 at: <https://www.utilitydive.com/news/dte-energy-data-center-earnings-reliability/819052/>

1 Consumers Energy has testified that they have inquiries from over 30 different data center
2 leads that total over 15 GW of load.²² For comparison, as of December 2021, Consumers
3 Energy had a total system generating capacity of 5,300 MW.²³ Intelligence platform
4 Sightline Climate estimates that 30-50% of the US data center pipeline will not be built.²⁴
5 If half of the DTE “potential” projects and half of the Consumers Energy “inquiries” were
6 built, it would represent $(.5 \times 6 \text{ GW}) + (.5 \times 15 \text{ GW}) = 10.5 \text{ GW}$ of additional load.

²² U-21859, Direct testimony of Laura Connolly, 3 Tr 85

²³ Consumers Energy, “Electric Operation Statistics,” December 2021. Accessed on 5/28/26 at:
<https://www.consumersenergy.com/about-us/electric-generation/electric-operations-statistics>

²⁴ Olivia Wang, “Data center outlook: half of 2026 pipeline may not materialize,” *Sightline Climate Outlook*, February 24, 2026. Accessed on 5/28/26 at:
<https://www.sightlineclimate.com/research/data-center-outlook>

1 **B. THE PJM EXPERIENCE**

2 **Q. Have other parts of the US already experienced dramatically higher loads as a result**
3 **of new data centers?**

4 A. Yes, Northern Virginia has been called “data center alley” due to the high concentration of
5 new data centers there. In 2025, Virginia had 12GW of data centers, consuming 40% of the
6 State’s electricity.²⁵ The entire PJM region has seen explosive growth in power demand.
7 Monitoring Analytics, the independent market monitor for the Eastern grid operator PJM
8 Interconnection reported that “PJM attributed almost all of this increase in the summer
9 peak load forecast to the anticipated additions in data center demand.”²⁶
10 Morning Analytics report shows that peak-hour demand was fairly constant from 2014 –
11 2023, varying between 138GW and 144 GW, but rose to 149 GW in 2024 (+3.2%) and 156
12 GW in 2025 (+4.9%), as shown in the table below. These are substantial increases in load
13 for a huge region. PJM’s forecasts of peak load are getting revised upwards every year,
14 projecting a peak load of 164 GW in 2027.²⁷

²⁵ Global Statistics, “AI Data Center Statistics in US 2026,” in table: “US Data Center Energy by State 2026.” Accessed on 6/3/26 at: <https://www.theglobalstatistics.com/ai-data-center-statistics-in-us/>

²⁶ Monitoring Analytics, “Analysis of the 2026/2027 RPM Base Residual Auction Part A” October 1, 2025, p 8. Accessed on 5/29/26 at: https://www.monitoringanalytics.com/reports/Reports/2025/IMM_Analysis_of_the_20262027_RPM_Base_Residual_Auction_Part_A_20251001.pdf

²⁷ Ibid, p 7, Table 1 & 2

Table 1 PJM Peak Load between 2009 and 2025⁸

	Date	Hour Ending (EPT)	PJM Load (MWh)
2009	Mon, August 10	17	123,900
2010	Tue, July 06	17	133,297
2011	Thu, July 21	17	154,095
2012	Tue, July 17	17	150,879
2013	Thu, July 18	17	153,790
2014	Tue, June 17	18	138,448
2015	Tue, July 28	17	140,266
2016	Thu, August 11	16	148,577
2017	Wed, July 19	18	142,387
2018	Tue, August 28	17	147,042
2019	Fri, July 19	18	148,228
2020	Mon, July 20	17	141,449
2021	Tue, August 24	17	145,563
2022	Wed, July 20	18	144,356
2023	Thu, July 27	18	144,215
2024	Tue, July 16	18	148,890
2025	Mon, June 23	18	156,256

1

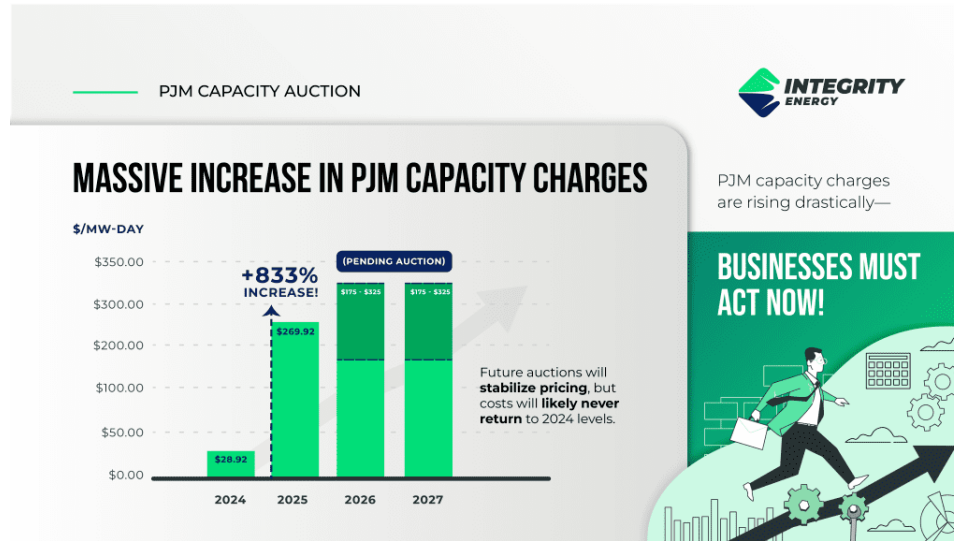
Table 2 Forecasted Summer Peak Load for 2022 through 2026 as reported in the recent load forecast reports⁹

	Forecasted Summer Peak Load (MW)					
Report	2022	2023	2024	2025	2026	2027
2022 Load Forecast	148,938	149,351	150,309	151,165	152,259	152,322
2023 Load Forecast		149,059	149,737	150,924	152,736	154,275
2024 Load Forecast			151,247	153,493	156,803	159,859
2025 Load Forecast				154,144	158,937	164,186

2

1 **Q. How have PJM *capacity* auction prices been affected by increasing load?**

2 A. PJM capacity prices have skyrocketed, increasing from \$28.92/MW-day in 2024 to
3 \$269.92/MW-day in 2025, an 833% increase! The capacity price increased an additional
4 22% in the 2026/27 auction, but would have gone higher if not for an artificial price cap:²⁸



²⁸ Renee Sanders, “How the Latest PJM Auction Impacts 2026–2027 Energy Costs,” *Integrity Energy*, July 24, 2025. Accessed on 5/29/26 at:

<https://www.integrityenergy.com/resources/about-us/news-media/pjm-announces-expensive-energy-changes-in-2026/>

1 A report from Monitoring Analytics put the responsibility for this increased load
2 squarely on data centers:

3 “There are clear warning signs for the capacity market and for PJM
4 reliability. The capacity market was short of reaching its reliability
5 objective in the most recent capacity auctions... PJ was also short of
6 meeting its reliability target as of June 1, 2025... *Data center load growth*
7 *is the primary reason* for recent and expected capacity market conditions,
8 including total forecast load growth, the tight supply and demand balance,
9 and high prices. *But for data center growth*, both actual and forecast, the
10 capacity market would not have seen the same tight supply demand
11 conditions, the same high prices observed in the 2025/2026 BRA, the
12 2026/2027 BRA, and the 2027/2028 BRA, and the currently expected tight
13 supply conditions and high prices for subsequent capacity auctions.”²⁹
14 (emphasis added)

15 **Q. Did the market monitor make any recommendations to address the steep increase in**
16 **data center load’s impact on the PJM capacity market?**

17 A. Yes, Morning Analytics recommended that data centers be required to bring their own new
18 generation. They assert that this would prevent “wealth transfers” – what I would call
19 cross-subsidies:

²⁹ Morning Analytics, “State of the Market Report for PJM, 2025,” March 12, 2026, p 1.
Accessed on 5/29/26 at:

https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2025/2025-som-pjm-vol1.pdf

“It is clear that continuing to simply accept the interconnection of large data center loads that cannot be served reliably because there is not adequate dispatchable capacity, is not a reasonable path forward... There is not enough capacity currently to meet the data center load. The solution is not to create reliability issues and *wealth transfer issues* by clearing the capacity market at the maximum price and at a quantity less than the reliability requirement by allowing the ongoing interconnection of large data center loads without adequate generation to serve them... The market solution is to require data centers to bring their own new generation. This would include an expedited fast track load and generation interconnection process for large new data center loads that bring their own new generation with locational and temporal characteristics reasonably matched to their load profile. *The preferred solution would include creating a queue* for the addition of large new data center loads, which would not be interconnected until there is adequate capacity to serve them. Another solution would require data centers that do not bring their own new generation to be *curtailable prior to current demand side customers but without the pretense that the data centers are providing “demand response” for which they should be paid.* Given the level of data center load growth, this curtailability solution would provide a strong incentive to bring new generation, if enforced on a specific data center basis. *This broad bring your own new generation solution to the issues created by the addition of unprecedented amounts of large data center load does not require a continued massive wealth transfer.*”³⁰ (emphasis added)

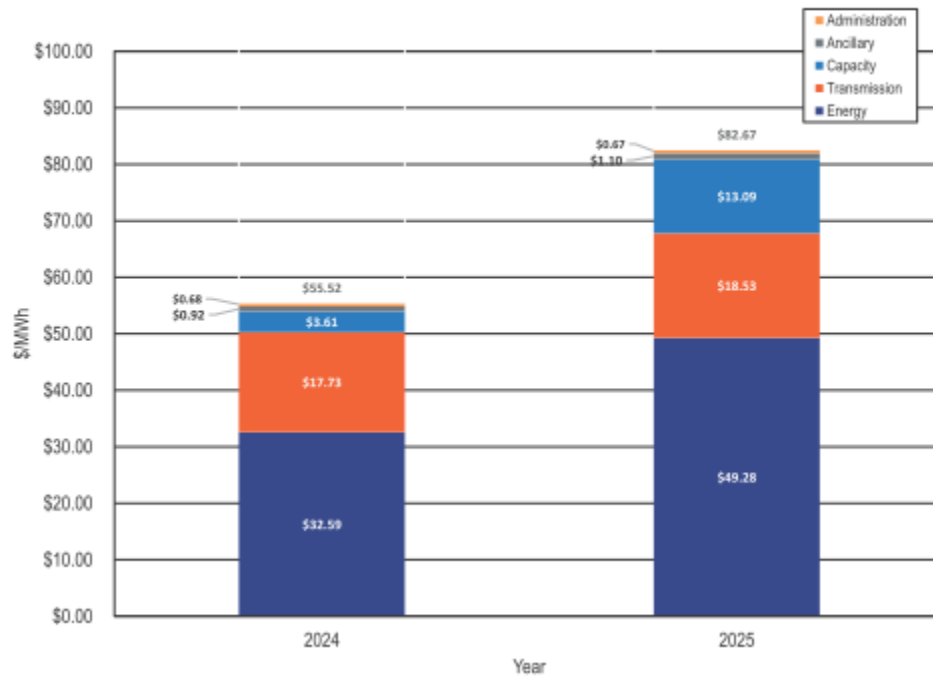
Q. Did PJM wholesale auction energy prices also increase significantly?

A. Yes, from 2024 to 2025 the cost of wholesale energy increased from \$32.59/MWh in 2024 to \$49.28/MWh in 2025, an increase of 51.2%.³¹ Monitoring Analytics tracks the total cost of wholesale power, which includes the cost of capacity, transmission, and ancillary services. The total cost per MWh increased by 54%. A graphic shows the contribution of each of the components to the price increase; both energy and capacity prices contributed to the overall increase:³²

³⁰ Ibid, p 2

³¹ Ibid, p 17, table 9, the first row labeled “Energy”

³² Ibid, p 17

Figure 3 Total cost per MWh by category: 2024 and 2025

1

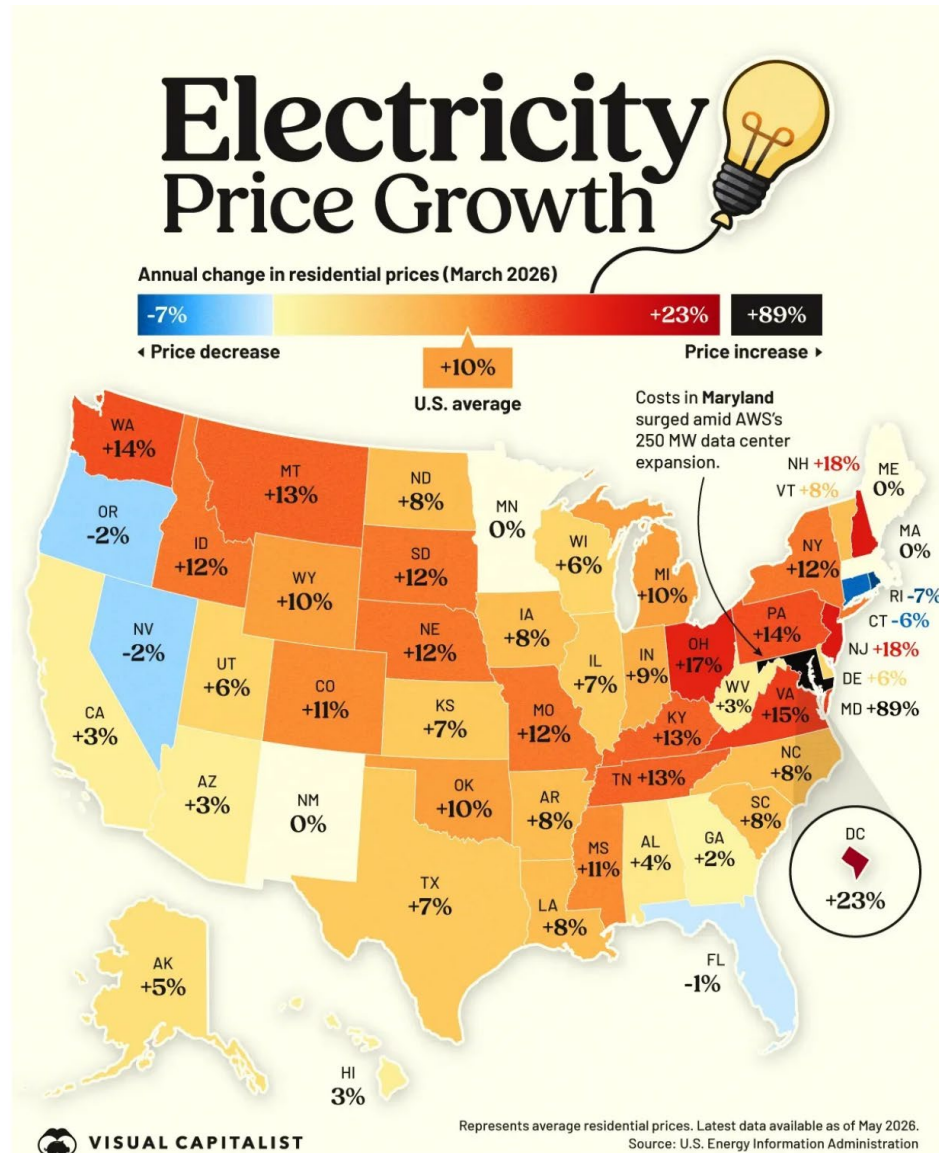
2 **Q. Did the PJM State of the Market report address the cause of the increase in the**
 3 **market price of energy?**

4 A. Yes, though not as definitively as it did with the increase in capacity price: “Data center
 5 load growth affects energy market prices. Increased demand puts upward pressure on
 6 prices, all else equal. It is difficult to shield customers from the costs caused by data center
 7 load growth in the energy market.”³³

³³ Ibid, p 30

Q. Have utilities in the PJM region increased electric rates significantly in the past two years?

A. Yes. Here is a graph showing 12-month electric rate increases in the US, as of May, 2026:³⁴



³⁴ Dorothy Neufeld, "Mapped: Where Electricity Prices Jumped the Most in America," *Visual Capitalist*, June 1, 2026. Accessed on 6/3/26 at: <https://www.visualcapitalist.com/mapped-where-electricity-prices-jumped-the-most-in-america/>

1 The accompanying chart shows that six of the eight states with the largest increases in
2 electric rates are in the PJM region (at least partly); New Hampshire and Washington are
3 not in the PJM region:³⁵

Electricity Price Growth by State

The following table shows the annual change in average residential elect
March 2026.

10 ▾

entries per page

Search:

Rank ▴ ▾	State	Annual Change in Residential Electricity Prices Mar 2026
1	Maryland	89.3%
2	District of Columbia	22.5%
3	New Jersey	18.2%
4	New Hampshire	18.0%
5	Ohio	16.6%
6	Virginia	14.5%
7	Washington	14.1%
8	Pennsylvania	13.6%
9	Montana	13.0%
10	Tennessee	12.8%
--	us U.S. Average	10.2%

4

³⁵ Ibid

1 **IV. GOOGLE LLC CONTRACT EVALUATION**

2 **Q. What is your overall opinion of the proposed PSA and CCAA contracts?**

3 A. Google LLC has demonstrated a very concerted effort to prevent this data center from
4 impacting other DTE Electric (DTEE) customers, at considerable cost to themselves. It
5 may be impossible to fully and absolutely insulate other ratepayers from the impacts of this
6 data center, but they've demonstrated a willingness to do more than the minimum
7 necessary to get connected. These contracts provide significantly greater protections for
8 other ratepayers over the Green Chile Ventures LLC contracts, approved in U-21990, with
9 the *possible* exception of the capacity impact.

10 **Q. In what ways do these contracts provide more protection to other ratepayers, when**
11 **compared to the contracts in U-21990?**

12 A. To begin with, the Google LLC contracts are being assessed in a contested case, while U-
13 21990 was decided ex parte. Reportedly, this is a result of a promise that Google made
14 directly to the Michigan Attorney General (AG).³⁶ Google is committing to funding 1,600
15 MW of renewable energy, vs. zero MW in U-21990. Google is undertaking their own
16 EWR program, rather than relying on DTEE to do so. Google's termination fee is 15 years
17 of Minimum Billing Demand (MBD), vs. 10 years in U-21990. Google is paying \$50M
18 for transmission upgrades.

³⁶ Michigan Dept. of Attorney General, "AG Nessel on Newly Announced Google Data Center Proposal: Google Commits to Contested Case at MPSC," March 17, 2026. Accessed on 5/31/26 at: <https://www.michigan.gov/ag/news/press-releases/2026/03/17/ag-nessel-on-newly-announced-google-data-center-proposal>

1 The two developers have both provided capacity to meet their demand; Green Chile
2 Ventures LLC very directly by funding enough battery storage for their full load, and
3 Google through a complex mix of funded battery storage, temporary demand response, and
4 the purchase of ZRCs. The capacity resources funded in the Green Chile Ventures LLC
5 contract are certainly easier to understand than the mix of resources provide by Google,
6 and may offer somewhat better protection. However, Google's PSA mitigates capacity risk
7 with a load commitment off-ramp.

8 **Q. What is the load commitment off-ramp in the Google PSA?**

9 A. The Google LLC Power Supply Agreement (PSA) includes an off-ramp if DTEE is unable
10 to meet the customer's load ramp, for any of a variety of specified reasons. The DTEE and
11 the customer agree to negotiate a solution to the shortfall, but DTEE retains the option to
12 "unilaterally propose an adjustment to the Customer's load ramp or max load," leaving the
13 customer the option of acceptance of a lower capacity or terminating the agreement and
14 paying the (very large) termination fees.³⁷ Google has accepted a significant risk, rather
15 than impose that risk on DTEE's customer base.

³⁷ Direct testimony of N. T. Foley, p NTF-16-17, quoting p 17 lines 16-17

Q. Is there any additional provision in the Google PSA that protects other ratepayers?

A. Yes, the Google LLC PSA includes a backstop provision to ensure that the cost to serve the customer does not exceed the revenue paid by the customer. Triggering this provision requires a ruling by the Commission.³⁸ While the Commission always has the ability to increase a rate if it is insufficient to recover caused costs, presumably there will be more than one customer using the same rate sheet, and any change to the rate affects all of those customers. Additionally, cost allocation is done for the entire customer class, not a specific customer. Therefore, this clause provides significant protection to other customers if, in the future, the Commission chooses to invoke it.

Q. Does this application provide all the protections that the Commission approved in Consumers Energy's amendments to rate GPD (U-21859) and DTE's special contracts for Green Chile Ventures LLC (U-21990)?

A. For the most part, the contracts do provide the protections required in those case orders. I have summarized the protections in the table below:

Customer Protection	Protection Ordered	Source³⁹	Provided in this Application?
Size for large load provisions	100 MW or more	U-21859 p 105	Yes, 1 GW contract
Term length	U-21859: 15-yr term, 5-yr extensions U-21990: 19-year term, two 10-yr extensions	U-21859 p 107-8 U-21990 p 5	Yes. 20 yr term, 5-yr extensions w/3-yr notice
Load shortfall	80% MBD	U-21859 p 108	Yes. 80% MBD

³⁸ Ibid, p NTF-20

³⁹ "Source" is the page number in either U-21859, Commission ordered dated Nov 6, 2025, or U-21990, Commission order dated December 18, 2025

Exit fee	U-21859: MBD times remaining months U-21900: at least 10 years	U-21859 p 109-10 U-21990 p 6	Yes. 15 yr exit fee
Load reduction	One-time 10% w/4-yr notice	U-21859 111	unknown
Collateral	U-21859: 50% of remaining contract MBDs; no parent guarantee required. U-21990 Parent guarantee, credit risk is borne by DTEE	U-21859 p 112-3 U-21990 p 8, 41	Discussion below.
Cost allocation	U-21859 Next rate case; 6 CoS required U-21990 Next rate case; 6 CoS required	U-21859 p 114-6 U-21990 p 39-30	Same
Cost shifting	ex parte filing per customer	U-21859 p 117	Yes, but contested
Renewable energy	discuss VGP w/customers	U-21859 p 119	1600 MW funded as Special VGP project
Reporting	U-21859: Annual data center MW, MWh, capacity reductions/increases, exits and exit fees U-21990: quarterly load profile, operational storage, demand vs. contract, changes to credit rating, financial assessment	U-21859 p 120 U-21990 p 42	None found in application
Interconnect standards	exiting rules OK	U-21859 p 122	Same by default, not addressed
Administrative fee	U-21859: \$100K U-21990: next rate case	U-21859 p 123	None found in application
Battery costs	Customer bears all costs over 15-year period, credits = MISO market revenue net of charging costs	U-21990 p 4	Similar, but a smaller system
Load Shed	Customer is shed first, update emergency procedures	U-21990 p 41	Covered under U-22059

1 **Q. With regard to collateral, what customer protections were provided the U-21990,**
2 **which are not included in DTEE’s application in the instant case?**

3 A. In a contract of this scale, the risk of customer default (no matter how unlikely it appears)
4 could be so massive that it requires careful evaluation. The credit rating of the customer,
5 the credit rating of its parent (if parent guarantees are provided), and the quality of the
6 collateral are all central to this evaluation. The Company clearly has more expertise in this
7 kind of financial risk evaluation than the Commission or Staff. Since the Company
8 negotiated the terms, conditions, any guarantees, and the collateral, the responsibility for
9 that evaluation falls on the Company. The Commission’s order should clearly restate the
10 position that it properly and firmly asserted in U-21990:

11 “In addition, in the event of a failure to pay the MBD under the PSA, or in
12 the event of a termination, default, or other event whereby DTE Electric is
13 required to draw on the letter of credit or parental guaranty, if the
14 company determines that the specified collateral is not sufficient to cover
15 the full amount of the remaining financial exposure associated with the
16 ESA or the PSA (minus the value to customers), the Commission
17 specifically cautions DTE Electric that any unrecovered costs *shall not be*
18 *borne by ratepayers* and that DTE Electric bears responsibility for any
19 remaining liability. *All risk associated with the sufficiency of the*
20 *collateral shall be borne by DTE Electric.*”⁴⁰ (emphasis added)

⁴⁰ U-21990, Commission order dated December 18, 2025, p 41

1 **Q. Are there reporting requirements in the application?**

2 A. Not that I found. In U-21859, there were significant annual reporting requirements for the
3 Company to provide on all their large load customers.⁴¹ In U-21990, the Commission
4 ordered DTE to file a quarterly report in the docket, and annual reporting requirements as
5 well.⁴² That requirement is reasonable and prudent, and the Commission should include
6 those reporting requirements in the instant case as well.

7 With increasing numbers of large load customers, the Commission

8 **Q. Outside of the contracts themselves, are there requests in the application that the**
9 **Commission should address?**

10 A. Yes. The customer has agreed to purchase ZRCs on the market and transfer them to
11 Company. This helps reduce the impact of the customer's load on the Company's grid, to
12 the benefit of other customers. The customer has also agreed to pay the Company a fee for
13 having transferred the ZRCs:

14 "In addition, the Customer has agreed to pay the Company an amount
15 based on the Financial Compensation Mechanism ("FCM") that the
16 Company is authorized to receive for PPAs it enters into associated with
17 clean energy projects. More specifically, the Customer will pay the
18 Company an amount equal to the ZRCs transferred to the Company
19 multiplied by MISO Cost of New Entry ("CONE") multiplied by the
20 Company's pre-tax weighted average cost of permanent capital ("financial
21 adder"). The Company is proposing that it be allowed to record this
22 amount as non-refundable income, like it does with the FCM."⁴³

23 And also:

⁴¹ U-21859, Commission order dated November 6, 2025, p 120

⁴² U-21990, Commission order dated December 18, 2025, p 42

⁴³ Direct testimony of N. T. Foley, p NTF-32, lines 1-8

1 “Summary of Requested Commission Action... Ability to record the
2 financial adder related to the transferred ZRCs addressed in the CCAA as
3 non-refundable income.”⁴⁴

4 The contract formula, “ZRCs multiplied by CONE,” represents a reasonable value
5 associated with the capacity the ZRCs represent. It is unclear to me why the customer
6 would pay the Company to take the ZRCs the customer has purchased; it seems like double
7 payment. But I have no objection to any fee that the customer agrees to pay the Company,
8 so long as that fee is ordinary revenue, and does not become part of DTEE’s profit. The
9 “FCM” that DTEE references above is added profit that the Company gains for entering
10 into PPAs or third-party storage contracts, per MCL 460.1028. A customer giving DTE
11 ZRCs does not qualify for added profits under MCL 460.1028, which says nothing about
12 capacity or ZRC transfers. There is no need to reject the contract due to this issue. The
13 Commission should simply deny the Company’s accounting request, and treat this fee as
14 ordinary revenue.

15 **V. UNRESOLVED RISKS**

16 **Q. Earlier in your testimony, you said that, “It may not be possible to fully and**
17 **absolutely insulate other ratepayers from the impacts of this data center.” What are**
18 **the potential impacts and risks that other ratepayers will still be exposed to, if these**
19 **contracts are approved and the data center starts operation?**

20 **A.** The remaining risks are not particular to *this* data center, but apply to all hyperscale data
21 centers. I will discuss three remaining risks in sequence:

⁴⁴ Ibid, p NTF-43 line 16 and p NTF-44 lines 3-4

- 1 1. The risk to grid reliability resulting from data centers' very rapid variations in load
- 2 when doing AI training.
- 3 2. The risk to power quality resulting from harmonics and sub-harmonics fed back into
- 4 the grid by the data center.
- 5 3. The risk that DTEE will be unable to meet the 2030 Renewable Energy Standard
- 6 (RES) and will apply for an extension, as authorized in MCL 460.1032.
- 7 4. The risk that the combined load of data centers in MISO and the entire US will cause
- 8 scarcity pricing, driving up utility costs and other customer's rates indirectly.

9 **A. Transient Events**

10 **Q. What is the risk to reliability resulting from very rapid variations in data center**
 11 **load?**

12 A. When training a new AI model, data center load may vary wildly in milliseconds or even
 13 *microseconds:*

14 “A.I.-related data centers, though, operate differently, with demand
 15 profiles that can shift dramatically from second to second. This is
 16 especially true for training operations when tasks might be spread across
 17 many graphics processing unit servers at a time. These power-hungry
 18 devices can ramp up in unison in seconds or even microseconds, driving
 19 demand spikes. Operations can then power down just as rapidly, which
 20 can create a surge on the connected grid. As a result, these facilities can
 21 affect grid reliability across a utility's network.”⁴⁵

22 Uptime Institute explains this common AI training phenomenon in more detail:

⁴⁵ Chuck Ross, “It’s not just the load: A.I. data center grid impacts,” *Electrical Contractor*, January 15, 2026. Accessed on 6/2/26 at: <https://www.ecmag.com/magazine/articles/article-detail/it-s-not-just-the-load--a.i.-data-center-grid-impacts>

1 “Uptime Intelligence estimates that in worst-case scenarios, the difference
2 between the low and high points of power draw during training program
3 execution can exceed 100% on a system level (the load doubles almost
4 instantaneously, within milliseconds) for some configurations.

5 *These extremes occur every few seconds*, whenever a batch of weights and
6 biases is loaded on GPUs and the training begins. This is often
7 accompanied by a massive spike in current, produced by power excursion
8 events as GPUs overshoot their thermal design power rating (TDP) to
9 opportunistically exploit any extra thermal and power delivery budget
10 following a phase of lower transistor activity. In short, power spikes are
11 made possible by intermittent lulls.

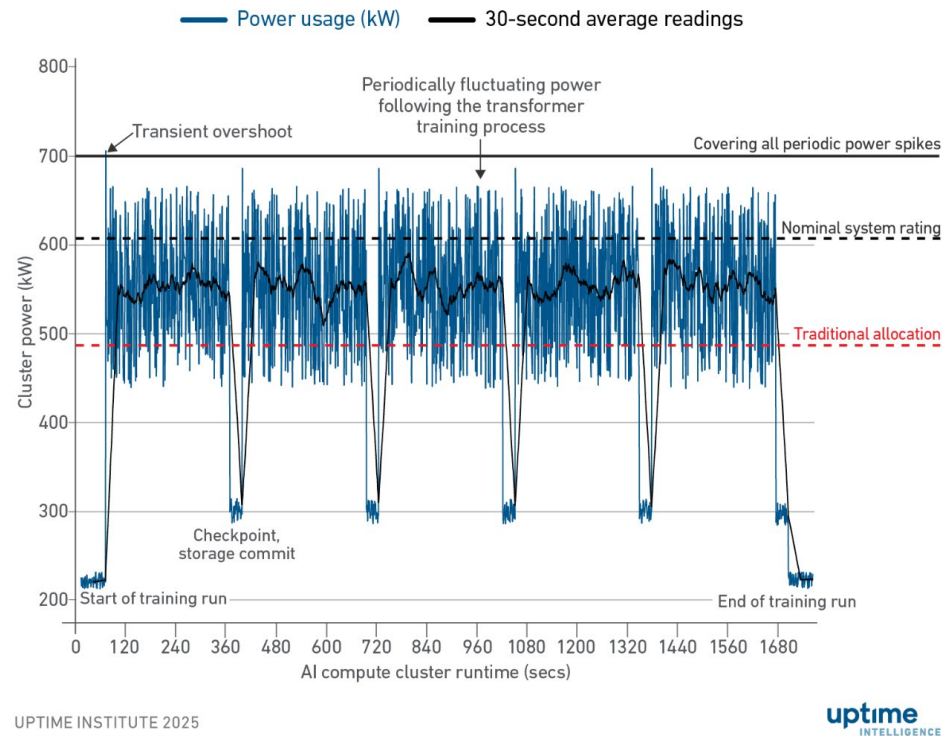
12 This behavior is common in modern compute silicon, including in
13 personal devices and generic servers. Still, it is only with large AI
14 compute clusters that these fluctuations across dozens or hundreds of
15 servers move almost synchronously.”⁴⁶ (emphasis added)

16 Uptime goes on to explain that a server cluster can spike over its rated load, and provides a
17 graph of a training cluster’s load over time, illustrating the spikes over rated load.⁴⁷

⁴⁶ Daniel Bizo, “Electrical considerations with large AI compute,” Uptime Institute, November 19, 2025. Accessed on 6/2/26 at: <https://journal.uptimeinstitute.com/electrical-considerations-with-large-ai-compute/>

⁴⁷ Ibid

Figure 1 Power profile of a GPU-based training cluster (algorithmic not real-world data)



In electrical terms, no multi-rack workload is perfectly synchronous, while the presence of other loads will help smooth out the edges of fluctuations further. When including non-compute ancillary loads in the cluster — such as storage systems, networks and CDUs (which also require UPS power) — a lower safety margin above the nominal rating (e.g., 10% to 15%) appears sufficient to cover any regular peaks over the nominal system power specifications, even with the latest AI hardware.

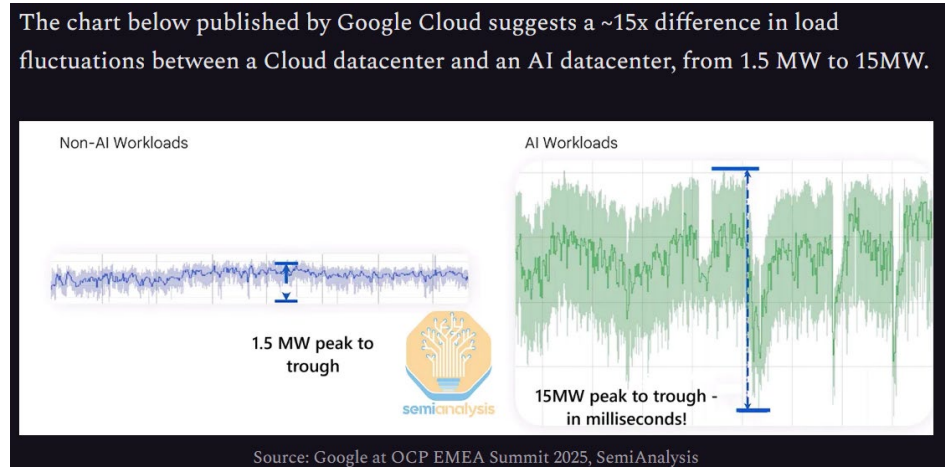
Q. How do these wild swings in power consumption by AI computing clusters affect the grid?

A. Semi Analysis opens with a bleak warning of the consequences of these load swings, before turning to a more technical description:

“Not only is the scale massive, but AI training workloads have a very unique load profile, unexpectedly rising and falling from full load to nearly idle in fractions of a second. Our power grids were never designed to handle this pattern. At Gigawatt-scale, the worst-case scenario is a blackout for millions of Americans.”⁴⁸

⁴⁸ Jeremie Elliahou Ontiveros, Dylan Patel, and Ajey Pandey, “AI Training Load Fluctuations at the Gigawatt-scale – Risk of Power Grid Blackout?,” *Semi Analysis*, June 25, 2025. Accessed on 6/2/26 at: <https://newsletter.semianalysis.com/p/ai-training-load-fluctuations-at-gigawatt-scale->

Semi Analysis provides a graph, showing how AI systems load swings wildly, but non-AI computing has much smaller changes in power draw:⁴⁹



Semi Analysis goes on to discuss simulations, showing that AI data centers in Texas could trigger cascading power losses resulting in a blackout. It draws a parallel to the massive blackout in Spain and Portugal that started on April 28, 2005 with 2.2 GW of generation tripping off-line, resulting in cascading breaker trips and total collapse within 27 seconds.⁵⁰

Q. Could data centers trigger a similar grid event in the US?

A. This scenario is not far-fetched. A similar trigger began in Northern Virginia on July 10, 2024 resulting in a NERC incident report:

““A lightning arrester failed on a 230 kV transmission line in the eastern interconnection, resulting in a permanent fault that eventually ‘locked out’ the transmission line,” the NERC report said. A lightning arrester is a piece of equipment designed to protect against power surges.

[risk-of-power-grid-blackout](#)

⁴⁹ Ibid

⁵⁰ Ibid

1 This led to a series of short supply disturbances, lasting a matter of
2 milliseconds before the system corrected itself, but it was enough to cause
3 data centers in the area to automatically switch to their backup UPS
4 systems as a precautionary measure because “data center loads are
5 sensitive to voltage disturbances,” the report said.”⁵¹

6 Sixty data centers, using 1,500 MW power, dropped off the grid simultaneously, and did
7 not return to the grid for hours.

8 **Q. Was this event in Virginia an isolated case?**

9 A. No. Reuters reviewed disclosure filings in Texas (ERCOT) and identified “more than 30
10 near-miss incidents since 2020, triggered by big energy users like data centers and crypto
11 miners switching offline.”⁵²

12 **Q. Could this kind of event really cause a major power outage?**

13 A. Yes, according to Alison Silverstein, a former senior adviser to the chairman of
14 the US Federal Energy Regulatory Commission, who said: “What it tells us is
15 that the behavior of data centers has the potential to cause cascading power
16 outages for an entire region.”⁵³

⁵¹ Matthew Gooding, “Virginia narrowly avoided power cuts when 60 data centers dropped off the grid at once,” *Data Center Dynamics*, March 20, 2025. Accessed on 6/2/26 at <https://www.datacenterdynamics.com/en/news/virginia-narrowly-avoided-power-cuts-when-60-data-centers-dropped-off-the-grid-at-once/>

⁵² Tim McLaughlin, “Big Tech’s data center boom poses new risk to US grid operators,” *Reuters*, March 19, 2025. Accessed on 6/2/26 at: <https://www.reuters.com/technology/big-techs-data-center-boom-poses-new-risk-us-grid-operators-2025-03-19/>

⁵³ Ibid

Q. Why would data centers switch to their uninterruptable power System (UPS) due to a voltage fluctuation that lasted only milliseconds, and how could the data centers prevent this behavior?

A. Reuters explains that the settings on the UPSs could be changed, but data centers are concerned with protecting their equipment from voltage variations:

“Many data centers are engineered by their operators to switch to local generators at the smallest hint of a problem on the grid to minimize the risk of an interruption to services like Google search or crypto mining, according to NERC.

Some grid operators have proposed requiring data centers to “ride through” routine voltage dips without disconnecting. But data center operators are opposed because of the risk of damaging electronic equipment and cooling systems.

ERCOT last year withdrew a proposal that would have imposed ride-through restrictions on data centers and crypto miners after facing pushback from an industry group, the Data Center Coalition.

The group, whose members include Amazon, Google, and Meta, cited costs and the risk of damaging computer chips and cooling systems exposed to fluctuating voltage levels.⁵⁴

Q. Isn’t it better to risk damage to some equipment than to risk a blackout?

A. It is easy to understand the data center operator’s concern if you understand the cost of the equipment at risk. Oracle’s co-CEO Clay Magouyrk recently visited the construction site for the Oracle data center in Saline Twp., where he announced that the electronics they will install in that data center will cost \$30-40 *billion*.⁵⁵ Obviously, they want to protect that huge investment.

⁵⁴ Ibid

⁵⁵ Dustin Blitchok, “Data center news: Altman visits Saline data center, says it’s ‘huge bet’ on AI,” *Planet Detroit*, June 1, 2026. Accessed on 6/2/26 at: <https://planetdetroit.org/2026/06/michigan-data-center-news-altman-saline/>

1 **Q. Do Michigan’s current interconnect standards protect the grid from the risk of data**
2 **center transient load causing cascading breaker trips?**

3 A. I don’t know. In U-21859, the Commission cited “Service Quality and Reliability
4 Standards for Electric Distribution Systems, Mich Admin Code, R 460.701 et seq., and the
5 Technical Standards for Electric Service, Mich Admin Code, R 460.3101et seq.,” and
6 noted that they were “recently amended” and became effective in April, 2023.⁵⁶ Based on
7 my online research, this problem was not widely known at that time; an update may be
8 needed to address the risk of transient loads.

9 **Q. Has any other jurisdiction addressed the problem of AI data center transient loads?**

10 A. Yes. ERCOT (in Texas) has data center proposals totaling 450 GW of load. The board of
11 directors of the Electric Reliability Council of Texas recently approved rules that “would
12 require data centers and crypto-mining facilities to stay online and ‘ride through’ brief
13 power interruptions on the grid. If a data center were unable to weather those disruptions
14 under the new plan, it would be ordered to disconnect from the grid until it came into
15 compliance with the new rules”. Data center supporters have opposed the rules arguing that
16 compliance will be costly and take years to implement. The PUC has not yet voted on the
17 proposal.⁵⁷

⁵⁶ U-21589, Commission order dated November 6, 2025, p 122

⁵⁷ Shelby Webb, “Texas advances major grid rules for data centers,” E&E News, June 3, 2026.
Accessed on 6/4/26 at: <https://www.eenews.net/articles/texas-advances-major-grid-rules-for-data-centers/>

1 **Q. What do you recommend the Commission do to mitigate the risk of cascading**
2 **breaker trips?**

3 A. I recommend that the Commission take action to have the reliability and interconnect
4 standards reviewed for this emerging risk, by whatever means it deems most effective and
5 expeditious. It would be prudent to have a recommendation in place before the Oracle 1.4
6 GW data center in Saline Twp. comes fully online.

7 **B. Dirty Power**

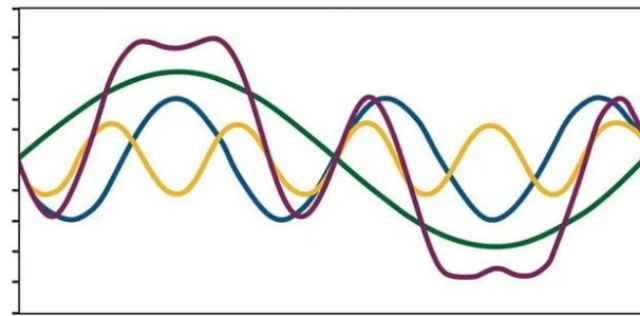
8 **Q. What risk do data centers pose to power quality?**

9 A. The grid operates on a 60 Hz sine wave. That means that the voltage cycle repeats 60 times
10 each second, or every 16.7 milli-seconds. Because data center load can vary widely in
11 much less time than a full cycle, it can distort the shape of that sine wave; not just in the
12 data center, but out into the surrounding area through the data center's interconnection.
13 The President of Embedded and Critical Power explains what harmonics are with an
14 illustration:

15 "Generally, voltage follows a rolling wave characterized by the smooth,
16 periodic oscillations — a sine wave, as depicted by the green line in
17 Figure 1. International standards for steady state loads established in the
18 mid-1990s governing harmonic currents, voltage flicker and other factors
19 have served data center operators well. Some have even established
20 additional, more stringent standards for their own facilities.

21 But AI models cause massive, sudden surges in power usage, making
22 "white space" within a data center — the room housing IT equipment such
23 as servers, storage, and networking gear — the source of distortion.
24 Drawing power in rapid, uneven bursts generates harmonics that distort
25 the voltage wave (the blue and yellow lines)."⁵⁸

⁵⁸ Christopher Butler, "Power quality: The unseen phenomenon behind some of the biggest data center challenges," *Flex.com*, September 22, 2025. Accessed on 6/2/26 at: <https://flex.com/resources/power-quality-the-unseen-phenomenon-behind-some-of-the-biggest->



Caption:
 ■ nonsinusoidal waveform
 ■ first harmonic (fundamental)
 ■ third harmonic
 ■ fifth harmonic

Figure 1. Harmonic distortion.

He recommends, “Adhering to utility interconnection standards such as IEEE 519 (U.S.)”⁵⁹

Q. Is there any evidence that data centers are commonly pushing harmonics out into the grid today?

A. Yes. Whisker Labs has installed hundreds of thousands of power quality monitors in American homes, including mine. Bloomberg did a study of the data from about one million Whisker monitors, and found a compelling correlation between homes with dirty power and areas of large-scale data center operation. “The report contends that harmonic issues will likely worsen without *significant investment* in grid infrastructure.”⁶⁰ (emphasis added)

[data-center-challenges](#)

⁵⁹ Ibid

⁶⁰ Zachary Skidmore, “AI data centers causing ‘distortions’ in US power grid – Bloomberg,” *Data Center Dynamics*, January 6, 2025. Accessed on 6/2/26 at:

1 **Q. Are harmonics fed back into the grid by large energy customers a new problem?**

2 A. No, this is a common problem with certain industrial equipment, but data centers give a
3 whole new scale to the problem.

4 **Q. What do you recommend the Commission do to mitigate the risk of cascading**
5 **breaker trips?**

6 A. I recommend that the Commission take action to have the interconnect standards reviewed
7 for the risk of harmonics on a new massive scale, by whatever means it deems most effect
8 and expeditious. It would be prudent to have a recommendation in place before the 1.4 GW
9 data center in Saline Twp. comes fully online.

<https://www.datacenterdynamics.com/en/news/ai-data-centers-causing-distortions-in-us-power-grid-bloomberg/>

1 **C. Risk to the Renewable Energy Standard**

2 **Q. Why do you think that the dramatic load increase driven by data centers poses a risk**
3 **to DTE’s continued compliance with the Renewable Energy Standard (MCL**
4 **460.1028)?**

5 A. More data center load creates two effects that are additive in their impact. Firstly, more
6 energy sales increase the amount of renewable energy needed, per the formula in MCL
7 460.1028(2). Secondly, data centers are apt to join the Voluntary Green Pricing (VGP)
8 program to increase their supply of renewable energy to 90% (to qualify for the Michigan
9 tax exemption) or to 100% (because they have corporate green energy objectives). The
10 proposed contracts with Google LLC are an example of the latter, as they will move the
11 data center to 100% green power via a VGP special contract “once the Company hits the
12 60% RPS target.”⁶¹

13 **Q. In response to the increase in demand for renewable energy, can’t DTEE just raise**
14 **capital and acquire more renewable energy generation?**

15 A. Yes, to a degree. But it is not possible to build unlimited amounts of renewable generation
16 in a few years. In its last Integrated Resource Plan (IRP) case, DTEE set a limit of adding
17 no more than 1,000 MW/year of solar and wind generation in 2026 and beyond in its
18 modeling, providing this justification for the limitation:

⁶¹ Direct testimony of K. L. Bilyeu, p KLB-9, lines 9-10

1 “Experience has shown that delays in the MISO interconnection queue,
2 recent RFP results, supply chain and labor market constraints, and local
3 opposition can limit the amount of renewable energy that can be built at
4 any given time. By placing a reasonable limit on the amount of MW of
5 renewable energy that can be built on an annual basis, the Company can
6 help ensure that modeling results are reflective of what is feasible to
7 implement.”⁶²

8 **Q. Will data center load drive DTEE to exceed 1,000 MW of additional renewable**
9 **generation per year?**

10 A. Yes. In the last IRP, DTEE’s Proposed Course of Action (PCA) called for added 3,600
11 MW of solar and 1,000 MW of wind between 2028 and 2032 (five years). That’s an
12 average of $(3,600 \text{ MW} + 1,000 \text{ MW}) / 5 \text{ years} = 920 \text{ MW/year}$; close to their self-
13 proclaimed 1,000 MW limit. This application, for Google’s 1 GW data center, calls for
14 renewable energy builds of 1,600 MW, scheduled as: “up to 500 MW by 2030, 700 MW
15 by 2031, and 400 MW by 2032.”⁶³ Clearly the IRP’s PSA plus this proposed build will
16 exceed the Company’s self-declared limit of 1,000 MW of new renewables per year in
17 2030 and 2031. The contract with the Green Chile Ventures LLC data center in Saline
18 Twp. will add significantly to these totals, as will other VGP customer growth and general
19 load growth.

⁶² U-21193, 5 Tr 1049, lines 15-20

⁶³ Direct testimony of K. L. Bilyeu, p KLB-14, line 13

1 **Q. What action do you recommend that the Commission take?**

2 A. In the Company's next REP case, the Commission should firmly warn the Company that
3 any future application for an extension to the deadline will only be approved if the
4 Company has shown that it has taken *every* reasonable and prudent measure to meet the
5 RPS mandate.

6 **D. Supply Chain Impacts**

7 5. **Q. Why do you think that the combined load of data centers in MISO and the**
8 **entire US will cause scarcity pricing, driving up utility costs and other customer's**
9 **rates indirectly?**

10 A. I will discuss two distinct indirect ways in which the combined loads of data centers can
11 increase rates indirectly:

- 12 1. Increasing the wholesale cost of both capacity and energy in MISO auctions.
13 2. Increasing the cost of network equipment due to demand exceeding supply.

1 **Q. Why do you think that data center load will increase the wholesale cost of both**
2 **capacity and energy in MISO auctions?**

3 A. Earlier in my testimony, I discussed how data centers have *caused* an increase in the price
4 of both wholesale capacity and energy in the PJM markets by creating scarcity. If we
5 consider large load customers (> 100 MW) as a customer class, that class is causing price
6 increases. I assert that the principle of cost causation requires that this hypothetical large
7 load class pay those increased costs; otherwise, other customers will be subsidizing the
8 data center customers, which are some of the wealthiest companies in the world. DTEE
9 itself appears to support this assertion (at least for one customer), stating: “the customer
10 will be subject... to a rate schedule approved by the Commission, and one that is *not cross*
11 *subsidized by any other customer class*.⁶⁴ The Commission also supported my general
12 assertion regarding the importance of avoiding cross-subsidies:

13 “Additionally, as demonstrated by MNSC and un rebutted by Consumers,
14 the addition of a 500 MW PPA to serve a large load customer causes a
15 9.1% increase to residential rates if existing cost of service principles are
16 followed. MNSC’s initial brief, p. 33; see also, 3 Tr 199-202. *This is*
17 *unacceptable. A core tenet of ratemaking is that customers are responsible*
18 *for the costs they impose on the system and the costs required to serve*
19 *them. Residential, commercial, and other industrial customers should not*
20 *have to pay for investments driven solely by large load additions.*”⁶⁵
21 (emphasis added)

22 **Q. Have there been studies on how increased data center load impacts the electric rates**
23 **of other customers?**

24 A. Yes, many. Bloomberg did a detailed assessment of the impact of data centers on

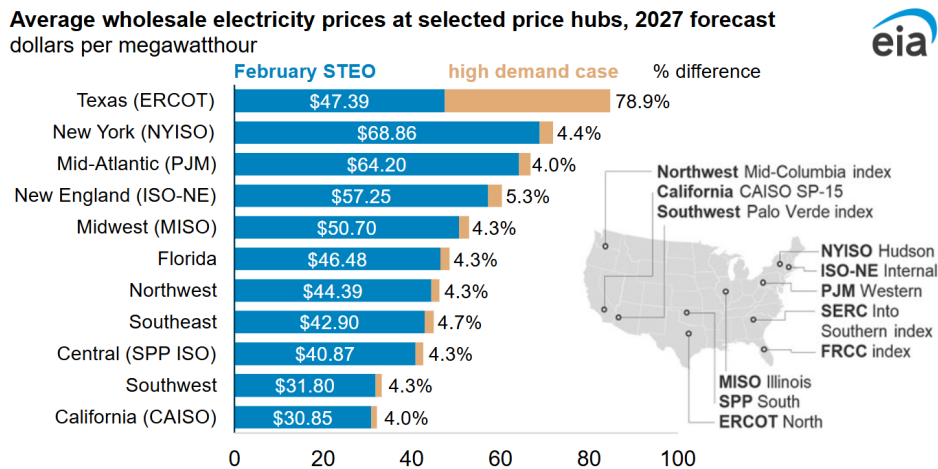
⁶⁴ U-21990, Commission order dated December 18, 2025, p 5, citing testimony of DTEE witness Neal T. Foley

⁶⁵ U-21859, Commission order dated November 6, 2025, p 116

wholesale electric prices in the US. While I don't have access to the full study, the publicly available summary is telling:

"The power needs of the massive complexes are rapidly driving up electricity bills... A Bloomberg News analysis of wholesale electricity prices for tens of thousands of locations across the country reveals the effects of the AP boom on the power market with unprecedented granularity... electricity now costs as much as 267% more for a single month than it did five years ago in areas located near significant data center activity."⁶⁶

An EIA study forecasts that wholesale rates in ERCOT (Texas) will go up 79% by 2027, due to dramatic load growth:⁶⁷



Data source: U.S. Energy Information Administration, *Short-Term Energy Outlook* (STEO), February 2026, and UPLAN[®] Network Power Model

Q. Have there been studies on the effect of data centers on retail rates?

A. Yes. Harvard Law School published a study looking at how the costs of serving data centers get passed on to other ratepayers via the rate case process. It asserts that the

⁶⁶ Josh Saul, Leonardo Nicoletti, Demetrios Pogkas, Dina Bass, and Naureen Malik, "AI Data Centers are Sending Power Bills Soaring," September 29, 2025. Accessed on 6/3/26 at: <https://www.bloomberg.com/graphics/2025-ai-data-centers-electricity-prices/>

⁶⁷ EIA, "Fossil generation could rise with faster-than-expected growth in data center power demand," March 12, 2026. Accessed on 6/3/26 at: <https://www.eia.gov/todayinenergy/detail.php?id=67344>

conventional regulatory approach will result in cross subsidies:

“If PUCs allow utilities to follow the conventional approach of socializing system expansion, utilities will impose data centers’ energy costs on the public. The easiest way for utilities to shift data centers’ energy costs to the public is to simply follow long-standing practices in rate cases.”⁶⁸

Q. Did the Harvard Law School study make any recommendations?

A. Yes. It recommended:⁶⁹

1. Establishing robust guidelines for reviewing special contracts.
2. Requiring data centers to take service under tariffs (vs. special contracts).
3. Amending State law to require retail competition and allow for “energy parks.”
4. Requiring utilities to disclose data center forecasts.
5. Allowing new data centers to take service only if they commit to flexible operations.

Q. In addition to the impact of data center load on wholesale capacity and energy prices, in what other ways can data centers increase other ratepayers’ rates indirectly?

A. The rapid load growth driven by data centers is causing the construction of huge amounts of additional generating capacity. Orders for gas-fired generation tripled in 2025.⁷⁰

⁶⁸ Eliza Martin and Ari Peskoe, “Extracting Profits from the Public: How Utility Ratepayers Are Paying for Big Tech’s Power,” *Harvard Law School*, p 10. Accessed on 4/30/26 at: <https://eelp.law.harvard.edu/wp-content/uploads/2025/03/Harvard-ELI-Extracting-Profits-from-the-Public.pdf>

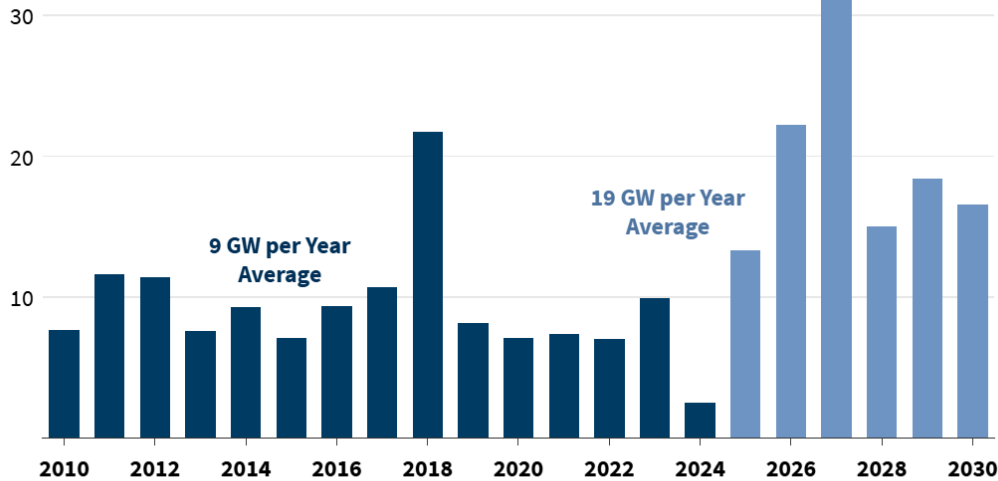
⁶⁹ Ibid, p 3 (Table of Contents, section III)

⁷⁰ Brandon Vigliarolo, “AI datacenter boom triples US gas power builds, filling the air with more CO2,” *The Register*, January 29, 2026. Accessed on 6/4/26 at: <https://www.theregister.com/software/2026/01/29/us-gas-power-projects-tripled-in-2025-on-ai-demand/4388904>

Demand is expected to increase dramatically this year and in 2027:⁷¹

US gas-fired generation capacity additions (GW)

■ Historical Build Rate ■ Forecast Build Rate



Source: Preliminary Monthly Electric Generator Inventory (EIA, Mar 2025); Gas Plants, Pipelines, and Export Terminals (Sierra Club, Apr 2025)

This demand surge has caused order backlogs and price increases in critical power system components:

“There are effectively only three relevant manufacturers that can produce large-scale gas turbines: GE Vernova (\$162B market cap), Siemens Energy (\$91B), and Mitsubishi Heavy Industries (\$84B). These machines sit at the center of the modern power plant. They are the hardware that converts fuel into motion and motion into electrons. Today, they are booked solid for years. GE, Siemens, and Mitsubishi are each reporting order backlogs that stretch roughly five years, with many delivery slots already sold into the next decade.”⁷²

⁷¹ Jesse Cohen, Tyler Fitch, Lauren Shwisberg, “Gas Turbine Supply Constraints Threaten Grid Reliability; More Affordable Near-Term Solutions Can Help,” Rocky Mountain Institute, June 18, 2025. Accessed on 6/4/26 at: <https://rmi.org/gas-turbine-supply-constraints-threaten-grid-reliability-more-affordable-near-term-solutions-can-help/>

⁷² Zach Fredericks, “The gas turbine bottleneck reshaping energy infrastructure Electricity costs are rising fast, and the hardware to generate more power is suddenly scarce,” February 10, 2026. Accessed on 6/4/26 at: <https://www.primary.vc/articles/the-gas-turbine-bottleneck-reshaping-energy-infrastructure-ex8qe>

1 High demand and limited manufacturing capacity have driven up the cost of building
 2 CCGT plant. According to the CEO of Next Era, from 2022 to 2025, the price to build a
 3 CCGT price tripled, from \$785/kW to 2,400/kW.⁷³ That's not a hypothetical number or the
 4 results of a study; it's *history*. In January, GE Vernova, one of the world's largest
 5 manufacturers of gas turbines reported that they're booking orders for gas-fired plants at
 6 \$2,500/kW, with prices "still rising."⁷⁴ In 2025, utilities reported that GE Vernova was
 7 charging them a \$25M reservation fee to accept orders.⁷⁵

8 **Q. Are order backlogs and surging prices limited to gas turbines?**

9 A. No, electrical transformers also exhibit order backlogs and rapid price increases:

10 "The U.S. is grappling with a severe transformer shortage, disrupting
 11 infrastructure projects and driving up costs. Lead times for power
 12 transformers have surged from 30–60 weeks pre-pandemic to as long as 4
 13 years, with prices increasing 60%–80% since 2020."⁷⁶

⁷³ Nicholas Cunningham, Costs to build gas plants triple, says CEO of NextEra Energy," *Gas Outlook*, March 3, 2025. Accessed on 6/2/26 at: <https://gasoutlook.com/analysis/costs-to-build-gas-plants-triple-says-ceo-of-nextera-energy/>

⁷⁴ Brian Martucci, "GE Vernova Q4 gas turbine orders surge 74%," *Utility Dive*, January 20, 2026. Accessed on 6/4/26 at: <https://www.utilitydive.com/news/ge-vernova-gas-turbine-orders-offshore-wind-earnings/810974/>

⁷⁵ Grid Lab, "The new reality of power generation," September 2025, p 2. Accessed on 6/4/25 at: <https://www.utilitydive.com/news/ge-vernova-gas-turbine-orders-offshore-wind-earnings/810974/>

⁷⁶ Electrical Trader, "Transformer Shortages: Supply Chain Impact on Pricing," February 2, 2026. Accessed on 6/4/26 at: <https://electricaltrader.com/blogs/news/transformer-shortages-supply-chain-impact-pricing>

This table provides a nice summary of the supply chain problem:⁷⁷

Power Transformer Lead Time Data: Current Benchmarks

Equipment Type	Average Lead Time	Price Change Since 2019	Demand Growth Since 2019
Power transformers	128 weeks	+77%	+119%
Generator step-up transformers	144 weeks	+45%	+274%
Distribution transformers	Extended but shorter	+78% to +95%	+34%
Medium-voltage switchgear	Extended	+50%	Significant

Q. Doesn't the rate-making process, and the protections in the contracts protect other ratepayers from data-center induced costs?

A. No, at least not fully. Wood MacKenzie studied 20 large power users. "In almost all of those cases, the firm found, the money that large energy users paid to electric utilities would not be enough to cover the cost of the equipment needed to serve them. The rest of the costs would be borne by other utility customers or the utility itself."⁷⁸ Ben Hertz-Shargel, the global head of grid edge research for Wood MacKenzie explained it this way:

⁷⁷ Wes Garrett, "Power Transformer Lead Times Hit Record Highs as U.S. Grid Equipment Shortage Deepens," *Industrial Sage*, May 6, 2026. Accessed on 6/4/26 at: <https://www.industrialsage.com/power-transformer-lead-times-us-grid-shortage/>

⁷⁸ Ivan Penn, "Data Centers' Hunger for Energy Could Raise All Electric Bills," *The New York Times*, May 16, 2025. Accessed on 6/4/26 at: <https://www.nytimes.com/2025/05/16/business/energy-environment/data-centers-utilities-electricity-bills.html>

1 “The policies that states and utilities have put in place will significantly
2 reduce risks of spreading the costs of improvements for the large-load
3 customers, but ‘they do not provide complete protection,’ Mr. Hertz-
4 Shargel said. ‘Only by removing data-center-caused infrastructure from
5 utilities books, such as by allowing large loads to contract with third
6 parties for generation via clean transition tariffs, are both ratepayers and
7 utility shareholders fully protected.’ ”⁷⁹

8 **Q. How will these equipment price increases affect Michigan ratepayers?**

9 A. Both DTEE and Consumers Energy have announced that they will be proposing new
10 natural-gas fired plants in the IRPs they will be filing this year. The new gas plants that
11 DTEE and Consumers will be proposing will cost more than they would have if Michigan
12 was the only State building data centers. Transformer price increases will affect costs
13 regardless of the type of generation being built. Demand across the country, and the world,
14 has caused these price increases. The cost impact of data centers as a group is different
15 than the cost impact of any particular data center. We must not become so fixated on each
16 data center “tree” that we fail to notice the data center “forest.”

⁷⁹ Ibid

1 **Q. Would it be fair for data center companies in Michigan pay costs caused by data**
2 **center companies across the country?**

3 A. There are only four or five companies responsible for the commissioning of most of the
4 data center capacity being built in the US. The list of parent-company customers in my
5 hypothetical large-load customer class is very short. Consider the alternative: would it be
6 fair that Michigan's residential customers pay for costs caused by data center companies
7 across the country? No, I don't think so; that would violate the principle of cost causation.
8 Someone is going to pay for the cost impacts of the whole data center "forest"; the
9 Commission's decisions will determine who will pay. The costs should be paid by the
10 companies causing the costs, regardless of geography.

11 **Q. What action do you recommend the Commission take to protect ratepayers from the**
12 **cost of data center driven scarcity pricing?**

13 A. Thus far, the Commission's orders on data centers have focused on preventing costs from
14 stranded resources being passed on to other customers. Thus far, the Commission has
15 directed that data center customers use existing tariffs, subject to review in two concurrent
16 rate cases (U-22046 and U-22070). But cost-of-service studies and standard cost
17 allocations will not protect other ratepayers from the *indirect* costs caused by data center
18 demand driving up the prices of MISO energy and capacity, nor the increased prices of
19 power equipment. In those concurrent rate cases, and future rate cases, the Commission
20 should be open to imposing temporary "scarcity cost" fees on service to data center
21 customers, until the scarcity of supplies is resolved by market adjustments.

1 **Q. Should the Commission consider creating a new customer class for data center**
2 **customers?**

3 A. Yes, assigning data center customers to a separate customer class will naturally provide
4 reporting of the revenue paid by that class, without compromising the customer's
5 confidentiality. The establishment of a separate class for data centers would help to ensure
6 that cost allocations correctly assign direct and indirect costs associated with the data
7 center for purposes of the utility's cost of service studies to be presented in rate cases, and
8 can serve as an initial approach to prevent other customers from cross subsidizing the costs
9 caused by the data center. I will provide additional support for this proposal in the
10 concurrent rate cases (U-22046 and U-22070), where a more wholistic view will be
11 available for the Commission's consideration.

12 **VI. RECOMMENDATIONS**

13 **Q. What actions should the Commission take in this case?**

14 A. I offer the following recommendations:

- 15 1. The Commission's order should repeat the statement made in its U-21990 order,
16 warning DTEE that in the event of customer default, any unrecovered costs or
17 remaining liability will be borne by the Company, not other ratepayers.
- 18 2. The Commission's order should include reporting requirements, similar to those in U-
19 21990. In the concurrent rate cases, the Commission should consider a new customer
20 class for data center customers.
- 21 3. The Commission should deny DTEE's request to treat the so-called "FCM" on ZRCs
22 transferred from the customer to the Company as non-refundable income.

1 4. The Commission should order a study that reviews existing reliability and interconnect
2 standards, to recommend grid protections from cascading breaker trips resulting from
3 data centers switching off the grid in reaction to transient events on the grid.

4 5. The Commission should order a review of existing interconnect standards regarding
5 customer-induced grid harmonics and sub-harmonics, to ensure that they are adequate
6 for the scale of harmonics that data centers have been seen to produce elsewhere.

7 6. In the Company's next REP case, the Commission should firmly warn the Company
8 that any possible future application for an extension to the REP compliance deadline
9 will only be approved if the Company has shown that it has taken *every* reasonable and
10 prudent measure to meet the RPS mandate.

11 7. In concurrent and future rate cases, the Commission should be open to imposing a
12 temporary "scarcity pricing fee" on service to data center customers, until the scarcity
13 of supplies is resolved by market adjustments.

14 **Q. Does that conclude your testimony?**

15 **A. Yes.**

1 JUDGE STALEY: All right. And then we
2 will move on to MEC/NRDC/Sierra Club.

3 MS. HILLYER: Thank you, your Honor. At
4 this time, on behalf of the Michigan Environmental
5 Council, Natural Resources Defense Council, and Sierra
6 Club, I move to bind into the record the prefiled Direct
7 Testimony of Bryndis A. Woods, which consists of a cover
8 page, table of contents, and 39 pages of questions and
9 answers. I also move for the admission of Dr. Woods'
10 exhibits, which consist of Exhibits MEC-1 through MEC-15;
11 and pursuant to an agreement with the Company, in lieu of
12 cross-examination of certain Company witnesses, I also
13 move to admit Exhibits MEC-35 through MEC-49, which
14 consists of the Company's responses to certain discovery
15 requests which were uploaded to the hearing's SharePoint
16 for the parties to review.

17 JUDGE STALEY: All right. Is there any
18 objection to the binding in of the prefiled Direct
19 Testimony of Bryndis A. Woods, along with the admission
20 of Exhibits MEC-1 through MEC-15, as well as MEC-35
21 through MEC-49?

22 Hearing none, the prefiled Direct
23 Testimony of Bryndis A. Woods is bound into the record,
24 and Exhibits MEC-1 through MEC-15 are admitted into
25 evidence, and MEC-35 through MEC-49 are also admitted

1 into evidence.

2 (Direct Testimony bound in.)

3 - - -

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of
DTE ELECTRIC COMPANY for Approval
of Special Contracts and for other relief.

Case No. U-22058

DIRECT TESTIMONY OF BRYNDIS A. WOODS**ON BEHALF OF**

**MICHIGAN ENVIRONMENTAL COUNCIL,
NATURAL RESOURCES DEFENSE COUNCIL,
AND SIERRA CLUB**

June 5, 2026

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I. INTRODUCTION & QUALIFICATIONS

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

A. My name is Bryndis Woods. I am a Principal Analyst at the Applied Economics Clinic (“AEC”). The business address is 6 Liberty Square, PMB 98162, Boston, Massachusetts, 02109.

Q. On whose behalf is this testimony being offered?

A. I am testifying on behalf of Michigan Environmental Council, Natural Resources Defense Council, and Sierra Club (collectively, MNS).

Q. Please summarize your experience in the field of utility regulation.

A. I have worked in my role at AEC for nine years. At AEC, I focus on energy and climate issues, including renewable energy and climate planning, decarbonization strategies, energy efficiency, and environmental justice. I have provided testimony and expert comments in Massachusetts, New York, Texas, and Virginia. I have provided expert analysis for many public-interest clients including, but not limited to: the Massachusetts Department of Energy Resources, Western Organization of Resource Councils, Just Transition Northwest Indiana, Clean Energy Group, Illinois Cannabis Regulation Oversight Office, The Nature Conservancy, the State of Rhode Island Department of Environmental Management, Clean Virginia, Connecticut Office of Consumer Counsel, Environmental Defense Fund, Massachusetts Climate Action Network, City of Cambridge Massachusetts, The Office of the People’s Counsel for the District of Columbia, American Council for an Energy-Efficient Economy, New York Lawyers for the Public Interest, Earthjustice, Maine Governor’s Energy Office, Conservation Law Foundation, Green

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Energy Consumers Alliance, and Alliance for Affordable Energy. My full work experience is summarized in my CV, provided as Exhibit MEC-1.

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

A. I have not previously testified before the Michigan Public Service Commission (“Commission”). I have testified before other state utility commissions in the following cases:

- **Public Utility Commission of Texas, Docket No. 58664:** Application of Southwestern Public Service Company to Amend its Certificate of Convenience and Public Necessity to Construct Generation Resources and Associated Facilities in Texas and New Mexico; For Good-Cause Exceptions; And For Related Relief;
- **Commonwealth of Virginia State Corporation Commission, Case No. PUR-2023-00066:** Virginia Electric & Power Company’s Integrated Resource Plan filing;
- **Massachusetts Department of Public Utilities and Energy Facilities Siting Board, Docket Nos. EFSB 14-04/D.P.U. 14-153/14-154:** Project Change request by NSTAR Electric Company d/b/a Eversource Energy.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

Exhibit MEC-1	CV of Bryndis Woods
Exhibit MEC-2	Company Response to U-22058-MNS 1.2b & d
Exhibit MEC-3	Company Response to U-22058-CEOMEIBCIEIDE 1.20b & 1.21b

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1	Exhibit MEC-4	Company Response to U-22058-MNS 1.11
2	Exhibit MEC-5	Company Response to U-22058-MNS 2.5c
3	Exhibit MEC-6	Company Response to U-22058-MNS 2.15a
4	Exhibit MEC-7	Company Response to U-22058-MNS 1.4a
5	Exhibit MEC-8	Company Response to U-22058-MNS 2.10a
6	Exhibit MEC-9	Company Response to U-22058-MNS 2.12b
7	Exhibit MEC-10	Company Response to U-22058-MNS-1.13a
8	Exhibit MEC-11	Company Response to U-22058-MNS 3.14
9	Exhibit MEC-12	Company Response to U-22058-CEOMEIBCIEIDE 1.41a
10	Exhibit MEC-13	Company Response to U-22058-MNS 2.14a
11	Exhibit MEC-14	Company Response to U-22058-MNS 1.12a
12	Exhibit MEC-15	Company Response to U-22058-MNS 3.13

13 **II. SUMMARY**

14 **Q. Please briefly summarize DTE Electric Company's requests in this proceeding.**

15 **A.** DTE Electric Company ("DTE" or "the Company") is requesting the Commission to grant
16 expedited approval of the Company's Primary Supply Agreement ("PSA") and Clean
17 Capacity Accelerator Agreement ("CCAA") (collectively, the "Special Contracts") with
18 Google LLC ("the Customer") that would become effective upon Commission approval.
19 The Company is proposing the Special Contracts to serve the Customer's planned 1.0
20 gigawatt ("GW") data center facility in Van Buren Township, Michigan, which is
21 scheduled to "begin taking service in December 2027 with max load being achieved by

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1 December 2028.”¹ The Company maintains that the Special Contracts “establish a
2 balanced and protective framework that includes appropriate safeguards and minimizes the
3 risks associated with serving large load customers [and] reflects a reasonable and prudent
4 balance between the advantages of serving a new large load customer and protecting
5 existing customers from risk and potential cost subsidies.”²

6 The Company’s Application notes that the CCAA sets forth obligations related to “the
7 development and cost recovery of up to 480 megawatts (MW) of energy storage projects,
8 up to 1,600 MW of renewable energy projects, and the transfer of 300 MW of zonal
9 resource credits (“ZRCs”).”³ The 480 MW of energy storage projects will include 55 MW
10 of long duration storage, and the Customer will pay the costs of all storage projects over
11 their 15-year economic lifetime. The 300 MW of ZRCs will be obtained by the Customer
12 and transferred to the Company “for each MISO season beginning June 1, 2028 until May
13 31, 2033.”⁴ Finally, the Customer requests that DTE develop “up to 1,600 MW of
14 renewable energy projects.”⁵ The Company claims that “Commission approval of the
15 Special Contracts will not impact existing rates or increase the Company’s cost of service
16 for existing customers.”⁶

¹ Application of DTE ELECTRIC COMPANY for Approval of Special Contracts and for other relief. MPSC Case No. U-22058, p 2.

² Ibid.

³ Ibid at. 3.

⁴ Ibid.

⁵ Ibid.

⁶ Ibid. at 5.

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1 **Q. What topics are you addressing in your testimony?**

2 **A.** My testimony focuses on the Company's proposed renewable energy and energy storage
3 buildouts, and issues with the Company's customer benefit analysis, and provides
4 recommendations to help ensure that the Company meets (1) its renewable energy and
5 energy storage capacity goals consistent with utility planning best practices and (2) its
6 Renewable Portfolio Standard ("RPS") obligations. My testimony also recommends that
7 certain issues should not be decided in this case, such as cost allocations or resource
8 predeterminations. I address the following topics:

9 • **The Company's benefit estimate is preliminary and subject to change:** The Company's
10 customer benefit analysis is based on hypothetical resources, and the expedited nature of
11 this proceeding has limited the opportunity for robust, independent, third-party expert
12 review of the Company's purported customer costs and benefits. An integrated resource
13 plan ("IRP") proceeding is where the utility generation investments needed to serve the
14 Customer would be decided, while a rate case is the appropriate venue to review the
15 Company's cost-benefit estimates, the cost allocation and rate design decisions underlying
16 those estimates, establish a revenue requirement for the generation investments, and
17 establish just and reasonable rates on that basis. The Company plans to allocate costs
18 associated with its planned generation resources in rate case and PSCR plan and
19 reconciliation filings, so all cost allocations related to the Company's proposed resources
20 should be addressed in those venues and not in a stand-alone contract approval docket that
21 does not propose any specific resources or provide adequate opportunity for robust third-
22 party expert review of the Company's cost estimates.

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- 1 • **The Company's distribution cost estimate leaves little room for cost escalation**
2 **pressures:** The Company's distribution cost range estimate leaves just a \$5.7 million
3 buffer for potential unforeseen costs or cost escalation before DTE non-data center
4 ratepayers start to foot the bill for distribution costs stemming from service of the
5 Customer's load. The Company uses current pricing (instead of appropriate price forecasts)
6 to develop its estimates in an economic context where significant inflationary pressures are
7 at play, both in the economy at large and in the energy sector in particular.
- 8 • **Specific proposed resources that the Customer is not committing to pay for should be**
9 **identified in the Company's IRP process and not in this proceeding:** Consistent with
10 best practice, the Company plans to develop a specific resource portfolio in its upcoming
11 IRP filing. I agree with this approach and disagree with the Company's decision to discuss
12 various purported benefits of the CCGT plus CCS resource in this proceeding given that
13 there is not a specific proposal for this resource, but rather it is only a hypothetical, proxy
14 resource utilized for modeling purposes. I urge the Company to adopt best practices as they
15 relate to IRPs to ensure the development of an optimized, least-cost resource portfolio.
- 16 • **The Commission should disregard information about benefits associated with the**
17 **Company's proxy resource constructed for modeling purposes:** In this proceeding, the
18 Company assumes the existence of a proxy CCGT plus CCS resource that was developed
19 for the singular purpose of performing the Company's customer benefit analysis covering
20 the years 2028 to 2041 as provided in the Direct Testimony of Aaron Willis and Exhibit
21 A-19. The Commission should disregard all information DTE has provided regarding the
22 various purported benefits of the CCGT plus CCS resource given that no specific resources

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are being proposed in this proceeding and any information about the benefits of a proxy resource is irrelevant.

- **The Company should be required to deploy (and the Customer pay for) the full planned amount of renewable and storage resource capacity (i.e., 1,600 MW and 480 MW, respectively):** The “up to” provision in the Company’s renewable energy and energy storage resource goals all but ensures that the Company will fall short of deploying 1,600 MW of renewable energy and 480 MW of energy storage resources by establishing a ceiling as opposed to a floor. I urge the Commission to condition its approval of the Special Contracts on the requirement that the Company deploy (and the Customer pay for) the full planned amount of renewable and storage resource capacity to ensure that the 1,600 MW and 480 MW goals are achieved.
- **Under-achieving the renewable energy goal would impact the Company’s RPS obligations:** The Company is estimating its RPS compliance assuming that 1,600 MW of renewable energy resources are developed under the CCAA—falling short of that target would increase the Company’s RPS compliance obligations and draw down the Company’s REC surplus.
- **Recommendations to help the Company reach its renewable energy and energy storage goals:** The Company has failed to provide detailed information demonstrating that it can reach the renewable energy and energy storage goals as defined, and the conditions the Company lists as potential scenarios under which the Company may fail to reach its targets are exceedingly common. The Company should develop specific commitments that will help ensure it meets its renewable energy resource and energy storage resource deployment goals, including: issuing Requests for Proposals (“RFPs”) that seek more

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renewable energy and energy storage resources than the proposed annual build amounts; pursuing behind-the-meter and distributed energy resources as part of its renewable energy and energy storage goals; conducting analyses of the feasibility of its renewable energy and energy storage plans; and making specific commitments regarding how the Company will respond to potential deployment barriers (i.e. supply chain shortages, permitting constraints, MISO queue constraints).

- **Issues with the Company's RPS compliance analysis approach:** The Company's RPS compliance assessment has various issues, including an assumption of renewable energy capacity amounts that are uncertain; a calculation error that changes the Company's status in 2032 from RPS compliance to noncompliance; and REC surplus forecasts that are not aligned with historical trends. I recommend that the Commission require the Company to reconduct its RPS compliance assessment in its forthcoming Renewable Energy Plan ("REP") and also require the Company to identify the amount of capacity that would be required in each year to achieve RPS compliance (rather than assume uncertain renewable energy capacity amounts) and set forth a clear plan for bringing online at least that amount of renewable capacity in each year.

Q. Which Company witnesses' testimony do you discuss in your testimony?

A. I am addressing the testimony of Company witnesses Neal T. Foley, Aaron Willis, Steven N. Benyard, Shawn D. Burgdorf, and Kevin L. Bilyeu.

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III. THE COMPANY’S BENEFIT ESTIMATE IS PRELIMINARY AND SUBJECT TO CHANGE, AND THE COMPANY’S DISTRIBUTION COST ESTIMATE LEAVES LITTLE ROOM FOR COST ESCALATION PRESSURES

Q. Please summarize this section.

A. In this section, I review the Company’s approach to estimating the costs and benefits of the Special Contracts, including the Company’s distribution cost range estimate specifically. I demonstrate that: the Company’s customer benefit analysis is based on hypothetical resources; this proceeding does not provide an opportunity for robust independent, third-party expert review of the Company’s estimated customer costs and benefits; and various cost-related issues remain to be fully litigated in a rate case proceeding, which is the appropriate venue to review the Company’s cost-benefit estimates and its proposed utility investments and expenses, establish a revenue requirement, and establish just and reasonable rates on that basis. I urge the Commission to not predetermine or accept that the Special Contracts will result in \$1.7 billion in customer benefits as the Company claims—there are too many unknowns. Regarding the Company’s distribution cost range estimate, I demonstrate that it leaves just a \$5.7 million buffer for potential unforeseen costs or cost escalation before DTE non-data center ratepayers start to foot the bill for distribution costs directly related to serving the Customer’s load.

Q. What does the Company state regarding recovery of costs related to the proposed renewable energy and energy storage resources?

A. The Company notes that it “envisions combined revenues and avoided costs will be presented in general rate case filings and PSCR plan and reconciliation filings.”⁷ I agree

⁷ Ex MEC-2, Company Response to U-22058-MNS 1.2b & d.

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1 with this approach and emphasize the importance that all resource cost allocation decisions
2 be made in their appropriate venue, a rate case.⁸ A rate case is the only appropriate venue
3 to review the Company's cost-benefit estimates and its proposed utility investments and
4 expenses, establish a revenue requirement, and establish just and reasonable rates on that
5 basis. As discussed in greater detail below, the Company makes various cost-related
6 assumptions in the current proceeding for the purpose of developing a customer benefit
7 analysis.

8 **Q. Is the Company proposing any specific resource projects in this proceeding?**

9 **A.** No, with the exception of the renewable and storage resources covered under the CCAA,
10 the Company is not proposing any specific generation resources in this proceeding, and
11 notes that it plans to develop a specific resource portfolio in its upcoming IRP filing.
12 However, while the Company is not proposing any specific generation resources in this
13 proceeding, it is using a proxy combined cycle gas turbine ("CCGT") with carbon capture
14 and storage ("CCS") technology to conduct its customer benefit analysis (as described in
15 more detail below).

16 **Q. On what basis is the Company providing estimated customer benefits associated with**
17 **the Special Contracts?**

18 **A.** The Company conducted a customer benefit analysis that claims DTE's non-data center
19 customers will "realize a benefit of approximately \$1.7 billion during the term of the

⁸ NARUC. N.d. NARUC Desk Reference Manual. "3. Ratemaking Fundamentals and Principles". Available at: <https://www.naruc.org/commissioners-desk-reference-manual/3-ratemaking-fundamentals-and-principles/>. (accessed June 4, 2026).

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Contracts”⁹ and that “the combined revenues and avoided costs exceed the costs cause by the Customer over the term of the contract.”¹⁰ Figure 1 below shows the Company’s cost/benefit breakdown by component:

Figure 1. Total costs and benefits by component (reproduced from Willis Direct)

• Base Sales Benefit	\$4.85B benefit
• PSCR ³	\$2.31B benefit
• Other Non-F&PP O&M	\$0.02B cost
• Proxy CCGT	\$4.17B cost
• CCS direct cost	\$2.43B cost
• <u>Storage Pull Ahead</u>	<u>\$1.16B benefit</u>
• Total	\$1.70B benefit

Q. Is this proceeding intended to litigate the costs and benefits of the resources proposed in the Company’s Special Contracts?

A. No. As discussed on page 5 above, actual utility investment decisions will be made during resource planning, and cost allocation are issues that will be addressed in a rate case proceeding. The Company acknowledges that “Base Sales Benefit” as shown in Figure 1 above—its largest estimated benefit to DTE customers—is an item “typically addressed in an electric rate case.”¹²

⁹ Direct Testimony of Neal T. Foley, p 8, lines 18-19.

¹⁰ Direct Testimony of Aaron Willis, p 4, lines 21-22.

¹¹ Willis Direct, p 7, lines 15-21.

¹² Willis Direct, p 8, lines 7-8.

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1 **Q. What resource assumptions are included in the Company’s customer benefit**
2 **analysis?**

3 **A.** The Company’s customer benefit analysis is based on generic energy storage resources
4 totaling 480 MW of capacity (to calculate the “Benefit of Storage Pull Ahead” as shown in
5 Figure 1 above), but also a hypothetical proxy CCGT with CCS technology, as represented
6 in the “proxy CCGT” and “CCS direct cost” lines in Figure 1 above, which was developed
7 as “generic modeling construct” employed in the “context of analyzing resource adequacy
8 requirements solely for purposes of performing the customer benefit analysis” in this
9 proceeding.¹³

10 **Q. Has this proceeding provided an opportunity for robust independent, third-party**
11 **expert review of the Company’s estimated customer costs and benefits?**

12 **A.** No, this is an expedited proceeding to determine whether to approve the Company’s
13 Special Contracts and regarding the framework those Special Contracts establish to protect
14 existing customers from risk associated with serving the Customer by including appropriate
15 safeguards and minimizing risks. Due to the expedited nature of this proceeding and its
16 focus on the framework established by the Special Contracts, this proceeding has provided
17 limited opportunity for robust independent, third-party expert review of the Company’s
18 estimated customer costs and benefits, which—consistent with best practice—should be
19 addressed in a rate case proceeding.

¹³ Ex MEC-3, Company Response to U-22058-CEOMEIBCIEIDE 1.20b & 1.21b.

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1 **Q. Do any of the Company’s assumptions in its customer benefit analysis concern you?**

2 **A.** Yes, in its Base Sales Benefit calculation, the Company assumes that the Customer’s
3 “underlying load is at full ramp of 1000 MW and a 90% load factor,”¹⁴ which represents
4 an exceptionally efficient utilization. Publicly available information suggests that this level
5 of efficiency has not been realized among existing data centers in the United States. For
6 example, a 2025 study by Energy and Environmental Economics, Inc. (“E3”) that used
7 real-world data from a “major utility territory” determined that “only two data centers had
8 load factors above 90%...and fewer than half had load factors above 80%.”¹⁵ In addition,
9 Witness Foley’s testimony indicates that the Special Contracts establish a minimum billing
10 demand (“MBD”) of “80% of the contract capacity applicable for that billing period”¹⁶ (i.e.
11 80% of 1,000 MW, or 800 MW), which indicates that the Customer is under no obligation
12 to reach a 90% load factor as assumed in the Company’s benefit calculations. To be clear,
13 if the Customer’s load factor is less than 90%, the Company’s estimated Base Sales Benefit
14 will be larger than the actual benefit.

15 **Q. Should the Commission predetermine that the Special Contracts would result in the**
16 **Company’s claimed customer benefits of \$1.7 billion?**

17 **A.** No, I would urge the Commission not to predetermine that the Special Contracts will result
18 in the Company’s claimed costs or benefits for customers given that: 1) no specific resource
19 proposals yet exist and the modeling was conducted on the basis of various resource

¹⁴ Willis Direct, p 8, lines 9-10.

¹⁵ Bessasparis, S. et al. December 2025. “Forecasting Large Loads in the Age of AI and Data Centers.” Energy and Environmental Economics, Inc. (E3). Available at: https://www.ethree.com/wp-content/uploads/2025/12/E3Whitepaper_DataCenterForecasting.pdf. p 3.

¹⁶ Foley Direct, p 13.

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1 hypotheticals, 2) the expedited nature of this proceeding has limited the opportunity for
2 independent, third-party expert review, and 3) various cost related issues remain to be fully
3 litigated in a rate case proceeding.

4 **Q. Do you have any other concerns about potential customer cost allocations?**

5 **A.** Yes. Under the Line Extension Agreement, the Company notes that it “cannot directly
6 assign more than \$50 million of electric infrastructure costs to the Customer”¹⁷ and, as
7 such, would recover any distribution costs greater than \$50 million through base rates, i.e.
8 would pass those costs along to non-data center customers. The Company’s current cost
9 estimate is \$29.1 million to \$44.3 million, the range of which is “necessary to account for
10 cost variability associated with the different configuration options still under consideration
11 by the Customer.”¹⁸ Given the information provided by the Company regarding its current
12 distribution cost estimate, I am concerned that there is only \$5.7 million of headroom
13 between the top of the range and the Company’s own cap on infrastructure costs: the point
14 past which other customers will start to foot the bill. I recommend that the Commission
15 condition any approval of the Special Contracts on Google paying all electric infrastructure
16 costs required to connect Google’s data center without any cap and prohibit DTE from
17 recovering any of these costs from non-data center customers.

¹⁷ Ex MEC-4, Company Response to U-22058-MNS 1.11.

¹⁸ Ex MEC-4, Company Response to U-22058-MNS 1.11.

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1 **Q. What information has the Company provided regarding its current distribution cost**
2 **estimate?**

3 **A.** The Company developed its distribution cost estimate by including three categories of
4 costs: 1) materials, 2) total labor (both DTE and Contractors) and design, and 3) other.¹⁹
5 The Company said it used “current supplier pricing, historical purchase data, recent
6 contractor bid information, and established unit rates reflective of anticipated site
7 conditions” to develop the cost estimates.²⁰ However, Witness Benyard’s workpapers
8 supporting the cost estimate range do not include any calculations, analysis, or data
9 sources, only three rows of data which are hard-coded cost estimate ranges for each of the
10 three cost categories listed above.

11 **Q. Please summarize your concern as it relates to the Company’s distribution cost**
12 **estimate.**

13 **A.** My concern is that there is only \$5.7 million of headroom for potential unforeseen costs or
14 cost inflation—recall that the Company is using “current” pricing to develop its estimates
15 in an economic context where significant inflationary pressures are at play,²¹ including in
16 the energy sector specifically²²—before DTE non-data center ratepayers start to foot the

¹⁹ Workpapers SNB-1.

²⁰ Direct Testimony of Steven N. Benyard, p 6, lines 7-9.

²¹ See: Deloitte Global Economics Research Center, “Changing inflation dynamics pose new risks for the US economy” <https://www.deloitte.com/us/en/insights/topics/economy/spotlight/us-inflation-dynamics-effect-us-economy.html>. (accessed June 4, 2026).

²² See: CFC Solutions, “Transformers Are Facing Major Cost, Supply Chain Pressures” <https://www.nrucfc.coop/content/solutions/en/stories/energy-tech/transformers-are-facing-major-cost--supply-chain-pressures.html> (accessed June 4, 2026); and Utility Dive, “Utilities face cost-recovery risk as infrastructure costs, demand rise: Morningstar” <https://www.utilitydive.com/news/utilities-cost-recovery-risk-data-centers-rates/811446/>. (accessed June 4, 2026).

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1 bill for distribution costs directly related to serving the Customer's load.

2 **Q. Please summarize your recommendations for the Commission.**

3 **A.** I urge the Commission not to predetermine that the Special Contracts will result in the
4 Company's claimed costs or benefits for customers given that: 1) no specific resource
5 proposals yet exist and the modeling was conducted on the basis of various resource
6 hypotheticals, 2) the expedited nature of this proceeding has limited the opportunity for
7 independent, third-party expert review, and 3) various cost-related issues remain to be fully
8 litigated in a rate case proceeding. I also recommend that the Commission condition any
9 approval of the Special Contracts on Google paying all electric infrastructure costs required
10 to connect Google's data center without any cap and prohibit DTE from recovering any of
11 these costs from non-data center customers.

12 **IV. SPECIFIC PROPOSED RESOURCES (THAT THE COMPANY IS NOT**
13 **COMMITTING TO PAY FOR HERE) SHOULD BE IDENTIFIED IN THE**
14 **COMPANY'S IRP PROCESS AND NOT IN THIS PROCEEDING, AND THE**
15 **COMMISSION SHOULD DISREGARD INFORMATION ABOUT THE**
16 **BENEFITS ASSOCIATED WITH THE COMPANY'S MODELING CONSTRUCT**
17 **PROXY RESOURCE**

18 **Q. Please summarize this section.**

19 **A.** In this section, I review that the Company plans to develop a specific resource portfolio
20 (beyond the renewables and storage included in the CCAA) in its upcoming IRP filing as
21 is consistent with best practice. I agree with this approach and urge the Company to adopt
22 best practices as they relate to IRPs to ensure the development of an optimized, least-cost
23 resource portfolio. I demonstrate that, in this proceeding, the Company assumes the
24 existence of a proxy CCGT plus CCS resource that was developed for the singular purpose

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1 of performing the Company's customer benefit analysis. Finally, I recommend that the
2 Commission disregard all information DTE has provided regarding the various purported
3 benefits of the CCGT plus CCS resource given that no specific resources are being
4 proposed in this proceeding and any information about the benefits of a proxy resource is
5 irrelevant.

6 **Q. What does the Company state regarding selecting resources to address its resource**
7 **needs?**

8 **A.** The Company commits to comparing resource needs and associated costs (both with and
9 without the Customer's load) and selecting a specific resource portfolio in its upcoming
10 IRP filing,²³ as is appropriate given that, in MISO, "resource adequacy remains primarily
11 under state jurisdiction and handled through Integrated Resource Planning (IRP)."²⁴ As
12 mentioned in Section III above, the Company is not proposing any specific resources in
13 this proceeding and has committed to selecting actual resources "during the Company's
14 upcoming Integrated Resource Planning (IRP) proceeding"²⁵ where the Company promises
15 to evaluate "the incremental impact of the Customer's load on system resource needs by
16 comparing portfolios with and without that load and identifying the additional capacity or
17 energy resources required to reliably serve total system demand."²⁶ I agree with this
18 approach and emphasize the importance that the Company adopt best practices as they

²³ Ex MEC-2, Company Response to U-22058-MNS 1.2b & d.

²⁴ Gramlich, R. November 2021. Ensuring Low-Cost Reliability: Resource Adequacy Recommendations for a Clean Energy Grid. Prepared for American Council on Renewable Energy. Grid Strategies, LLC. Available at: <https://gridstrategiesllc.com/wp-content/uploads/2024/05/ensuring-low-cost-reliability-resource-adequacy-recommendations-for-a-clean-energy-grid.pdf>. p 8.

²⁵ Ex MEC-5, Company Response to U-22058-MNS 2.5c.

²⁶ Ex MEC-6, Company Response to U-22058-MNS 2.15a.

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1 relate to integrated resource planning, such as conducting resource adequacy assessments
2 and resource planning analysis in a coordinated and iterative manner that develops an
3 optimized, least-cost portfolio.²⁷

4 **Q. Does the Company make any resource assumptions in the current proceeding?**

5 **A.** Yes. To conduct its customer benefit analysis, the Company's assumes the existence of
6 generic energy storage resources totaling 480 MW of capacity, and a hypothetical proxy
7 CCGT with CCS, which—as described in Section III above—was developed as “generic
8 modeling construct” to ensure that the Company met its resource adequacy requirements
9 to be able to perform the customer benefit analysis.²⁸

10 **Q. What other information does the Company provide about the proxy CCGT with CCS**
11 **resource?**

12 **A.** Witness Burgdorf's direct testimony discusses the following as it relates to the CCGT with
13 CCS proxy resource:

- 14 • Its “market value for [DTE] customers”;
- 15 • Its ability to “offset potential future resource development costs” and “displace the
16 potential need for another resource in 2048”;
- 17 • How “74% of the cost of [the CCGT plus CCS] asset” will have been paid off (on an
18 NPV basis) at the conclusion of the contract with the Customer; and

²⁷ Biewald, B. et al. 2024. Best Practices in Integrated Resource Planning. Prepared by Synapse Energy Economics and Berkeley Lab. Available at: https://www.energy.gov/sites/default/files/2024-12/best_practices_irp_nov_2024_final_optimized.pdf.

²⁸ Ex MEC-3, Company Response to U-22058-CEOMEIBCIEIDE 1.20b & 1.21b.

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- How it will provide market value after the conclusion of the contract with the Customer.²⁹

Witness Burgdorf goes on to provide an example of net revenue requirements for potential 576 MW battery storage resource between 2048 and 2067 and how much of that net revenue requirement could be avoided with the proxy CCGT plus CCS resource.³⁰

Q. How should the Commission consider the Company's explanation of the various benefits of the proxy CCGT with CCS resource?

A. The Commission should disregard all information DTE has provided regarding the various benefits of the CCGT plus CCS proxy resource that was developed for the singular purpose of performing the Company's customer benefit analysis covering the years 2028 to 2041. Any claims about the proxy CCGT plus CCS' benefits for DTE or its ratepayers are irrelevant in this proceeding, given that the CCGT plus CCS resource is a purely hypothetical resource.

V. THE COMPANY SHOULD BE REQUIRED TO DEPLOY (AND GOOGLE PAY FOR) THE FULL PLANNED AMOUNT OF RENEWABLE AND STORAGE RESOURCES, AND UNDER-ACHIEVING THE RENEWABLE ENERGY GOAL WOULD IMPACT THE COMPANY'S RPS OBLIGATIONS

Q. Please summarize this section.

A. In this section, I review the Company's renewable energy and energy storage resource goals and demonstrate how the "up to" provision all but ensures that the Company will fall short of deploying 1,600 MW of renewable energy and 480 MW of energy storage

²⁹ Direct Testimony of Shawn D. Burgdorf, pp 13, 14, and 15.

³⁰ Burgdorf Direct, p1 5, lines 7-14.

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resources. I urge the Commission to condition its approval of the Special Contracts on the requirement that the Company deploy (and the Customer pay for) the full 1,600 MW and 480 MW goals. I also demonstrate how the Company is estimating its RPS compliance assuming that 1,600 MW of renewable energy resources are developed, and that falling short of that target would increase the Company's RPS compliance obligations and draw down the Company's REC surplus.

Q. How does the Company represent the amount of renewable energy and energy storage resources it will develop as part of the Special Contracts?

A. The Company notes that it will deploy "up to" 480 MW of energy storage projects and "up to" 1,600 MW of renewable energy projects.³¹

Q. What effect do the words "up to" have on the Company's 1,600 MW renewable energy and 480 MW energy storage goals?

A. The words "up to" set the 1,600 MW and 480 MW goals as ceilings rather than floors. The Company articulated this position in response to discovery, when it was clarified that "due to potential variability in the size of projects bid into the Request for Proposal (RFP)," it is possible that the energy storage and/or renewable energy project portfolios "cannot be configured to exactly match" their respective MW targets, which "**necessitat[es] the deployment of less overall capacity** (emphasis added)."³² The only reason that the Company would be "necessitated" to deploy less capacity than the stated goals is because

³¹ Foley Direct, p 23, lines 14-16.

³² Ex MEC-7, Company Response to U-22058-MNS 1.4a.

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1 the Company is including the words “up to” which all but ensures that outcome.

2 **Q. How should the Commission approach the Company’s 1,600 MW renewable energy**
3 **and 480 MW energy storage goals?**

4 **A.** I recommend that as a condition of approval of the Special Contracts, the Commission
5 require the Company to treat the 1,600 MW renewable energy and 480 MW energy storage
6 goals as floors, not ceilings. That way, in the event that the Company cannot procure
7 exactly 480 MW of energy storage resources or exactly 1,600 MW of renewable energy
8 resources, the Company will procure slightly more than 1,600 MW and/or 480 MW of
9 capacity and ensure the goals are reached.

10 **Q. Are there other reasons that it is important for the Company to procure at least 1,600**
11 **MW of renewable energy resources as planned?**

12 **A.** Yes, it is especially important that the Company achieve the 1,600 MW renewable energy
13 goal it has set out in this proceeding, because the Company is estimating its RPS
14 compliance assuming that 1,600 MW of renewable energy resources are developed. The
15 Customer is enrolling 40 percent of its total load (equal to 1,600 MW) in a “Voluntary
16 Green Pricing (VGP) Special Contract,” which reduces the Company’s REC compliance
17 obligations. Therefore, the Company is *excluding* the VGP portion of Google’s electric
18 load from its total retail sales calculations. Since RPS compliance is based on a percentage
19 of retail sales, this exclusion reduces the volume of sales subject to compliance and,
20 consequently, lowers the number of RECs the Company is required to obtain for
21 compliance purposes. As a result, the Company’s REC compliance obligation is reduced
22 by an amount corresponding to the VGP Special Contract (1,600 MW). Importantly, in its

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1 RPS compliance assessment, the Company is also assuming that 1,800 MW of renewable
2 energy is developed to serve another data center customer, Oracle, as outlined in Case U-
3 21990. On this basis, the Company claims that “because of the VGP Special Contract build
4 and the [Company’s] REC surplus, the Company can reduce its planned [renewable
5 energy] additions by 200 MW in 2033 and 50 MW in 2034, directly lowering costs for RPS
6 customers without compromising compliance.”³³ If the Company deploys less than the
7 1,600 MW renewable energy target, that will increase the Company’s RPS compliance
8 obligations accordingly.

9 **Q. What is the Company’s current REC balance?**

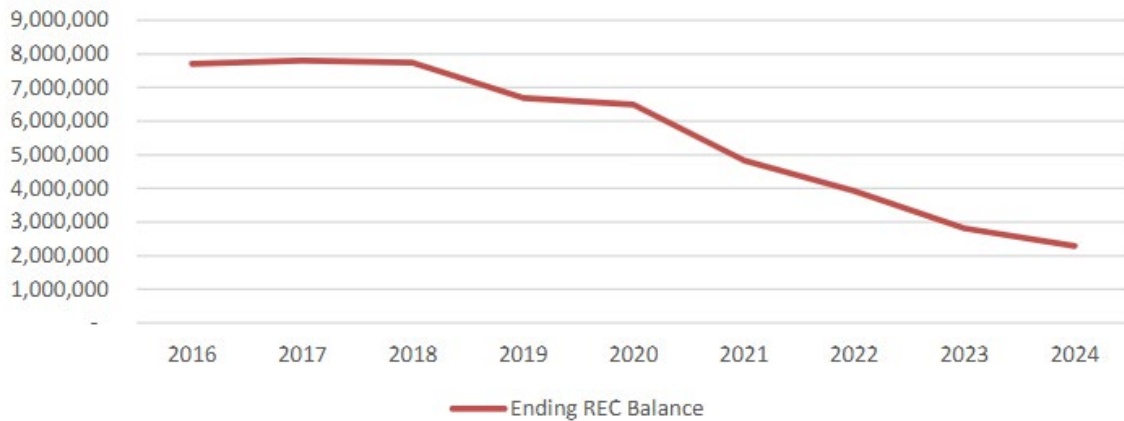
10 **A.** According to the Company’s Exhibit A-2, DTE anticipates a REC balance of 2.8 million
11 in 2026,³⁴ which is broadly in line with the Company’s REC balance in 2024 of just over
12 2 million, as demonstrated in Figure 2 below.

³³ Direct Testimony of Kevin L. Bilyeu, p 12.

³⁴ Company Exhibit A-2.

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Figure 2. DTE REC Balance, 2016-2024 (reproduced from Gold Direct, MPSC Case No. U-21830)



Q. How has the Company’s REC balance changed over the nine-year period ranging from 2016 to 2024?

A. The Company’s REC balance decreased markedly between 2016 and 2024—the Company drew down its REC balance by about 75 percent, from nearly 8 million RECs in 2016 to just over 2 million RECs in 2024 as demonstrated in Figure 2 above.³⁶

Q. How would the Company deploying less than 1,600 MW of renewable energy impact its REC balance?

A. The Company notes the importance of its “REC surplus” for ensuring RPS compliance given the addition of the Customer’s load, which means that deploying less than 1,600 MW of renewable energy resources would draw down the Company’s REC surplus more quickly than if the Company deploys renewable energy resources totaling at least 1,600

³⁵ MPSC Case No. U-21830. Direct Testimony and Exhibits of Eli K. Gold on behalf of Michigan Environmental Council. Figure 1.

³⁶ It should be noted that Figure 2 is based on DTE’s filed position in Case No. U-21830. In the Order in that case, the Commission adopted an ALJ recommendation based on Staff testimony that DTE must retire 6,047,203 RECs instead of 5,858,100, which further reduces DTE’s REC balance by 189,103 RECs from that reflected in the figure. See Case No. U-21830, Order, May 14, 2026, p. 5.

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1 MW.

2 **VI. RECOMMENDATIONS TO HELP THE COMPANY REACH ITS RENEWABLE**
3 **ENERGY AND ENERGY STORAGE GOALS**

4 **Q. Please summarize this section.**

5 **A.** In this section, I review the Company's reasoning for its confidence that it can develop
6 1,600 MW of renewable energy and 480 MW of energy storage resources as planned
7 (which are in addition to planned renewable energy resources from other proceedings), as
8 well as the conditions under which the Company says it may fail to reach those targets. I
9 demonstrate that the Company has failed to provide detailed information demonstrating
10 that it can reach the renewable energy and energy storage goals as defined, and that the
11 conditions under which the Company may fail to reach its targets are exceedingly common.
12 I conclude by recommending that the Company should develop specific commitments that
13 will help ensure the Company meets its renewable energy resource and energy storage
14 resource deployment goals.

15 **Q. Has the Company conducted any analyses or studies of the feasibility of acquiring**
16 **sufficient land, obtaining interconnection rights, receiving permitting approvals,**
17 **and/or completing the construction and/or contracting needed to achieve the**
18 **Company's annual build targets to reach 1,600 MW of renewable energy and 480**
19 **MW of energy storage by 2035?**

20 **A.** No. As clarified in response to discovery, the Company notes that it has "not conducted
21 any project-specific analyses or studies"³⁷ regarding the development of projects needed

³⁷ Ex MEC-8, Company Response to U-22058-MNS 2.10a.

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1 to meet its renewable energy and energy storage deployment goals.

2 **Q. Is the Company planning for renewable energy resources in addition to the 1,600 MW**
3 **proposed in the current proceeding?**

4 **A.** Yes. The 1,600 MW of renewable energy resources proposed in the current proceeding will
5 be additional to the Company's planned renewables in its Amended Renewable Energy
6 Plan and the Company's planned 1,800 MW of renewable energy to serve another data
7 center customer, Oracle, as outlined in Case U-21990 and the Company's RPS compliance
8 assessment in the current proceeding (which is addressed in more detail in Section VII
9 below). Information provided by the Company indicates that it plans to deploy between
10 1,800 to 2,000 MW of renewable energy resource in the years 2030, 2031, and 2032.³⁸

11 **Q. Does the Company feel confident that it can deploy 1,600 MW of renewable energy**
12 **and 480 MW of energy storage by 2035? If so, why?**

13 **A.** Yes. The Company believes that it has a "credible and sufficient foundation" to meet the
14 targets because it "already operates a substantial base of renewable resources and maintains
15 a robust set of projects in various stages of development. Together, these operating assets
16 and additions give the Company the flexibility to scale renewable capacity in line with the
17 Customer's load growth, supported by the Company's demonstrated history of successfully
18 developing renewable projects and by long-term resource plans that already anticipate
19 higher levels of renewable generation."³⁹

³⁸ Ex MEC-10, Company Response to U-22058-MNS-1.13a.

³⁹ Ex MEC-9, Company Response to U-22058-MNS 2.12b.

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1 **Q. Does the Company provide more detail regarding its “robust set of projects in various**
2 **stages of development”?**

3 **A.** No, the Company does not provide any additional detail about the projects in various stages
4 of development that it maintains provide it with “flexibility to scale renewable capacity in
5 line with the Customer’s load growth.”⁴⁰ When asked for more detailed information about
6 the projects in various stages of development in discovery, the Company responded that
7 the request sought “information that is not relevant to the issues presented” in this
8 proceeding.⁴¹

9 **Q. Does the Company note any conditions under which it would deploy less than 1,600**
10 **MW of renewable energy and 480 MW of energy storage?**

11 **A.** Yes. As discussed in Section V above, the Company notes that “potential variability in the
12 size of projects bid into the Request for Proposal (RFP)” could result in “the deployment
13 of less overall capacity.”⁴² Beyond RFP project size variability, the Company also notes
14 that it could procure less than the goals if:

- 15 • “Supply chain shortages [impact] the ability to deploy energy storage or renewable
16 energy projects
- 17 • Permitting constraints [impact] the ability to site energy storage or renewable energy
18 projects

⁴⁰ *Id.*

⁴¹ Ex MEC-11, Company Response to U-22058-MNS 3.14.

⁴² Ex MEC-7, Company Response to U-22058-MNS 1.4a.

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- MISO queue constraints [impact] the ability to interconnect energy storage or renewable energy projects”⁴³

Q. Are there situations under which the Company could end up deploying less than 1,600 MW of renewable energy or 480 MW of energy storage?

A. Yes. If the Company fails to properly plan and prepare for common hurdles to renewable energy development, it could end up falling short of these renewable energy and energy storage goals in the CCAA. Supply chains can be disrupted for political, logistical, or operational reasons, and a single disruption can ripple across markets.⁴⁴ The most recent disruption came after the closure of the Strait of Hormuz, where shipments of inputs for renewable energy and battery storage development have been blocked.⁴⁵ Permitting constraints are also common barriers to renewable energy and battery deployment across the United States, with many jurisdictions establishing maximum height limits for turbines, setback requirements, and other restrictions that can cause project delays and cancellations.⁴⁶ It is important to note that Michigan passed legislation in 2023 (Public Act 233) that created a streamlined siting process for renewable energy and energy storage

⁴³ Ex MEC-12, Company Response to U-22058-CEOMEIBCIEIDE 1.41a.

⁴⁴ Moody's. Match 9, 2026. "Why supplier resilience now determines the pace of renewable buildouts." Available at: <https://www.moodys.com/web/en/us/insights/compliance-tprm/why-supplier-resilience-now-determines-the-pace-of-renewable-buildouts.html>

⁴⁵ Errick, K & Rizkala, A. April 27, 2026. "Middle East war hits renewable energy supply chains directly and indirectly." *S&P Global*. Available at: <https://www.spglobal.com/energy/en/news-research/latest-news/electric-power/042726-middle-east-war-hits-renewable-energy-supply-chains-directly-and-indirectly>

⁴⁶ (1) Light, A., & Saha, D. March 27, 2026. "Clean Energy's Growing Problem: Restrictive Siting Laws." *World Resource Institute*. Available at: <https://www.wri.org/insights/clean-energy-restrictive-siting-laws> (accessed June 4, 2026); (2) Katz, J., & Baillargeon, N. 2025. "Balancing Participation and Speed: A Polycentric Governance Lens on Renewable-Energy Siting." *Policy Studies Journal*. Available at: <https://onlinelibrary.wiley.com/doi/10.1111/psj.70091> (accessed June 4, 2026); (3) Kupec, A. January 15, 2026. "UMASS Amherst Study Shows Fragmented State and Local Authority Complicates Clean Energy Rollout." University of Massachusetts Amherst. Available at: <https://www.umass.edu/news/article/umass-amherst-study-shows-fragmented-state-and-local-authority-complicates-clean> (accessed June 4, 2026).

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1 projects.⁴⁷ Interconnection queues have also been a common barrier for renewable energy
2 and battery storage deployment in recent years, and the issue is expected to persist in the
3 near future.⁴⁸ MISO’s March 2026 interconnection queue shows that 77 percent of the 42
4 GWs of generation with approved interconnection agreements expecting delays in
5 commercial operation dates were renewable energy or battery storage projects.⁴⁹ The total
6 capacity of all delayed projects was reported to be 31 percent greater than the previous
7 quarter, indicating that MISO is facing increased backlogs in the interconnection queue,
8 which could directly impact the Company’s interconnection timeline for new renewable
9 resources.⁵⁰

10 **Q. What do you recommend to help ensure the Company reaches its goal of deploying**
11 **1,600 MW of renewable energy and 480 MW of energy storage?**

12 **A.** I recommend the Commission require the Company to develop specific commitments that
13 will help ensure the Company meets its renewable energy resource and energy storage
14 resource deployment goals, such as:

⁴⁷ The law went into effect on November 29, 2024 and created an option for renewable energy and energy storage developers to go directly to the Commission to construct a facility if the local government does not have a compatible renewable energy ordinance (“CREO”). If a local government has a CREO, then developers must first propose their project at the local level. If the project is denied at the local level, the developer may then apply to the Commission. See: (1) <https://www.michigan.gov/mpsc/commission/workgroups/2023-energy-legislation/> (accessed June 4, 2026), and (2) Mills, Krol, and Stoetzer, “What Local Governments Should Know About Michigan’s New Renewable Energy Siting Policies” available at: <https://graham.umich.edu/media/files/FAQ-How-HB5120-Works.pdf>. p 4.

⁴⁸ U.S. Department of Energy. April 2022. “Queued Up But in Need of Transmission.” Available at: <https://www.energy.gov/documents/queued-upbut-need-transmission>

⁴⁹ Midcontinent Independent System Operator. March 24, 2026. “Generator Interconnection Queue Update [PowerPoint Slides].” Available at: <https://cdn.misoenergy.org/20260324%20System%20Planning%20Committee%20of%20the%20BOD%20Item%2005%20Generator%20Interconnection%20Queue%20Update745972.pdf>

⁵⁰ Midcontinent Independent System Operator. March 24, 2026. “Generator Interconnection Queue Update [PowerPoint Slides].” Available at: <https://cdn.misoenergy.org/20260324%20System%20Planning%20Committee%20of%20the%20BOD%20Item%2005%20Generator%20Interconnection%20Queue%20Update745972.pdf>

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- 1 • The Company should issue Requests for Proposals (RFPs) that seek more renewable
2 energy and energy storage resources than the proposed annual build amounts to help
3 ensure that the targets are met in the most cost-effective manner possible and that
4 annual deployment targets are achieved.
- 5 • The Company should pursue behind-the-meter and distributed energy resources
6 (“DERs”) as part of its renewable energy and energy storage goals. Front-of-meter and
7 behind-the-meter resources can both be used to generate RECs and help the Company
8 reach its RPS obligations.
- 9 • The Company should conduct analyses and/or studies of the feasibility of acquiring
10 sufficient land, obtaining interconnection rights, receiving permitting approvals, and
11 completing the construction and/or contracting needed to achieve the annual renewable
12 energy and energy storage plans.
- 13 • The Company should make specific commitments regarding how it will respond to
14 each potential situation under which the Company would be at risk of deploying less
15 than its renewable energy and energy storage resource deployment goals (i.e. supply
16 chain shortages, permitting constraints, MISO queue constraints).
 - 17 ○ As a purely illustrative example, if the Company encounters MISO queue
18 constraints, the Company could commit to taking advantage of MISO’s Surplus
19 Interconnection Service (SIS) to develop renewable energy and/or energy
20 storage projects at existing points of interconnection with available surplus
21 interconnection capacity in DTE’s service area. In response to discovery, the
22 Company noted that it “has evaluated the use of MISO’s Surplus

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Interconnection Service (SIS) to advance energy storage and renewable energy goals.”⁵¹

VII. ISSUES WITH THE COMPANY’S RPS COMPLIANCE ANALYSIS APPROACH

Q. Please summarize this section.

A. In this section, I review the Company’s RPS obligations and its RPS compliance assessment. I demonstrate that the Company’s RPS compliance assessment has various issues, including an assumption of renewable energy capacity amounts that are uncertain, a calculation error that changes the Company’s status in 2032 from RPS compliance to noncompliance; and REC surplus forecasts that are not aligned with historical trends. I recommend that the Commission require the Company to reconduct its RPS compliance assessment in its forthcoming Renewable Energy Plan (“REP”) such that the Company identifies the amount of capacity that would be required in each year to achieve RPS compliance (rather than assume uncertain renewable energy capacity amounts), and sets forth a clear plan for bringing online at least that amount of renewable capacity in each year.

Q. What are the Company’s RPS obligations?

A. The Company notes that, as established in Public Act 235 of 2023, electric providers like DTE “shall achieve a REC [Renewable Energy Credit] portfolio of at least the following:

a) Through 2029, 15% of total retail sales, b) In 2030 through 2034, 50% of total retail

⁵¹ Company response to U-22058-MNS 3.8.

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1 sales, c) In 2035 and each year thereafter, 60% of total retail sales.”⁵²

2 **Q. Does the Company anticipate it can meet its RPS obligations with the addition of the**
3 **Customer’s load?**

4 **A.** Yes. The Company’s Exhibit A-2 shows the Company anticipates RPS compliance in a
5 scenario where the load from the Customer is met, and the load from another data center
6 customer (Oracle as in Case U-21990) is met as well.

7 **Q. How does the Company approach its RPS compliance assessment?**

8 **A.** As discussed in Section V above, the Customer is enrolling 40 percent of its total load
9 (equal to 1,600 MW—the amount of renewable energy capacity proposed) in a VGP
10 Special Contract which reduces the Company’s REC compliance obligations. In Exhibit
11 A-2, DTE reduces the total sales subject to RPS obligations by subtracting the sales
12 associated with the Customer’s VGP Special Contract. This means that, out of Google’s
13 total load of 7,884 GWh (which the Company estimates to be equivalent to 4 GW), 60
14 percent (or 2.4 GW) is subject to the Company’s RPS requirements.

15 After the Company determines its total sales subject to RPS obligations, it estimates annual
16 required REC amounts for two scenarios: “Base Case without Data Center Load” and
17 “Updated RPS” (which represents the Base Case adjusted to include data center load from
18 Google and Oracle). The Company also estimates annual REC balances for two scenarios:
19 “Base Case without Data Center Load” and “With Additional 1800 MW for [Oracle] and

⁵² Bilyeu Direct, p 5.

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1 1600 MW VGP for [Google].”⁵³

2 **Q. What does the Company’s RPS compliance assessment conclude?**

3 **A.** The Company’s analysis results indicate that the Company is RPS compliant in each year
4 of the forecasting period (2026 to 2045) in the “Base Case without Data Center Load” and
5 “With Additional 1800 MW for [Oracle] and 1600 MW VGP for [Google]” scenarios, but
6 not in the “Updated RPS” scenario (which is the Base Case adjusted to include data center
7 load from Google and Oracle), where the Company finds itself to be RPS non-compliant
8 in 2031 through 2041.

9 **Q. What does the Company conclude about its renewable energy needs given its RPS**
10 **compliance assessment findings?**

11 **A.** The Company concludes that no “additional renewable energy projects will need to be
12 deployed to meet its Renewable Portfolio Standard (“RPS”) obligations as a result of the
13 Customer’s load.”⁵⁴ More specifically, the Company maintains that—due to the VGP
14 Special Contract for 1,600 MW of Google’s load and the Company’s REC surplus—the
15 Company can actually reduce the amount of renewable energy it requires for RPS
16 compliance “by 200 MW in 2033 and 50 MW in 2034.”⁵⁵

⁵³ Company Exhibit A-2.

⁵⁴ Ex MEC-13, Company Response to U-22058-MNS 2.14a.

⁵⁵ Bilyeu Direct, p 12.

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1 **Q. How did the Company develop its “With Additional 1800 MW for [Oracle] and 1600**
2 **MW VGP for [Google]” scenario?**

3 **A.**The Company developed its “With Additional 1800 MW for [Oracle] and 1600 MW VGP
4 for [Google]” scenario by assuming the 1,600 MW renewable energy target from the
5 current proceeding (which, again, is exempt from RPS requirements and subtracted from
6 the total sales subject to RPS provisions in the Company’s RPS compliance assessment
7 because of the VGP Special Contract), and assuming 1,800 MW of renewable energy from
8 another data center customer, Oracle, as represented in Case U-21990. In response to
9 discovery, the Company clarified that the 1,800 MW from Oracle was determined as a
10 “reasonable midpoint” because “additional renewable energy capacity needed to satisfy the
11 higher RPS requirements associated with the first data center customer could range from
12 443 MW, if the Company fully utilizes its projected REC bank, up to 3.2 GW.”⁵⁶ In other
13 words, additional renewable energy needed to serve Oracle’s load while maintaining RPS
14 compliance could range between 443 MW on the low end and 3,200 MW on the high end—
15 the Company utilizes 1,800 MW in its RPS compliance modeling as the approximate
16 median of those two numbers.

17 **Q. Are the Company’s RPS compliance assessment assumptions of 1,800 MW renewable**
18 **energy for Oracle and 1,600 MW VGP renewable energy for Google certain?**

19 **A.**No, both 1,800 MW and 1,600 MW are uncertain numbers. As discussed in Sections V and
20 VI above, the 1,600 MW of renewable energy proposed in this proceeding may not be
21 reached—either because variability in project sizes result in less overall capacity than 1,600

⁵⁶ Ex MEC-14, Company Response to U-22058-MNS 2.12a.

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1 MW or if the Company fails to properly plan and prepare for common hurdles to renewable
2 energy development including supply chain shortages, permitting constraints, and/or
3 MISO queue constraints. As discussed in Section VI, the Company's proposed amount of
4 renewable energy resources—considering this proceeding, proceeding U-21990, and the
5 Company's Renewable Energy Plan—is ambitious and will require specific, targeted
6 commitments, plans, and strategies to ensure they are achieved.

7 More critical is the 1,800 MW for Oracle because that amount is included in the Company's
8 considerations of sales subject to RPS provisions (unlike the 1,600 MW which is exempt
9 from RPS requirements and subtracted from the total sales subject to RPS). Unfortunately,
10 taking a “reasonable midpoint” between two numbers that range widely cannot produce
11 reliable RPS compliance results because it begs the question: What would the Company's
12 RPS compliance look like if the true number were 443 MW, the low end of the range?
13 When asked in discovery, the Company clarified that it has not performed an RPS
14 compliance analysis that considers either the lower or upper bounds of the range (i.e. 443
15 MW or 3,200 MW).⁵⁷

16 **Q. Are there any other issues with the Company's RPS compliance assessment?**

17 **A.** Yes. There are two additional issues to which I would like to call the Commission's
18 attention: 1) a calculation error that—if corrected—results in the Company being RPS non-
19 compliant in the year 2032 under the “With Additional 1800 MW for [Oracle] and 1600
20 MW VGP for [Google]” scenario, and 2) annual REC balances that grow substantially
21 between 2038 and 2045 when the Company's REC balance reaches nearly 100 million

⁵⁷ Ex MEC-15, Company Response to U-22058-MNS 3.13.

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1 (recall that the Company currently has a REC surplus of about 2.8 million and that the
2 highest REC balance it has achieved since 2016 is about 8 million).

3 **Q. Please explain the Company's RPS compliance calculation error.**

4 **A.** The Company appears to have incorrectly calculated 5 percent of its RPS requirement in
5 Line No. 24 of its Exhibit A-2, starting in year 2028 and in each year thereafter. When I
6 fixed the error (making no other changes), I found that the Company would be RPS non-
7 compliant in 2032 (see my workpapers for a summary of the error and its correction).

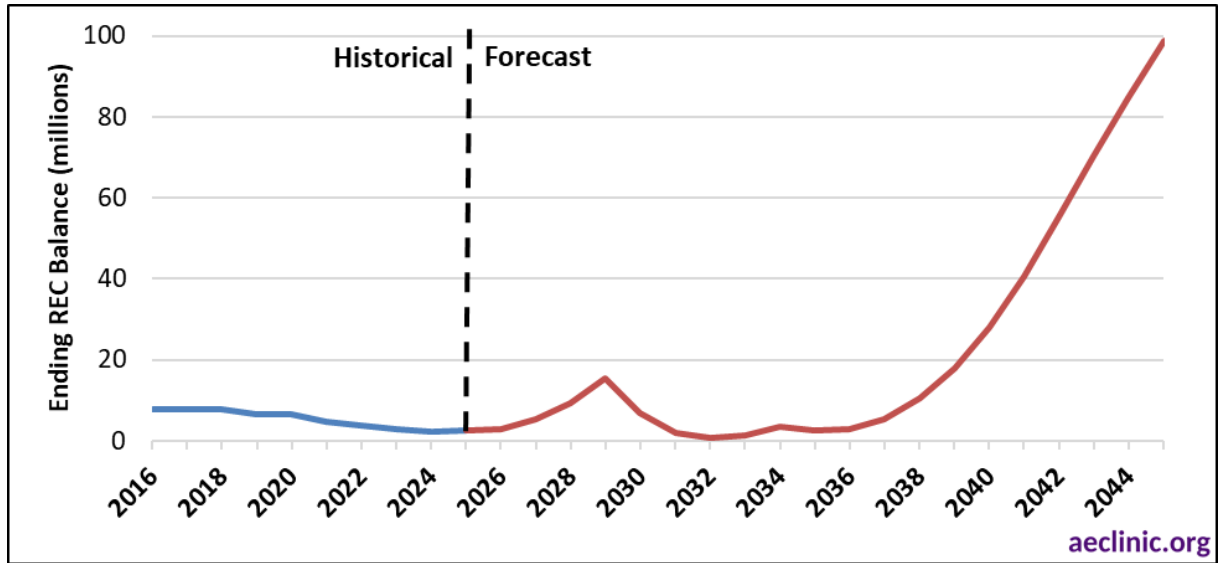
8 **Q. Please explain the Company's REC balance as determined in the Company's RPS**
9 **compliance assessment.**

10 **A.** The Company's RPS compliance assessment demonstrates that, in the scenario where
11 Google and Oracle data centers are online and the 1,600 MW of RPS-exempt and 1,800
12 MW of RPS-subject capacity is online, the Company's annual REC balance increases
13 steadily between 2026 and 2029 when the balance reaches 15.3 million, then steadily
14 declines and stays relatively low (i.e. about 5.5 million or less) until 2038. Starting in 2038,
15 the annual REC balances increase rapidly, reaching nearly 30 million in 2040 and nearly
16 100 million in 2045, as demonstrated in Figure 3 below. For reference, between 2016 and
17 2024, the Company's REC balance ranged from nearly 8 million in 2016 down to about 2

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million in 2024 (see Figure 3).

Figure 3. DTE Historical REC Balance, 2016-2024 and DTE Forecasted REC Balance, 2026-2045



Q. What recommendations do you have for the Company regarding its RPS compliance assessment?

A. I recommend that, as a condition of approval of the Special Contracts, the Commission direct the Company to amend its RPS compliance assessment in its forthcoming Renewable Energy Plan (“REP”) as part of the Company’s IRP such that the Company identifies the amount of capacity that would be required in each year to achieve RPS compliance (e.g. 100 MW in 2030, 75 MW in 2031, etc.) rather than assume renewable energy capacity amounts that are not firm numbers (i.e. the 1,600 MW for Google and 1,800 MW for Oracle). At the very least, the Company should be required to run the RPS compliance assessment using the most conservative estimates the Company has for the total amount of

⁵⁸ 1) Company Exhibit A-2; 2) MPSC Case No. U-21830. Direct Testimony and Exhibits of Eli K. Gold on behalf of Michigan Environmental Council. Figure 1.

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renewable energy that will be deployed to serve each data center customer.

VIII. RECOMMENDATIONS

Q. Please summarize your conclusions and recommendations to the Commission.

A. I recommend that the Commission:

(1) I urge the Commission to not predetermine that the Contracts will result in the Company's claimed costs or benefits for customers given that: 1) no specific resource proposals yet exist and the modeling was conducted on the basis of various resource hypotheticals, 2) the expedited nature of this proceeding has limited the opportunity for independent, third-party expert review of the claimed customer benefit, and 3) various cost-related issues remain to be fully litigated in a rate case proceeding;

(2) The Commission should disregard all information DTE has provided regarding the various purported benefits of the CCGT plus CCS proxy resource that was developed for the singular purpose of performing the Company's customer benefit analysis covering the years 2028 to 2041. Any claims about the proxy CCGT plus CCS' benefits for DTE or its ratepayers are irrelevant in this proceeding, given that the CCGT plus CCS resource is a purely hypothetical resource;

(3) I recommend that the Commission condition any approval of the Special Contracts on Google paying all electric infrastructure costs required to connect Google's data center without any cap and prohibit DTE from recovering any of these costs from non-data center customers;

(4) I urge the Commission to condition its approval of the Special Contracts on the requirement that the Company deploy (and the Customer pay for) the full 1,600

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1 MW and 480 MW goals and treat the goals as floors, not ceilings. That way, in the
2 event that the Company cannot procure exactly 480 MW of energy storage
3 resources or 1,600 MW of renewable energy resources, the Company will procure
4 slightly more than the target to ensure the target is reached;

5 (5) I recommend the Commission require the Company to develop specific
6 commitments that will help ensure the Company meets its renewable energy
7 resource and energy storage resource deployment goals, such as:

- 8 • The Company should issue RFPs that seek more renewable energy and
9 energy storage resources than the proposed annual build amounts to help
10 ensure that the targets are met in the most cost-effective manner possible
11 and that annual deployment targets are achieved.
- 12 • The Company should pursue behind-the-meter and DERs as part of its
13 renewable energy and energy storage goals. Front-of-meter and behind-the-
14 meter resources can both be used to generate RECs and help the Company
15 reach its RPS obligations.
- 16 • The Company should conduct analyses and/or studies of the feasibility of
17 acquiring sufficient land, obtaining interconnection rights, receiving
18 permitting approvals, and completing the construction and/or contracting
19 needed to achieve the annual renewable energy and energy storage plans.
- 20 • The Company should make specific commitments regarding how it will
21 respond to each potential situation under which the Company would deploy
22 less than its renewable energy and energy storage resource deployment

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goals (i.e. supply chain shortages, permitting constraints, MISO queue constraints); and

(6) I recommend that the Commission, as a condition of approval of the Special Contracts, order the Company to amend its RPS compliance assessment in its forthcoming REP as part of the Company's IRP such that the Company identifies the amount of capacity that would be required in each year to achieve RPS compliance (e.g. 100 MW in 2030, 75 MW in 2031, etc.) rather than assume renewable energy capacity amounts that are not firm numbers (i.e. the 1,600 MW for Google and 1,800 MW for Oracle). At the very least, the Company should be required to run the RPS compliance assessment using the most conservative estimates the Company has for the total amount of renewable energy that will be deployed to serve each data center customer.

My silence regarding any position taken by the Company in its application or direct testimony in this proceeding does not indicate my endorsement of that position.

Q. Does that complete your testimony?

A. Yes.

1 MS. HILLYER: Thank you, your Honor. I
2 have nothing further.

3 JUDGE STALEY: Thank you. That concludes
4 your case?

5 MS. HILLYER: Yes.

6 JUDGE STALEY: All right. I'm just
7 keeping track of these as I go. All right. And then
8 MEICEO.

9 MS. DUCKWORTH: Thank you, your Honor.
10 At this time, on behalf of MEICEO, I move to bind into
11 the record the Direct Testimony of William D. Kenworthy
12 consisting of a cover page, a table of contents, and 42
13 pages of questions and answers. I also move for the
14 admission of Mr. Kenworthy's testimony Exhibits MEICEO-1
15 and MEICEO-2.

16 JUDGE STALEY: All right. Is there any
17 objection to the binding in of the prefiled Direct
18 Testimony of William D. Kenworthy, or the admission of
19 Exhibits MEICEO-1 and MEICEO-2?

20 Hearing none, the prefiled Direct
21 Testimony of William D. Kenworthy is bound into the
22 record, and Exhibits MEICEO-1 and MEICEO-2 are admitted
23 into evidence.

24 (Direct Testimony bound in.)

25 - - -

**STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION**

In the matter of the application of DTE	)	
ELECTRIC COMPANY for approval of	)	Docket No. U-22058
special contracts and for other relief.	)	

DIRECT TESTIMONY OF

WILLIAM D. KENWORTHY

ON BEHALF OF

**THE MICHIGAN ENERGY INNOVATION BUSINESS COUNCIL, INSTITUTE FOR
ENERGY INNOVATION, ECOLOGY CENTER, ENVIRONMENTAL LAW & POLICY
CENTER, UNION OF CONCERNED SCIENTISTS, AND VOTE SOLAR**

June 5, 2026

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1 **I. INTRODUCTION AND SUMMARY**

2 **Q: Please state your name and business address.**

3 A: My name is William D. Kenworthy. My business address is 309 W. Washington St., Suite
4 800, Chicago, Illinois 60606.

5 **Q: By whom are you employed and in what capacity?**

6 A: I serve as Senior Regulatory Director – Midwest for Vote Solar. I oversee policy
7 development and implementation related to large-scale and distributed solar generation in
8 the region. I also review regulatory filings, perform technical analyses, and testify in
9 commission proceedings on issues relating to solar generation.

10 Vote Solar is an independent 501(c)(3) nonprofit working to repower the U.S. with
11 clean energy by making solar power more accessible and affordable through effective
12 policy advocacy. Vote Solar seeks to promote the development of solar at every scale, from
13 distributed rooftop solar to large utility-scale plants. Vote Solar has over 90,000 members
14 nationally, including over 2,700 members in Michigan. Vote Solar is not a trade
15 organization, nor does it have corporate members.

16 **Q: Please summarize your qualifications, experience, and education.**

17 A: I have over 30 years of experience in the energy industry in both the public and private
18 sectors working in the renewable energy business and in energy policy. Since joining Vote
19 Solar in 2018, I have provided expert testimony in regulatory proceedings before utility
20 commissions in six states—Michigan, Illinois, Wisconsin, Iowa, Indiana, and Virginia—
21 with more than 50 individual filings spanning rate design, distributed energy resources,
22 integrated resource planning, and grid modernization. Previously, I spent eight years in
23 solar energy project development working primarily on commercial and industrial

1 distributed solar projects in the Midwest. I began my career in energy policy at the U.S.
2 House Energy and Commerce Committee and worked for over a decade after that working
3 in federal energy and environmental policy with a trade association and for individual
4 electric utilities. A copy of my resume is attached as Exhibit MEICEO-1.

5 I received a Master of Public & Private Management degree from the Yale
6 University School of Management with a concentration in Regulation and Competitive
7 Strategy. My research in graduate school focused on regulatory theory and practice. I also
8 have a Bachelor of Science in Foreign Service from Georgetown University.

9 **Q: Have you testified before the Michigan Public Service Commission previously?**

10 **A:** Yes, I have provided testimony in the following proceedings before the MPSC:

- 11 • U-20162 – DTE Electric Co. (“DTE” or “the Company”) Electric Rate
12 Case
- 13 • U-20359 – Indiana Michigan Power Co. Electric Rate Case
- 14 • U-20471 – DTE Electric Co. Integrated Resource Plan
- 15 • U-20561 – DTE Electric Co. Electric Rate Case
- 16 • U-20697 – Consumers Energy Co. Electric Rate Case
- 17 • U-20649 – Consumers Energy Co. Voluntary Green Pricing Case
- 18 • U-20713/U-20851 – DTE Electric Co. Consolidated Voluntary Green
19 Pricing and Renewable Energy Plan Amendment cases
- 20 • U-21090 – Consumers Energy Co. Integrated Resource Plan
- 21 • U-21134 – Consumers Energy Co. Voluntary Green Pricing Case
- 22 • U-20836 – DTE Electric Co. Electric Rate Case
- 23 • U-21124 – Consumers Energy Co. Electric Rate Case

- U-21193 – DTE Electric Co. Integrated Resource Plan
- U-21297 – DTE Electric Co. Electric Rate Case
- U-21389 – Consumers Energy Co. Electric Rate Case
- U-21375 – DTE Electric Co. Voluntary Green Pricing Case
- U-21461 – Indiana Michigan Power Co. Electric Rate Case
- U-21534 – DTE Electric Co. Electric Rate Case
- U-21585 – Consumers Energy Co. Electric Rate Case
- U-21662 – DTE Electric Co. Renewable Energy Plan Case
- U-21860 – DTE Electric Co. Rate Case

A complete listing of my testimony and comments is attached as Exhibit MEICEO- 2.

Q: Are you sponsoring any exhibits?

A: Yes, I am sponsoring the following exhibits:

- Exhibit MEICEO-1: Resume of William D. Kenworthy
- Exhibit MEICEO-2: List of Testimony and Comments of William D. Kenworthy

II. PURPOSE OF TESTIMONY

Q: On whose behalf are you appearing in this case?

A: I am testifying on behalf of the Ecology Center, Environmental Law & Policy Center, Union of Concerned Scientists, and Vote Solar, collectively the “Clean Energy Organizations” or “CEO,” as well as the Michigan Energy Innovation Business Council (“Michigan EIBC”) and the Institute for Energy Innovation (“IEI”). I will refer to these organizations collectively as MEI/CEO.

1 **Q: What is the purpose of your testimony?**

2 A: The purpose of my testimony is to evaluate whether DTE’s evidentiary showing is
3 sufficient to support the findings the Commission must make to approve the Special
4 Contracts—namely, that the contracts are just and reasonable and in the public interest and
5 that the costs caused by the new Customer load are not shifted to other ratepayers. DTE
6 supports that request with two things: a with-and-without cost-of-service study
7 comparison, and a calculation it characterizes as an approximately \$1.7 billion
8 Affordability Benefit to other customers. My testimony addresses both. I assess whether
9 the record demonstrates the absence of cost shifting under the cost-causation framework
10 the Commission articulated in U-21859 and reaffirmed in U-21990, and because DTE has
11 affirmatively put the \$1.7 billion Affordability Benefit in issue, whether the record is
12 sufficient to rely on that asserted benefit in finding the contracts reasonable, prudent, and
13 in the public interest. I conclude that, while DTE’s analysis is built on reasonable methods,
14 it is not sufficient on its own to support a durable finding of no cost shifting, and I
15 recommend that any approval be conditioned on systematic back-end verification, true-up
16 procedures, and an enforceable affordability backstop.

17 **Q: Before turning to your analysis, are there aspects of this proceeding you wish to**
18 **acknowledge at the outset?**

19 A: Yes. I appreciate that DTE filed these contracts before the Commission as a contested case.
20 That choice gives the Commission and intervenors a transparent record on which to
21 examine the issues that a commitment of this magnitude presents, and it is consistent with
22 the framework the Commission established in its November 6, 2025 final order in Case
23 No. U-21859, as well as its December 18, 2025 order in Case No. U-21990.

1 **Q: Is there anything else you wish to acknowledge?**

2 A: Yes. I also appreciate the stated intention of DTE and Google not to adversely impact other
3 customers, and Google’s commitment to pursue aggressive clean energy goals through the
4 Clean Capacity Accelerator Agreement (“CCAA”). Those commitments establish a
5 constructive premise for this proceeding and inform the conditions and back-end
6 verification I recommend below. MEI/CEO witness Lee Shaver discusses the nature of
7 Google’s clean energy commitments—including its goals of 24/7 carbon-free energy by
8 2030 and 100% annual renewable matching—and evaluates whether DTE’s proposed
9 resource plan under the CCAA is sufficient for Google to achieve those objectives.

10 **Q: At a high level, what is DTE asking the Commission to find about the net financial**
11 **effect of these contracts on other customers?**

12 A: DTE’s Application in this case asserts that the Special Contracts reflect “a reasonable and
13 prudent balance between the advantages of serving a new large load customer and
14 protecting existing customers from risk and potential cost subsidies.” The formal request
15 is in Paragraph 19 of the Application, which asks the Commission to “[d]etermine that the
16 Special Contracts are reasonable and prudent and enter an order approving the Special
17 Contracts as consistent with all applicable law.”¹ DTE further asserts that the approvals
18 sought “will not increase the cost of service to the Company’s customers” and accordingly
19 could have been authorized without notice or hearing under MCL 460.6a(3), although DTE
20 filed the matter as a contested case.² The narrow textual relief DTE seeks is therefore a
21 finding of reasonableness and prudence, paired with the predicate factual finding that the
22 contracts will not increase the cost of service to existing customers.

¹ DTE Application for Approval of Special Contracts and other relief, Case No. U-22058, at p. 5, paragraph 19(E).

² *Id.* at 2.

1 What DTE asserts in support of that finding, however, goes well beyond the
2 absence of cost shifting. DTE asserts that the Special Contracts will produce a substantial,
3 affirmative net financial benefit to existing customers. The Application states that “the
4 Special Contracts generate a benefit for existing customers” through (i) base sales under
5 D11, (ii) incremental Power Supply Cost Recovery (“PSCR”) savings, and (iii) the pull-
6 ahead of customer-funded storage, and that “the Company estimates that the impact of the
7 Customer’s new load will provide a net benefit across all of its customer classes.”³ DTE
8 quantifies that asserted benefit at approximately \$1.7 billion (nominal, 2028–2047)⁴, and
9 DTE witness Foley characterizes the figure as a “\$1.7 billion benefit to the Company’s
10 other customers.”⁵ I will refer to this calculation as the Affordability Benefit going forward.
11 This assertion is materially more demanding than a simple no-cost-shift showing. A finding
12 by the Commission that the contracts merely avoid harm to other customers is significantly
13 different than a finding that the contracts deliver \$1.7 billion of affirmative benefit,
14 although both rely on the same demonstration.

15 As an example of how these determinations are distinct, it would be possible for a
16 net benefit (even a substantial one as \$1.7 billion) to result from the Customer’s new load
17 **and** for a cost shift to occur if the costs and benefits of the new load are not allocated
18 properly. Conversely, it is also possible that the net costs and benefits of serving the
19 Customer could be a net cost to the system but **not** result in a cost shift to other customers.
20 Importantly, whether cost shifts occur will be determined through the allocation of costs in
21 future DTE rate cases.

³ Application at ¶ 14.

⁴ Exhibit A-19, line 14.

⁵ Direct Testimony of Neal T. Foley on behalf of DTE Electric Company (“Foley Direct”), Case No. U-22058, at 8–9.

1 My testimony addresses both the demonstration of no cost shift and the
2 Affordability Benefit calculation. First, I address whether DTE’s evidentiary showing
3 supports the formal finding it requests under MCL 460.6v(4)(a) and the cost-causation/no-
4 cost-shift framework the Commission articulated in U-21859 and reaffirmed in U-21990—
5 that is, whether the record demonstrates that other customers are protected from costs
6 caused by the Customer’s new load. Second, because DTE has put the \$1.7 billion
7 Affordability Benefit affirmatively in issue, I address whether DTE’s evidentiary showing
8 is sufficient, on this record, to support reliance on that asserted benefit as a basis for finding
9 the Special Contracts reasonable and prudent and in the public interest.

10 **Q: Please summarize your principal observations.**

11 A: DTE’s showing relies on a comparison and a calculation, and three features of that showing
12 warrant the Commission’s attention up front:

- 13 • The bulk of the benefits in the Affordability Benefits calculation rely on
14 DTE’s with-and-without cost-of-service study (“COSS”) comparison,
15 which assumes essentially no incremental utility rate base is required to
16 serve the new approximately 1,000 MW load. Whether that assumption
17 holds is a threshold question for any no-cost-shift finding by the
18 Commission;
- 19 • The cost side of the \$1.7 billion Affordability Benefit calculation is
20 anchored on a hypothetical 727 MW gas-with-carbon-capture plant
21 assumed in service in 2033. DTE acknowledges that plant is a placeholder
22 that the 2026 IRP may or may not adopt—meaning the Commission is

1 being asked to approve these contracts on the basis of a resource decision
2 it will make later, in the IRP; and

- 3 • The \$1.7 billion Affordability Benefit figure is a nominal sum over 20
4 years, not a present value, and DTE's own modeling shows four years
5 (2035–2038) in which other customers bear net cost rather than receive net
6 benefit.

7 Together, these findings support conditioning any approval with systematic back-
8 end verification, true-up procedures, and an enforceable affordability backstop—rather
9 than treating the single-point \$1.7 billion Affordability Benefit estimate as a complete
10 answer to the no-cost-shift and public-interest questions that the Commission is being
11 asked to determine here.

12 **III. INTRODUCTION OF MEI/CEO WITNESSES**

13 **Q: Who are the other witnesses appearing on behalf of MEI/CEO in this proceeding,**
14 **and what is the scope of their testimony?**

15 A: MEI/CEO are presenting four direct witnesses, including myself. Each of us addresses a
16 distinct slice of the case.

- 17 • William D. Kenworthy — Vote Solar. My direct testimony addresses (i)
18 the standard the Commission applies to special-contract approval and the
19 U-21859 and U-21990 cost-causation framework, (ii) DTE's cost-of-
20 service comparison and the \$1.7 billion Affordability Benefit estimate,
21 (iii) the transmission cost-allocation question, and (iv) the back-end
22 verification and affordability-backstop framework that I recommend the
23 Commission adopt as a condition of any approval.

- 1 • Chelsea Hotaling — Energy Futures Group. Ms. Hotaling is a Senior
2 Consultant at Energy Futures Group. Her direct testimony evaluates the
3 resource adequacy of DTE’s system with the Customer’s load and
4 proposed resources and identifies some of the cost and benefit categories
5 that might change with updated capacity expansion modeling in the
6 upcoming IRP.
- 7 • Lee Shaver — Union of Concerned Scientists. Mr. Shaver is a Senior
8 Energy Analyst at the Union of Concerned Scientists. His direct testimony
9 addresses two subjects. First, he evaluates the clean energy and emissions
10 implications of DTE’s proposed resource plan under the CCAA, including
11 whether DTE’s approach supports the Customer’s goal that its facility be
12 served by 100% renewable energy. Second, he evaluates the grid
13 reliability risks posed by the proposed facility and recommends specific
14 technical requirements—including operational ramp rate limits and
15 voltage and frequency ride-through standards consistent with MISO’s
16 current proposed requirements and NERC’s guidance—as conditions of
17 interconnection approval.
- 18 • Dr. Laura S. Sherman — Michigan EIBC and IEI. Dr. Sherman is the
19 President of the Michigan EIBC and IEI. Her direct testimony addresses
20 (i) the resource ownership structure proposed in the contracts and the
21 appropriate role for third-party owned resources, (ii) the availability of
22 customer-sited resources and Virtual Power Plants as cost-effective

alternatives or complements, and (iii) the design of the financial incentive for Zonal Resource Credits brought by the Customer.

IV. OVERVIEW OF THE CASE

Q: What are the criteria or standards that the Commission must apply to evaluate the Company's Special Contracts?

A: The Commission must find that contracts at issue are just and reasonable and in the public interest. The Commission has interpreted these standards in the context of large-load customer arrangements through its November 6, 2025 final order in Case No. U-21859 (Consumers Energy large-load Rate GPD case) and its December 18, 2025 order in Case No. U-21990. This framework requires that costs caused by a new large load be paid by that customer rather than socialized to other ratepayers, and that the utility affirmatively demonstrate the absence of cost-shifting before the customer takes service.

I am not offering a legal opinion. My understanding, for purposes of this testimony, is that the Commission's inquiry includes whether the proposed special contracts are just and reasonable and in the public interest, and that this evaluation must determine whether other customers are protected from costs caused by the Customer. Additionally, DTE's application relies on MCL 460.6a(3) for the proposition that approval for the Special Contracts could have been granted without notice or hearing because the requested approval will not increase the cost of service to customers, although DTE nevertheless filed this application as a contested case. DTE itself invokes the U-21859 framework. Exhibit A-19 is offered to show that costs caused by the customer are not being paid for by other customers—the demonstration U-21859 requires. For these reasons, I understand the Commission's U-21859 framework to be directly relevant to the cost-causation and no-

1 cost-shift showing DTE offers here as basis for the Commission to approve its Special
2 Contracts. My testimony addresses whether DTE’s evidentiary showing is sufficient, as a
3 matter of regulatory policy and analysis, to support the no-cost-shift finding DTE asks the
4 Commission to make.

5 **Q: How did the Commission frame the cost-causation and no-cost-shift principles in U-**
6 **21859?**

7 A: The Commission articulated four points directly relevant here:

- 8 • New large loads must “fully pay for the costs needed to serve them,”
9 avoiding cross-subsidization and stranded assets;⁶
- 10 • Traditional cost-of-service socialization of large-load costs at this scale is
11 “unacceptable” given the magnitude and unprecedented character of the
12 load;⁷
- 13 • “Customers are responsible for the costs they impose”—a cost-causation
14 test, not an averaged or net-benefit test;⁸and
- 15 • Before a large load customer takes service, the utility must demonstrate
16 that costs caused by the interconnecting customer are not being paid for by
17 other customers; for special contracts, the showing is that the full costs of
18 serving the customer are paid by that customer.⁹

⁶ Commission Final Order, Case No. U-21859, at 103 (Nov. 6, 2025) (“U-21859 Final Order”).

⁷ *Id.* at 116.

⁸ *Id.*

⁹ *Id.* at 116.

V. THE COST-OF-SERVICE STUDY COMPARISON IS METHODOLOGICALLY REASONABLE, BUT IS ONLY ONE COMPONENT AND, ON ITS OWN, DOES NOT FULLY RESOLVE THE NO-COST-SHIFT QUESTION

A. The Cost-of-Service Study Comparison Is One Component of DTE's Net-Benefit Calculation

Q: In plain terms, what is a cost-of-service comparison and why does DTE utilize it here?

A: A cost-of-service study allocates the utility's revenue requirement across customer classes based on the costs each class is found to cause. DTE's comparison takes the cost-of-service study from its last approved rate case (U-21534), re-runs it with the new large load layered into the Rate D11 class, and reports how the resulting class-level revenue-and-cost picture would shift. The purpose is to show—at the class-allocation level—whether other customers would bear costs caused by the Customer. The cost-of-service study comparison is one component of DTE's broader Affordability Benefit calculation in Exhibit A-19 and is most useful when combined with the rest of that calculation and within the cost-causation framework of U-21859 and U-21990.

Q: How does DTE identify the cost impact of the Customer load on other customers?

A: DTE's approach has two parts. The first is a with-and-without cost-of-service comparison in Exhibit A-20: DTE runs its COSS from the last general rate case (Case No. U-21534, as adjusted) twice—once without the data center and once with it—and reports the change in each class's revenue requirement.¹⁰ That comparison is the source of the Base Sales Benefit line of approximately \$(4.85) billion over 2028–2047 in Exhibit A-19.¹¹ The second part

¹⁰ Direct Testimony of Aaron Willis on behalf of DTE Electric Company ("Willis Direct"), Case No. U-22058, at 8.

¹¹ Exhibit A-19, line 2, column (v).

1 is a set of additional cost and benefit lines that DTE layers on top of the COSS comparison
2 in Exhibit A-19: the proxy Combined Cycle Gas Turbine (“CCGT”) and Carbon Capture
3 and Storage (“CCS”) revenue requirements (lines 8 and 10), the storage pull-ahead benefit
4 (line 12), the incremental PSCR (line 4), and other items.¹² The full \$1.7 billion
5 Affordability Benefit reported on Exhibit A-19, line 14, column (v), is the arithmetic sum
6 of the COSS-derived sales benefit and these layered cost and benefit lines.¹³

7 **Q: Is the methodology of running the cost-of-service study with and without the**
8 **customer load a reasonable approach?**

9 A: A with-and-without comparison is a simple analytical tool for comparing two scenarios,
10 and re-running the cost-of-service study to isolate the class-level effect of adding a large
11 load is a reasonable way to begin the analysis. However, the comparison captures only the
12 customer’s incremental revenues and incremental base power-supply expenses against the
13 existing fixed-cost allocators.¹⁴ It does not include all of the additional costs and benefits
14 that DTE attributes to serving the Customer. DTE acknowledges that those additional
15 categories are accounted for separately, outside the cost-of-service study comparison, in
16 Exhibit A-19.¹⁵ In effect, the cost-of-service study comparison reflects only the revenue-
17 allocation effect of bringing the Customer onto the system. The additional costs of
18 generation, CCS, storage, PSCR, and O&M are layered in separately in the broader Exhibit
19 A-19 analysis.

¹² Willis Direct at 5–7.

¹³ *Id.* at 7; Exhibit A-19, line 14, source column: “Sum of proceeding rows.”.

¹⁴ Willis Direct at 8

¹⁵ *Id.* (“No. Additional rate base costs, benefits, and other costs are identified separately in Exhibit A-19.”).

B. What the Cost-of-Service Study Comparison Shows for the Residential Class

Q: What does DTE’s cost-of-service study comparison reveal about the residential class?

A: A notable reduction in costs allocated to the residential class. Although the Customer’s load results in an increase in total system costs, residential ratepayers are allocated less costs because an even greater amount is shifted from the residential class to the D11 Class, including the new Customer. Exhibit A-20 (“Customer Study Results” tab) shows the results of DTE witness Willis’s with-and-without cost-of-service comparison. Drawing on the class-level revenue requirement outputs in Exhibit A-20,¹⁶ adding the Customer reduces the residential class revenue requirement by approximately \$352 million when comparing the adjusted baseline to the Customer data center case. Of that total, approximately \$328 million falls on the production side¹⁷ and approximately \$24 million on the distribution side¹⁸—nearly all of the reduction is production-driven.

The mechanism behind the production reduction is the shift in coincident-peak allocators. As DTE witness Willis explains, his analysis updated the load schedules “such that the data center’s load is reflected in the production and distribution allocators.”¹⁹ Production costs—including base-rate transmission costs, which are allocated to classes based on the twelve-month coincident peak—are reassigned when a new large load changes each class’s share of system peak. Because the Customer is a 24/7, high-load-factor load that contributes substantially to DTE’s coincident peak, adding it increases the D11 class’s share of production costs and correspondingly reduces the residential class’s

¹⁶ Exhibit F1.1, cell E61 for residential production; Exhibit F1.2, cell E55 for residential distribution.

¹⁷ Exhibit A-20 (Exhibit F1.1, cell E61).

¹⁸ Exhibit A-20, Exhibit F1.2, cell E55)

¹⁹ Willis Direct at 8–9.

1 share—from approximately 44.5 percent to approximately 32.5 percent.²⁰ That 12-
2 percentage-point shift in the residential class’s production allocation is the primary driver
3 of the \$328 million production reduction, and it is the central mechanism behind DTE’s
4 asserted Affordability Benefit.

5 It bears emphasis that this redistribution is a reallocation of fixed cost
6 responsibility, not a reduction in total system cost. At the system level, Exhibit A-20²¹
7 shows total revenue requirement rising by approximately \$264 million when the Customer
8 is added. The residential reduction is a shift of fixed production costs—including
9 transmission—onto a new payer, the Customer, through the coincident-peak allocation
10 mechanism.

11 **Q: What would be the impact on residential customer rates from this reduced revenue**
12 **requirement?**

13 A: If the \$352 million reduction in residential revenue requirement identified in Exhibit A-20
14 were passed through in a general rate case, it would put meaningful downward pressure on
15 residential rates. As a rough illustration, a \$352 million reduction in residential revenue
16 requirement against an adjusted residential base of approximately \$3.1 billion²² represents
17 a reduction of approximately 11 percent—a significant rate benefit if fully realized.

18 However, this figure reflects only the base-rate COSS comparison in Exhibit A-20,
19 which, as DTE witness Willis explains, excludes additional rate base costs and other cost
20 categories that are identified separately in Exhibit A-19.²³ As I describe in the following
21 section, Exhibit A-19 layers additional cost lines on top of the Exhibit A-20 COSS result—

²⁰ Exhibit A-20 (Exhibit F1.1, cell E61 vs. U-21534 Order COSS).

²¹ See Base Sales Benefit tab, cells D48/H48 for production, E48/I48 for distribution.

²² Exhibit A-20 (Exhibit F1.1).

²³ Will Direct at 8.

1 most significantly, the proxy combined-cycle gas turbine and carbon capture and
2 sequestration revenue requirements, totaling approximately \$6.6 billion over the contract
3 term. Those costs would offset the residential rate reduction the COSS comparison
4 suggests. The net effect on residential rates over the contract period therefore depends on
5 how those additional costs and benefits are ultimately allocated across rate classes in future
6 rate cases—a determination that will be made in the IRP and in subsequent general rate
7 cases, not in this proceeding. The \$352 million residential COSS reduction should therefore
8 be understood as indicating the direction and potential magnitude of the base-rate effect,
9 not as a complete picture of what residential customers will ultimately pay or save.

10 ***C. Considerations That Affect How Much Impact the COSS Comparison Can***
11 ***Have on the No-Cost-Shift Determination***

12 **Q: Are there considerations that limit how much weight the Commission can place on**
13 **the COSS comparison alone?**

14 **A:** Yes, and several are worth examining in detail. Each impacts how much the comparison
15 can be read as a demonstration that other customers are held harmless from the costs the
16 Customer's load causes, not to whether running the comparison was reasonable.

- 17 • **Near-zero incremental rate base.** DTE's with/without COSS comparison
18 shows essentially no change in net rate base, even though the expected
19 customer load is 1,000 MW at a 90 percent load factor. That does not
20 make the COSS comparison unreasonable, but it confirms that the COSS
21 comparison should not be read as a full incremental-cost study. DTE itself
22 accounts for additional generation, CCS, storage, PSCR, O&M, and
23 transmission-related impacts outside that comparison in Exhibit A-19 and

1 related exhibits. The question is therefore whether the full set of separately
2 modeled costs, benefits, offsets, and backstop provisions is sufficient to
3 demonstrate that other customers are protected from costs caused by the
4 Customer's new load.

5 • **Averaged, embedded allocation versus direct cost causation.** The

6 COSS allocates system-average embedded costs across classes. The
7 Commission's decision in U-21859 emphasized that for large loads, cost
8 causation should be tested directly, not socialized through averaged
9 allocation.²⁴ The COSS comparison shows what averaged allocation
10 produces; it does not, on its own, test cost causation.

11 • **Coincident-peak allocator and high-load-factor service.** A coincident-

12 peak demand allocator pools generation cost across the system peak. A
13 24/7, high-load-factor data center may present cost-causation issues that
14 are not fully captured by demand allocators, depending on how resource
15 additions are driven by energy, capacity, and reliability needs. The class-
16 level result is therefore sensitive to the allocator design and should be
17 considered together with the direct incremental resource analysis.

18 • **Reallocation versus system savings.** At the system level, DTE's

19 comparison shows total revenue requirement rising by approximately \$264
20 million when the customer is added. The residential reduction is a shift of
21 fixed costs onto a new payer (the Customer), not a system-wide reduction
22 in overall cost.

²⁴ U-21859 Final Order at 116.

D. The COSS Comparison Alone Does Not Fully Resolve the No-Cost-Shift Question

Q: Does the COSS comparison alone fully establish that costs caused by the Customer are not being paid for by other customers?

A: Not on its own. The methodology is reasonable as far as it goes, and the comparison identifies a potential, meaningful class-level redistribution worth examining. But the considerations above—together with the broader calculation in Exhibit A-19 that layers additional cost lines on top of the COSS-derived sales benefit, which I address in the following section—mean the Commission should not treat the COSS comparison, standing alone, as a complete demonstration that no costs of serving the Customer are shifted to other ratepayers. In addition, as I mentioned above, the \$352 million reduction in residential revenue requirement identified in Exhibit A-20 must be passed through in general rate case for residential ratepayers to receive the benefits in terms of downward pressure on rates. It cannot be adjudicated fully in this proceeding.

VI. THE ~\$1.7 BILLION AFFORDABILITY BENEFIT ESTIMATE IS INFORMATIVE BUT NOT SUFFICIENT, WITHOUT ENFORCEABLE VERIFICATION AND TRUE-UP CONDITIONS, TO SUPPORT A DURABLE FINDING OF NO COST SHIFTING

A. The Affordability Benefit Estimate and How It Is Calculated

Q: What is the \$1.7 billion Affordability Benefit figure and where does it appear?

A: DTE’s application and testimony asserts that the “Customer’s new load will provide a net benefit across all of its customer classes.”²⁵ Specifically, reports DTE offers

²⁵ Application at 5.

1 \$(1,697,471,000) as the net benefit to other customers over the period of 2028 to 2047.²⁶

2 The figure is the arithmetic sum of the following six line items, all in thousands of dollars

3 and aggregated as nominal annual amounts across 20 years:

- 4 • Base Sales Benefit (line 2): \$(4,850,957) — sourced from Willis Exhibit
- 5 A-20.
- 6 • Incremental Power Supply Cost Recovery (line 4): \$(2,305,056) —
- 7 sourced from Burgdorf Exhibit A-13.
- 8 • Other Non-F&PP O&M (line 6): \$15,443 — sourced from Burgdorf
- 9 Exhibit A-6.
- 10 • Proxy Combined Cycle Gas Turbine Revenue Requirement (line 8):
- 11 \$4,174,534 — sourced from Burgdorf Exhibit A-5.
- 12 • Carbon Capture and Sequestration (“CCS”) Revenue Requirement (line
- 13 10): \$2,430,159 — sourced from Burgdorf Exhibit A-5.
- 14 • Storage Pull-Ahead Benefit (line 12): \$(1,161,594) — sourced from
- 15 Burgdorf Exhibit A-5.

16 The “Total (Benefit) / Cost to Customers” on line 14 is described in the exhibit’s

17 own source column as the “Sum of proceeding rows.” Line 16 is labeled “Cumulative

18 (Benefit) / Cost.” These are both arithmetic sums, not discounted values.

19 ***B. The \$1.7 Billion Affordability Benefit Is a Nominal Sum, Not a Present Value***

20 **Q: Is the \$1.7 billion a present value?**

21 A: No. Exhibit A-19 does not provide a discount factor or NPV column. While the DTE

22 witnesses do not characterize the \$1.7 billion as a net present value, neither do they

²⁶ Willis Direct at 7; Exhibit A-19 at line 14.

1 characterize it as a nominal sum. It is offered simply as the “\$1.7 billion benefit ... during
2 the term of the Contracts.”²⁷ As I show next, the figure is in fact a 20-year arithmetic sum
3 of nominal annual values.

4 **Q: How is that confirmed across the underlying lines?**

5 A: All four of the major lines are confirmed to be nominal, undiscounted dollars on the public
6 record. Each line’s annual profile is incompatible with a present-valued stream:

- 7 • Base Sales Benefit (Exhibit A-19, line 2). Annual values grow every year,
8 from \$(92,787) thousand in 2028 to \$(284,684) thousand in 2047,
9 consistent with the 1.5 percent per year escalation Willis describes.²⁸ A
10 present-valued stream discounted at any reasonable rate would shrink, not
11 grow. Growth is the signature of nominal escalation. Two related
12 assumptions are embedded in this profile and warrant separate attention:
13 first, the calculation assumes effectively perpetual revenue growth from
14 the Customer’s load across the 20-year window, without modeled
15 disruption from contract renegotiation, load variability, or early
16 termination; and second, the calculation assumes Customer load at
17 approximately a 90 percent load factor for the full 20-year term, rather
18 than at the contractual minimum billing demand floor that defines the
19 Customer’s downside obligation. Both assumptions contribute to the
20 asserted Affordability Benefit number and are revisited in subsection I
21 below.

²⁷ Foley Direct at 8, 37.

²⁸ Willis Direct at 9.

- 1 • Incremental Power Supply Cost Recovery (“PSCR”) (Exhibit A-19, line
2 4). Exhibit A-13 expresses the PSCR delta in mills per kWh, computed as
3 the difference between Exhibit A-11 (Customer datacenter case) and
4 Exhibit A-12 (Base Case). A per-unit annual rate cannot be a present
5 value; it is applied to each year’s sales to produce annual nominal dollars.
- 6 • Proxy CCGT Revenue Requirement (Exhibit A-19, line 8). The line falls
7 by a near-constant \$7.2 to \$7.7 million each year—from \$328,325
8 thousand in 2033 to \$227,500 thousand in 2047. That arithmetic, near-
9 constant decline is the signature of a standard depreciation-driven revenue
10 requirement (return on a declining depreciable base, with straight-line
11 depreciation expense). A present-valued stream would show a constant-
12 percentage decline of roughly six percent per year layered on top of that
13 pattern.
- 14 • CCS Revenue Requirement (Exhibit A-19, line 10). The structure parallels
15 the CCGT line—declining allowable return on a depreciating base—and is
16 confirmed against Burgdorf Exhibit A-5.

17 **Q: What does the proper present-value treatment look like?**

18 **A:** At a 7 percent discount rate to 2028, the present-value equivalent of the Affordability
19 Benefit (Exhibit A-19 line 14) is approximately \$984 million—a reduction of roughly 42
20 percent from the \$1.7 billion estimate on the discounting question alone. If the storage pull-
21 ahead benefit is also removed (a sensitivity I address below in subsection F), the present
22 value drops further, to approximately \$531 million.

1 ***C. Period-by-Period: DTE’s Own Exhibit Shows Net Costs in 2035–2038***

2 **Q: Does DTE’s estimates show net benefits to other customers in every year?**

3 A: No. Exhibit A-19, line 14, shows positive amounts—modeled costs rather than benefits to
4 other customers—of \$42,235,000 in 2035; \$48,558,000 in 2036; \$55,290,000 in 2037; and
5 \$25,988,000 in 2038, totaling approximately \$172 million across those four years. The 20-
6 year netting approach obscures that annual profile.

7 At minimum, the existence of positive annual cost years demonstrates that the
8 Commission should address whether its no-cost-shift requirement is satisfied annually,
9 cumulatively, or through some defined true-up period.

10 ***D. The Proxy CCGT-CCS Placeholder Does Double Duty and Is Itself a Contested***
11 ***Portfolio Choice***

12 **Q: Why does the proxy CCGT-CCS matter to the benefit calculation?**

13 A: The hypothetical 727 MW gas-with-carbon-capture plant assumed online in 2033 drives
14 approximately \$6.6 billion of cost in the analysis²⁹—and simultaneously provides the
15 resource-adequacy justification underlying the cost lines through DTE witness Brooks’s
16 SERVM modeling.³⁰ Whether the proxy plant is required to meet the 0.1 LOLE constraint
17 given the resources the CCAA brings to the system is addressed in the direct testimony of
18 MEI/CEO witness Hotaling.

²⁹ \$4.17 billion CCGT (line 8) plus \$2.43 billion CCS (line 10).

³⁰ Direct Testimony of Justin J.W. Brooks on behalf of DTE Electric Company Direct, Case No. U-22058, at 8–10 (“Brooks Direct”); Exhibit A-4.

1 DTE witness Burgdorf describes the plant as a placeholder the 2026 IRP may not
2 adopt.³¹ No alternative portfolio of storage, renewables, and demand response was tested
3 against the same reliability target.

4 The customer-benefit calculation therefore depends materially on a proxy resource
5 decision that DTE says will be revisited in the 2026 IRP. The Commission is being asked
6 to approve specials contracts here on the basis of a resource decision it will make later, in
7 the IRP.

8 **Q: Does DTE acknowledge that the proxy plant is needed because of the Customer?**

9 A: Yes, in the structure of the analysis if not explicitly in the framing.³² Burgdorf's Table 1
10 shows the proxy CCGT-CCS only in the "Customer datacenter case."³³ This resource is
11 added in 2033, when the Customer's interim capacity contributions (Demand Response
12 250 MW, ZRC Contract 300 MW) drop out. The plant does not appear in the Base Case.

13 Yet DTE witness Willis describes the proxy plant's revenue requirement as a cost
14 imposed on other customers: "Future generation resources (modeled here using a
15 Combined Cycle Gas Turbine (CCGT) with Carbon Capture and Sequestration (CCS) as a
16 proxy) introduce additional costs."³⁴ DTE's stated justification is that the plant will retain
17 value to other customers after the Customer's contract ends in 2047,³⁵ with approximately
18 \$647 million NPV in market revenue assumed to offset some of the post-2047 revenue
19 requirement, and approximately 74 percent of the plant's NPV "paid off" through the
20 contract term.³⁶ DTE's post-2047 analysis therefore asks other customers to rely on

³¹ Direct Testimony of Shawn D. Burgdorf on behalf of DTE Electric Company Direct, Case No. U-22058, at 13 ("Burgdorf Direct").

³² Direct Testimony of Chelsea Hotaling on behalf of the MEI/CEI, Case No. U-22058, at 12-13 ("Hotaling Direct").

³³ Burgdorf Direct at 11.

³⁴ Willis Direct at 5.

³⁵ Burgdorf Direct at 13.

³⁶ Burgdorf Direct at 13-14; Exhibit A-15 at lines 21-22.

1 residual value and avoided future resource costs for a proxy asset that appears only in the
2 Customer case. That is a material assumption that the Commission should determine as
3 requiring verification in the IRP and through any affordability backstop.

4 ***E. The CCS Cost Line Embeds a Federal Tax Credit Assumption That Carries***
5 ***Policy and Eligibility Risk***

6 **Q: What does the 2047 spike in the CCS line reveal?**

7 A: The CCS revenue requirement falls steadily from 2035 through 2046 and then jumps from
8 \$157,651,000 in 2046 to \$232,674,000 in 2047—an increase of approximately \$75
9 million.³⁷ The jump corresponds to the end of the 12-year federal 45Q carbon-capture tax
10 credit window. The CCS revenue requirement DTE shows during 2035–2046 is therefore
11 net of approximately \$75 million per year—on the order of \$0.9 billion or more over the
12 credit window—of assumed federal tax credit.

13 **Q: Why is that a problem for the benefit case?**

14 A: Three reasons. First, 45Q is a federal tax credit whose full value depends on continuing
15 federal law and on project-specific eligibility, including prevailing-wage, apprenticeship,
16 and sequestration requirements. If the credit is reduced, repealed, or the project does not
17 qualify, the CCS cost to ratepayers rises and the net benefit shrinks. Second, the 20-year
18 analysis window captures all 12 subsidized years but only one un-subsidized year (2047);
19 the remainder of the plant's un-credited life sits past 2047 in Exhibit A-15, a separate
20 calculation that nets to a small benefit. That makes the treatment of post-2047 residual
21 costs important to the no-cost-shift analysis. Third, layering a 12-year federal-credit

³⁷ Exhibit A-19 at line 10.

1 assumption onto a hypothetical plant the Commission has not approved compounds the
2 uncertainty.

3 More generally, carbon capture and storage on natural-gas combined-cycle units
4 raises technology, cost, and performance risks that should be examined before it is relied
5 upon as a major component of the no-cost-shift finding that the Commission must make
6 here. DTE's plan to rely on CCS-equipped CCGTs in this timeframe therefore warrant
7 careful review in the IRP and in any back-end affordability benefit verification process.

8 ***F. Storage Pull-Ahead: Deferral, Not Permanent Avoidance***

9 **Q: Is the \$1.16 billion storage pull-ahead benefit reliable?**

10 A: The benefit reflects DTE storage builds avoided in 2035–2047 because the Customer's
11 CCAA funds up to 480 MW of storage directly.³⁸ The customer-funded storage is correctly
12 off DTE's ratepayer books. However, the "pull-ahead" framing raises an unresolved timing
13 and counterfactual issue. If the displaced DTE storage is deferred beyond the 2047 window
14 rather than permanently avoided, the true benefit may be closer to the time value of deferral
15 than to the full \$1.16 billion avoided revenue requirement that DTE books here in its
16 Affordability Benefit calculation. In addition, as discussed by MEI/CEO witness
17 Hotaling,³⁹ to the extent the CCAA-funded resources built to serve the Customer load also
18 obviate the need for DTE-built storage in the later years, the storage in those later years
19 may not have been needed to serve the ex ante (without-Customer) load, which suggests a
20 portion of the avoided-cost benefit reflects a planning assumption rather than a true
21 avoidance.

³⁸ Willis Direct at 6; Exhibit A-19 at line 12.

³⁹ Hotaling Direct at 25.

1 ***G. Transmission Cost Allocation***

2 **Q: Does DTE’s treatment of transmission costs raise an additional issue for the**
3 **Commission’s no-cost-shift review?**

4 **A:** Yes. DTE’s treatment of transmission costs spans two witnesses and two recovery
5 mechanisms, and while the analysis is structurally complete, the Commission cannot fully
6 verify it based on this record.

7 The first mechanism is the base-rate COSS. As I describe in Section V.C above,
8 DTE witness Willis updated the twelve-month coincident peak allocators in Exhibit A-20
9 to reflect the Customer’s load.⁴⁰ Because the Customer is a large, high-load-factor load that
10 contributes substantially to DTE’s coincident peak, its addition shifts base-rate
11 transmission costs—allocated by 12CP and recovered through D11 demand charges—from
12 the residential class toward the Customer’s class. That shift is embedded in the
13 approximately \$328 million reduction in residential production revenue requirement
14 identified in Exhibit A-20,⁴¹ which I discuss in Section V.C.

15 The second mechanism is the PSCR surcharge. Witness Burgdorf identifies two
16 incremental transmission impacts in the Customer datacenter case: 1) the \$308 million ITC
17 network upgrade recovered through MISO Schedule 9, and 2) increases in other MISO
18 schedule charges driven by the Customer’s load.⁴² Together these produce a \$91 million
19 increase in 2029 transmission expense—\$889 million in the Customer datacenter case
20 versus \$798 million in the base case.⁴³ Therefore, witness Burgdorf’s “no adverse impact”
21 showing—transmission unit cost falling from \$0.0148 to \$0.0144 per kWh—reflects

⁴⁰ Willis Direct at 8–9.

⁴¹ Exhibit A-20 (Exhibit F1.1, cell E61).

⁴² Burgdorf Direct at 19–20.

⁴³ *Id.* at 20; Exhibit A-9 at line 30 versus Exhibit A-7 at line 30.

1 spreading that \$91 million increment across the Customer’s additional load volume through
2 the uniform PSCR surcharge.⁴⁴

3 The problem is not that either piece is missing. Taken together, Willis’s COSS
4 captures the base-rate 12CP transmission shift, and Burgdorf’s PSCR model captures the
5 incremental surcharge-side transmission costs. What the record does not show is whether
6 the two analyses fit together without gap or overlap. Specifically, the record does not
7 demonstrate how much of the \$91 million increase in 2029 transmission expense reflects
8 the ITC capital recovery through Schedule 9 versus the increase in other MISO schedule
9 charges driven by the Customer’s coincident peak contribution, which MISO itself
10 allocates based on peak demand, not energy volume. Nor does the record confirm that the
11 12CP allocator update in Exhibit A-20 and the PSCR surcharge model in Exhibit A-13 are
12 properly separated so that the same transmission costs are not credited in both analyses.
13 The Commission should therefore require DTE to reconcile these two components—base-
14 rate COSS transmission and incremental PSCR transmission—in the next rate case and in
15 PSCR plan and reconciliation proceedings, as part of the backstop reporting framework I
16 describe in Section VII.

17 **Q: How did the Company develop the transmission expense figures underlying both the**
18 **cost-of-service comparison and the PSCR surcharge calculation, and can those**
19 **figures be verified on this record?**

20 **A:** For the base case, witness Burgdorf states that transmission costs are “projected based on
21 a forecast of MISO charge types associated with transmission for the International
22 Transmission Company (ITC) pricing zone” and are “consistent with the costs forecasted

⁴⁴ Burgdorf Direct at 20–21.

1 in the 2026 PSCR Plan plus estimated costs associated with the first data center
2 customer.”⁴⁵ For the Customer data center case, the \$308 million ITC network upgrade
3 cost is drawn from “initial estimates provided by the Company’s transmission provider,”⁴⁶
4 meaning ITC’s own preliminary projection, not a final cost determination. The increase in
5 other MISO schedule charges—the remainder of the \$91 million 2029 transmission
6 increment—is a modeled forecast of how DTE’s MISO allocations would change based on
7 the Customer’s projected peak demand and energy use. However, Burgdorf does not
8 describe the specific methodology or inputs used to derive that allocation change.⁴⁷ In
9 Willis’s analysis side, the 12CP allocator update in Exhibit A-20 reflects the Customer’s
10 projected coincident peak contribution, which itself rests on the same load assumptions
11 underlying the rest of the analysis.⁴⁸

12 Neither the ITC upgrade cost nor the MISO schedule charge projections can be
13 verified on this record. The \$308 million figure is an initial estimate that will be refined as
14 ITC’s project scope is finalized and approved through MISO’s processes; actual costs
15 could be higher or lower. The MISO schedule charge increases are forward projections
16 dependent on MISO tariff rates, DTE’s load, and system conditions that will only be known
17 as the Customer’s load comes online and MISO settles actual charges. These are not
18 criticisms of DTE’s methodology—forward cost estimation of this kind is inherent to any
19 ex ante analysis. But they are additional sources of uncertainty that compound the structural
20 verification gap I describe above. Actual transmission costs—both the ITC upgrade
21 recovery through Schedule 9 and the MISO schedule charge changes—should be tracked

⁴⁵ Burgdorf Direct at 18.

⁴⁶ *Id.* at 19–20.

⁴⁷ *Id.*

⁴⁸ Willis Direct at 8–9.

1 and reported as part of the affordability backstop framework I describe in Section VII, so
2 that the Commission can determine in future rate case and PSCR proceedings whether other
3 customers have in fact been held harmless from the transmission costs the Customer's load
4 causes.

5 **Q: Have other state commissions recently addressed the transmission cost-shifting risk**
6 **that large data-center loads can create?**

7 A: Yes. The risk that large data-center loads can shift transmission to other ratepayers has
8 been surfaced and addressed in active dockets in other jurisdictions, and the protections
9 those commissions have adopted are relevant context for the Commission's no-cost-shift
10 review here. The most directly applicable recent decision is the Wisconsin Public Service
11 Commission's May 21, 2026 final decision on Wisconsin Electric Power Company's
12 ("WEPCO") proposed Very Large Customer ("VLC") tariff for data centers. In that case,
13 the Commission identified "the potential for cost shifting between VLCs and non-
14 participating customers associated with transmission facilities needed to serve the VLC."
15 The Wisconsin Commission approved a modified version of WEPCO's proposal, but
16 materially strengthened the cost-shift protections related to transmission costs, including:
17 (1) imposing a minimum-billing-demand transmission charge that requires data-center
18 customers to pay transmission cost responsibility based on their projected demand or actual
19 demand, whichever is higher, to offset the risk that already-under-construction
20 transmission infrastructure built for the new load would otherwise be subsidized by other
21 ratepayers; and (2) requiring WEPCO to report all transmission revenues from VLCs as

1 well as annual revenue requirement impacts caused by transmission facilities required to
2 serve VLCs.⁴⁹

3 The Wisconsin order is not controlling here, but it provides useful context to the
4 transmission cost-shift risk I discuss above. The WEPCO outcome demonstrates that the
5 transmission cost-shift risk is real enough that another state commission moving through a
6 similar proceeding has built specific, durable protections into the tariff, including binding
7 reporting obligations that map directly onto the conditions and affordability-backstop
8 elements I recommend later in this testimony.

9 Similarly, the Pennsylvania Public Utilities Commission issued a final “Large Load
10 Model Tariff Framework” in May, which provides extensive protections against cost shifts
11 arising from transmission costs.⁵⁰ The Pennsylvania Commission found that “cost
12 allocation must adapt to shield ratepayers from socialization of costs that are properly
13 attributed to Large Load Customers.” To accomplish that objective, the Pennsylvania
14 Commission’s model tariff requires large loads to pay 100% of all “but-for” transmission
15 costs upfront, ensuring that other ratepayers do not subsidize any costs that large loads
16 directly cause. While that approach may not be workable in the instant case, it demonstrates
17 the type of aggressive measures other states are adopting to prevent cost shifts.

18 **Q: What condition should the Commission adopt regarding transmission costs?**

19 **A:** The Commission should require DTE to include transmission costs in the same back-end
20 verification and affordability-backstop framework I recommend for the rest of the contract.

21 At a minimum, DTE should be required to report: (1) the actual ITC transmission upgrade

⁴⁹ Wisconsin Public Service Commission, Docket 6630 TE 113, Final Order at 26–27, 49 (May 21, 2026).

⁵⁰ Pennsylvania Public Utilities Commission, Docket M-2025-3054271, Final Order (May 12, 2026), available at <https://www.puc.pa.gov/pdocs/1929842.pdf>.

1 costs associated with serving the Customer; (2) how those costs are recovered through
2 MISO schedules and reflected in PSCR; (3) the portion of those costs paid by the customer
3 through D11 and PSCR charges; (4) the effect of the Customer's load on transmission
4 billing determinants and unit costs; and (5) whether, after accounting for both incremental
5 costs and revenues, other customers are held harmless. If actual transmission-related costs
6 exceed the amounts assumed in Exhibit A-19, or if the allocation of those costs produces a
7 net cost to other customers, the affordability backstop should require a true-up from the
8 Customer rather than leaving the difference with other ratepayers.

9 ***H. Cost-Effectiveness Opportunities the Analysis Does Not Reflect***

10 **Q: Assuming it is accurate, does DTE's estimated \$1.7 billion Affordability Benefit**
11 **demonstrate its proposals are cost-effective?**

12 A: No. DTE's analysis assumes a particular resource mix to serve the customer load—
13 anchored on company-owned generation supplemented by a hypothetical proxy plant. As
14 MEI/CEO witness Sherman testifies, DTE's Exhibit A-19 does not reflect, and therefore
15 does not quantify, the effect of cost-effective alternatives that may be available, including:
16 third-party-funded resources, the resource ownership structure, customer-side flexibility,
17 and Virtual Power Plants. Each of those tools could reduce the cost of serving the Customer
18 load below the level DTE has modeled. If DTE adopted them, the cost-side lines in Exhibit
19 A-19 (the proxy CCGT-CCS in particular, but also the PSCR line) could be smaller, and
20 the net benefit to other customers could be larger.

21 **Q: Why does that matter for the Commission's decision here?**

22 A: The Commission's evaluation of the reasonableness of these contracts and its public-
23 interest inquiry should include whether the proposed contracts represent a cost-effective

1 approach to serving the Customer’s load. The \$1.7 billion Affordability Benefit estimate
2 as filed reflects neither the costs DTE would incur under an optimized procurement nor the
3 benefits available to other customers under an optimized resource plan. The analysis
4 therefore may overstate the costs other customers would bear under best-available
5 alternatives and may understate the achievable benefit. In addition, my testimony identifies
6 several aspects of the Affordability Benefit calculation that are subject to significant
7 uncertainty or hinge on decisions that will be made in the future in other proceedings. The
8 remedy is to require, as a condition of approval, that DTE evaluate and pursue cost-
9 effective options such as those MEI/CEO witness Sherman identifies, and to require an ex
10 post demonstration that those opportunities have been considered and pursued where cost-
11 effective.

12 **Q: Are there other components of DTE’s proposal that affect whether other customers**
13 **are paying the costs of serving the Customer?**

14 A: Yes. As MEI/CEO witness Sherman explains, the CCAA requires the Customer to transfer
15 300 MW of Zonal Resource Credits to the Company at no cost.⁵¹ DTE proposes that the
16 Company receive an additional payment from the Customer—calculated as a financial
17 adder analogous to the Financial Compensation Mechanism authorized under PA 235 of
18 2023—and record that payment as non-refundable income benefiting shareholders.
19 MEI/CEO Witness Sherman recommends the Commission reject this financial adder on
20 the grounds that there is no lost earnings opportunity or imputed debt associated with
21 receiving ZRCs at no cost. To the extent the Commission approves some form of financial
22 adder, it should be treated as a cost offset that reduces revenue requirements for all

⁵¹ Direct Testimony of Dr. Laura S. Sherman on behalf of the MEI/CEI, Case No. U-22058, at 25 (“Sherman Direct”).

1 ratepayers, not as non-refundable shareholder income. The treatment of this payment is
2 directly relevant to the no-cost-shift question: income retained by shareholders from a
3 transaction that reduces the Company’s resource adequacy obligations is income that
4 should instead flow to ratepayers as a cost reduction.

5 ***I. The Underlying EnCompass and SERVVM Modeling Carries Open Assumption***
6 ***Questions***

7 **Q: Are the assumptions feeding the underlying production-cost and reliability**
8 **modeling fully verifiable and reasonable on the record?**

9 A: Not entirely. The PSCR benefit (Exhibit A-19, line 4) flows at least partially from DTE’s
10 EnCompass production-cost modeling. The proxy plant resource-adequacy “need”—and
11 through it the CCGT, CCS, and storage lines—flows from DTE witness Brooks’s SERVVM
12 reliability modeling.⁵² As MEI/CEO witness Hotaling explains, several of the cost and
13 benefit categories that rest on DTE’s EnCompass modeling—the proxy CCGT-CCS
14 revenue requirement, the MISO market purchases and sales, and the storage pull-ahead
15 benefit—depend on modeling assumptions that are likely to change when DTE performs
16 updated capacity-expansion modeling in its next IRP, and so cannot be treated as fixed on
17 this record. The SERVVM modeling is similarly central to the cost lines: every dollar of
18 CCGT, CCS, and storage in Exhibit A-19 rests on the SERVVM “need” finding. MEI/CEO
19 witness Hotaling’s own independent SERVVM modeling confirms that a resource-adequacy
20 need does arise in 2033, but the specific resources used to meet that need—and therefore
21 the magnitude of the associated cost lines—remain to be determined in the IRP rather than

⁵² Brooks Direct at 7–10; Exhibit A-4.

1 on this record. The net-benefit estimate built on top of EnCompass and SERVVM inherits
2 the uncertainty in both.

3 ***J. Conclusion on the Affordability Benefit Estimate***

4 **Q: What is your overall assessment of DTE's \$1.7 billion estimate?**

5 A: The figure is built on DTE's own legitimate modeling tools, and the basic structure of the
6 calculation is reasonable. At the same time, the calculation carries meaningful uncertainty
7 across several components: it is a 20-year nominal sum, not a present value; the annual
8 profile includes years in which DTE's own exhibit shows modeled net *costs* rather than
9 benefits to other customers; the cost lines depend on a hypothetical portfolio that was not
10 tested against cost-effective alternatives at the same reliability target; the resources to meet
11 the resource adequacy need in 2033 will not be selected until the IRP; the CCS line embeds
12 a federal tax credit assumption with policy and eligibility risk; the underlying EnCompass
13 and SERVVM modeling carries open assumption questions; other cost-effective
14 opportunities, such as those identified by MEI/CEO witness Sherman, are not reflected;
15 and part of the underlying production-cost modeling is not fully reproducible on the record.
16 For all of the reasons, DTE's Affordability Benefit estimate should be considered
17 preliminary and not a final determination that serving the Customer's load will indeed
18 provide that level of benefits to the Company's other ratepayers.

19 Further, the existence of some amount of Affordability Benefit, on its own, does
20 not mean that other customers do not pay some portion of the costs caused by the Customer.
21 DTE's characterization of its assumptions as conservative also does not, on its own,
22 demonstrate that the range of plausible outcomes excludes other customers paying any
23 costs caused by the Customer. The Commission should therefore not treat the single-point

1 \$1.7 billion Affordability Benefit as a complete answer to the no-cost-shift question.
2 Accordingly, Commission approval of DTE's proposal should be conditioned upon
3 systematic back-end verification I describe in the following section.

4 **VII. THE COMMISSION MUST IMPOSE BACK-END ENFORCEMENT AND**
5 **VERIFICATION TERMS TO ENSURE BENEFITS ARE REALIZED AND NO**
6 **COSTS ARE SHIFTED TO OTHER RATEPAYERS**

7 ***A. Why Ex Ante Review Is Not Enough on This Record***

8 **Q: Given the issues you have identified, can the Commission rely on the analysis that**
9 **compares the Data Center Customer case to the ex ante Base Case alone to**
10 **determine the Customer's load will not shift any costs onto other ratepayers?**

11 **A:** No. The considerations in Sections IV and V—the averaged COSS that cannot test cost
12 causation directly; the nominal-sum Affordability Benefit; the annual profile showing four
13 years of modeled net cost to other customers; the placeholder proxy plant; the federal-tax-
14 credit dependency; the open storage deferral question; the un-reconciled PSCR inputs; and
15 the cost-effective alternatives the analysis does not reflect—together prevent the
16 Commission from relying on the ex ante analysis alone as a durable demonstration that the
17 contracts are just and reasonable and in the public interest over a forward-looking, 20-year
18 proposition. The conditions and assumptions on which any approval rests must be
19 verifiable and enforceable over the life of the agreement.

1 ***B. The IRP Is the Proper Venue for the Ex Post But-For Analysis***

2 **Q: Where should the actual but-for analysis be performed?**

3 A: In DTE’s general rate cases and in its next Integrated Resource Plan. The resource
4 decisions underlying the proxy CCGT-CCS and the storage build plan will be made in the
5 IRP. Running the IRP with and without the customer load—using DTE’s actual resource
6 modeling, not the placeholder construct in this record—is the appropriate venue to
7 determine the actual incremental cost the customer load causes and to compare it to what
8 DTE forecast in Exhibit A-19. That analysis should also evaluate whether the resource-
9 ownership and customer-sited alternatives MEI/CEO witness Sherman identifies provide a
10 more cost-effective approach to meeting any incremental resource need than the Customer-
11 brought ZRC structure that DTE has assumed.

12 ***C. The Affordability Backstop Must Be Systematic, with Measurable Triggers and***
13 ***Enforceable Remedies***

14 **Q: What is DTE proposing as an “affordability backstop”?**

15 A: DTE describes the “affordability backstop” as a contractual provision in the Primary
16 Supply Agreement (“PSA”) intended to protect other customers from funding the costs to
17 serve the Customer.⁵³ The mechanism has three operative elements.

18 First, it states a goal—that the aggregate revenues DTE receives from the Customer
19 under the PSA and Related Agreements, together with avoided costs attributable to Google,
20 should outweigh the costs DTE incurs to serve the Customer’s load.

21 Second, it commits the parties to “act in good faith to ensure such combined
22 revenues and avoided costs are presented in such proceedings to the extent applicable.”⁵⁴

⁵³ Foley Direct at 19.

⁵⁴ Exhibit A-16, PSA at § 5.1.3.

1 DTE explains that the individual components of the Contracts will be addressed across
2 different regulatory proceedings—base rate effects in rate cases, incremental transmission
3 in PSCR plan and reconciliation cases, long-term generation in IRP cases, and renewable
4 additions in REP cases—and that the Company has agreed to present an aggregate view of
5 serving the Customer in those proceedings.⁵⁵

6 Third, it contains a Customer true-up. If, at any time during the 20-year term, the
7 Commission either (a) issues a ruling or order determining that the costs to serve the
8 Customer exceed the combined revenues paid or payable to the Company under the PSA
9 and Related Agreements, or (b) disallows the Company’s recovery of costs attributable to
10 serving the Customer, the Customer agrees to comply with the order and to reimburse the
11 Company for any unrecovered costs, plus interest, within ninety days. The Customer is not
12 required to reimburse for unrecovered costs caused by DTE’s gross negligence or willful
13 misconduct.⁵⁶

14 In substance, DTE’s proposed “affordability backstop” is a contract-based
15 commitment that the Customer, not other ratepayers, bears the financial consequence if the
16 Commission later finds the Contracts have not held other customers harmless. The
17 provision does not, however, specify how or when the Commission would test that
18 question, what metrics, modeling, or reporting would inform the underlying findings of
19 fact, or on what cadence such a review would occur. These shortcomings make the
20 affordability backstop insufficient to achieve its goal of ensuring other ratepayers are
21 protected from paying any costs of serving the Customer.

⁵⁵ Foley Direct at 21.

⁵⁶ (Exhibit A-16, PSA at § 5.1.3.

1 **Q: What should the affordability backstop look like?**

2 A: The Commission’s approval of the Special Contracts should be conditioned on reporting,
3 verification, and true-up procedures that make DTE’s proposed affordability backstop
4 operational and enforceable. Those procedures should contain, at minimum:

- 5 • Measurable triggers tied to the specific assumptions underlying Exhibit A-
6 19 (load factor, resource adequacy and resource selections, PSCR delta,
7 the proxy plant or its replacement, 45Q credit realization, and the storage
8 program), as well as to the resource procurement conditions this
9 Commission imposes—including the ownership split for renewable and
10 storage resources, the Customer’s ZRC obligation, and the Company’s
11 obligation to establish a Virtual Power Plant program and expand Smart
12 Savers participation using Customer-provided funding;
- 13 • A defined remedy if the triggers are breached, including a true-up or claw-
14 back to the Customer rather than other ratepayers;
- 15 • A sunset/reopener mechanism tied to the IRP cadence; and
- 16 • Reporting obligations—in this docket, the next general rate case, and the
17 next IRP—sufficient for the Commission and parties to verify
18 performance over the life of the contract.⁵⁷

19 **Q: Why does the backstop need to be systematic, and what does “systematic” mean in**
20 **this context?**

21 A: Because the uncertainty across Sections IV and V is structural, the affordability backstop
22 cannot be a one-time review or a remedy invoked only when a party files something. It

⁵⁷ Hotaling Direct at 26.

1 must be systematic, by which I mean two things. First, it must be recurring on a defined
2 cadence—most naturally the IRP cadence—with required interim reporting, including in
3 this docket, between cycles. The cost impact on other customers cannot be verified once at
4 the front end of a 20-year commitment and then assumed to hold for the life of the
5 contracts; the assumptions underlying Exhibit A-19 will need to be revisited as actual
6 experience, load, and resource decisions develop. Second, the backstop must rest on a
7 properly maintained counterfactual baseline—a “without-customer” reference case that
8 reflects what DTE’s system, costs, and resource selections would have looked like absent
9 the data center load. Without a maintained baseline, the actual cost impact on other
10 customers cannot be correctly identified, because the comparison would be to nothing in
11 particular. Pairing recurring review with a maintained without-customer baseline is what
12 allows the ex post but-for analysis to isolate the costs caused by the Customer load from
13 other system changes—which is the analytical structure contemplated by the
14 Commission’s orders in U-21859 and U-21990 and that the magnitude and term of the
15 commitment proposed by these Special Contracts require.

16 **Q: How does MEI/CEO witness Sherman’s work fit into the backstop?**

17 A: The backstop should require DTE to demonstrate that it evaluated and, where cost-
18 effective, pursued the opportunities MEI/CEO witness Sherman identifies⁵⁸—Virtual
19 Power Plants, third-party owned resources (recognizing that these resources are ultimately
20 recovered from ratepayers and so must themselves be cost-effective), and the resource
21 ownership structure—and that an ex post verification demonstrates those opportunities

⁵⁸ Sherman Direct at 46–47.

1 have been considered before any claimed benefit can be recognized as supporting a finding
2 that the contracts are in the public interest.

3 **VIII. SUMMARY AND RECOMMENDATIONS**

4 **Q: Please summarize your testimony.**

5 A: I find that additional conditions and protections on the Special Contracts are necessary to
6 ensure that the costs caused by the new 1 GW Customer load are not shifted to other
7 ratepayers, consistent with the cost-causation framework the Commission articulated in U-
8 21859 and reaffirmed in U-21990.

9 DTE's no-cost-shift showing rests on two things: a with-and-without cost-of-
10 service study ("COSS") comparison, and a calculation that DTE characterizes as an
11 approximately \$1.7 billion Affordability Benefit to other customers. I conclude that
12 neither, on this record, is sufficient on its own to support a durable finding that no costs of
13 serving the Customer are shifted to other ratepayers.

14 The COSS comparison is methodologically reasonable and identifies a meaningful
15 potential class-level redistribution worth examining, but it assumes essentially no
16 incremental utility rate base is required to serve the load and therefore cannot, standing
17 alone, establish that no costs caused by the Customer are shifted to other ratepayers.

18 The \$1.7 billion Affordability Benefit estimate is built on DTE's own legitimate
19 modeling tools, but it carries meaningful uncertainty: it is a 20-year nominal sum, not a
20 present value; DTE's own exhibit shows four years (2035–2038) in which other customers
21 bear modeled net cost rather than net benefit; the cost side is anchored on a hypothetical
22 727 MW gas-with-carbon-capture proxy plant assumed in service in 2033 that DTE
23 concedes is a placeholder the 2026 IRP may or may not adopt; the carbon-capture cost line

1 embeds a federal 45Q tax-credit assumption that carries policy and eligibility risk; and the
2 underlying EnCompass and SERVVM modeling carries open assumption questions, with
3 part of it not fully reproducible on the record.

4 Taken together, these features mean the Commission should not treat the
5 Affordability Benefit as a complete answer to the no-cost-shift and public-interest
6 questions. Instead, any approval should be conditioned on systematic back-end
7 verification, true-up procedures, and an enforceable affordability backstop that ensure the
8 projected benefits are actually realized and that no costs are shifted to other ratepayers over
9 the 20-year life of the contracts.

10 **Q: What do you recommend the Commission do?**

11 A: I recommend that the Commission condition any approval of the Special Contracts on
12 reporting, verification, and true-up procedures that make the affordability backstop
13 operational and enforceable over the full 20-year term, containing at minimum: (1)
14 measurable triggers tied to the specific assumptions underlying Exhibit A-19—load factor,
15 resource adequacy and resource selections, the PSCR delta, the proxy plant or its
16 replacement, 45Q credit realization, and the storage program—as well as to the resource-
17 procurement conditions the Commission imposes; (2) a defined remedy if those triggers
18 are breached, including a true-up or claw-back to the Customer rather than to other
19 ratepayers; (3) a sunset/reopener mechanism tied to the IRP cadence; and (4) reporting
20 obligations—in this docket, the next general rate case, and the next IRP—sufficient for the
21 Commission and parties to verify performance over the life of the contract.

22 The verification must be systematic, not a one-time front-end review. It should be
23 recurring on a defined cadence—most naturally the IRP cadence—with required interim

1 reporting, and it must rest on a properly maintained “without-customer” counterfactual
2 baseline so that the ex post but-for analysis can isolate the costs actually caused by the
3 Customer’s load from other system changes. The actual but-for analysis should be
4 performed in DTE’s general rate cases and its next IRP and must include running the IRP
5 with and without the Customer load using DTE’s actual resource modeling rather than the
6 placeholder construct in this record.

7 Finally, the backstop should require DTE to demonstrate that it evaluated and,
8 where cost-effective, pursued the opportunities MEI/CEO witness Sherman identifies—
9 Virtual Power Plants, third-party owned resources, and the resource-ownership structure—
10 before any claimed benefit can be recognized as supporting a finding that the contracts are
11 in the public interest.

12 **Q: Does this conclude your testimony?**

13 **A:** Yes.

1 MS. DUCKWORTH: Thank you. At this time,
2 on behalf of MEICEO, I move to bind into the record the
3 Direct Testimony of Chelsea Hotaling, noting that there
4 are Public and Confidential versions, consisting of a
5 cover page, a table of contents, and 26 pages of
6 questions and answers. I also move for the admission of
7 Ms. Hotaling's testimony Exhibits MEICEO-3 through
8 MEICEO-17.

9 JUDGE STALEY: All right. Are there any
10 objections to the binding in of the prefiled Direct
11 Testimony of Chelsea Hotaling, which has a Confidential
12 and Public version, as well as the admission of Exhibits
13 MEICEO-3 through MEICEO-17?

14 Hearing none, the prefiled Direct
15 Testimony of Chelsea Hotaling, with a Confidential and
16 Public version, are bound into the record, and Exhibits
17 MEICEO-3 through MEICEO-17 are admitted into evidence.

18 (Public Direct Testimony bound in.)

19 - - -

20 (Confidential Direct Testimony found on Page 960 of
21 the Confidential Record.)

22 - - -

**STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION**

In the matter of the application of DTE	)	
ELECTRIC COMPANY for approval of	)	Case No. U-22058
special contracts and for other relief.	)	

PUBLIC DIRECT TESTIMONY OF

CHELSEA HOTALING

ON BEHALF OF

**THE MICHIGAN ENERGY INNOVATION BUSINESS COUNCIL, INSTITUTE FOR
ENERGY INNOVATION, ECOLOGY CENTER, ENVIRONMENTAL LAW & POLICY
CENTER, UNION OF CONCERNED SCIENTISTS, AND VOTE SOLAR**

June 5, 2026

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1 **I. INTRODUCTION AND QUALIFICATIONS**

2 **Q. Please state your name and business address.**

3 A. My name is Chelsea Hotaling. I am a Senior Consultant at Energy Futures Group (“EFG”).
4 My business address is 10298 Route 116 Hinesburg, Vermont 05461.

5 **Q. On whose behalf are you appearing in this case?**

6 A. I am testifying on behalf of the Ecology Center, Environmental Law and Policy Center,
7 Union of Concerned Scientists, and Vote Solar, collectively referred to as the “Clean
8 Energy Organizations” or “CEO,” as well as the Michigan Energy Innovation Business
9 Council (“EIBC”) and Institute for Energy Innovation (“IEI”). I will refer to these
10 organizations collectively as “MEI/CEO”.

11 **Q. Please describe Energy Futures Group.**

12 A. EFG is a clean-energy consulting firm headquartered in Hinesburg, Vermont, with offices
13 in New York, North Carolina, and Oregon. EFG has two primary areas of practice. The
14 first is in the design, implementation, and evaluation of programs and policies to promote
15 investments in efficiency, renewable energy, other distributed resources, and strategic
16 electrification. The second is in integrated resource planning and related analyses. EFG
17 staff have delivered projects on behalf of energy regulators, government agencies, utilities,
18 and advocacy organizations in at least forty states, eight Canadian provinces, and several
19 countries in Europe.

20 **Q. Please summarize your professional experience and educational background.**

21 A. I have worked for ten years in electric utility regulation and related fields. I have reviewed
22 dozens of integrated resource plans and other filings by utilities in Arizona, Colorado,
23 Georgia, Kansas, Kentucky, Iowa, Indiana, Michigan, Missouri, Montana, Minnesota, New

1 Mexico, Nova Scotia, Puerto Rico, South Carolina, West Virginia, and Wisconsin. I have
2 performed my own capacity expansion, production cost, and reliability modeling in
3 numerous cases using multiple models, including EnCompass, Aurora, PLEXOS, and the
4 Strategic Energy & Risk Valuation Model (“SERVM”).

5 I received a Bachelor’s Degree in Accounting and Economics from Elmira College
6 in 2011. I also received a Master of Business Administration Degree in 2012, a Master’s
7 Degree in Environmental Policy in 2019, and a Master’s Degree in Data Analytics in 2020,
8 all from Clarkson University. My resume is attached as Exhibit MEICEO-3.

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

10 A. Yes. I provided testimony in the following cases:

- 11 • *In the Matter of the Application of DTE for Approval of its Integrated Resource*
12 *Plan*, Case No. U-21193.
- 13 • *In the Matter of the Application of Indiana Michigan Power Company for*
14 *Approval of its Integrated Resource Plan*, Case No. U-21189.
- 15 • *In the Matter of the Application of Consumers Energy Company for Approval*
16 *of its Integrated Resource Plan*, Case No. U-21090.

17 I have also filed testimony before the Public Service Commission of West Virginia,
18 the Public Service Commission of South Carolina, the Montana Public Service
19 Commission, the Public Service Commission of Wisconsin, the Georgia Public Service
20 Commission, the Kentucky Public Service Commission, the Iowa Utilities Board, and the
21 Colorado Public Utilities Commission.

22 **Q. Are you sponsoring any exhibits?**

23 A. Yes, I am sponsoring the following exhibits:

- 24 • Exhibit MEICEO-3: Resume of Chelsea Hotaling
- 25 • Exhibit MEICEO-4: DTE response to CEOMEIBCIEIDE 1.8bi

- 1 ● Exhibit MEICEO-5: DTE response to AGDE 1.18
- 2 ● Exhibit MEICEO-6: DTE response to CEOMEIBCIEIDE 1.5a
- 3 ● Exhibit MEICEO-7: DTE response to CEOMEIBCIEIDE 1.16c
- 4 ● Exhibit MEICEO-8: DTE response to CEOMEIBCIEIDE 1.26
- 5 ● Exhibit MEICEO-9: DTE response to CEOMEIBCIEIDE 1.13
- 6 ● Exhibit MEICEO-10: DTE response to CEOMEIBCIEIDE 1.27a
- 7 ● Exhibit MEICEO-11: DTE responses to MNSDE 1.15a and to CEOMEIBCIEIDE
- 8 2.2ai
- 9 ● Exhibit MEICEO-12: DTE response to CEOMEIBCIEIDE 2.3a and 2.3b
- 10 ● Exhibit MEICEO-13: DTE response to CEOMEIBCIEIDE 1.20b
- 11 ● Exhibit MEICEO-14: DTE response to MNSDE 2.5b
- 12 ● Exhibit MEICEO-15: DTE response to CEOMEIBCIEIDE 1.14b
- 13 ● Exhibit MEICEO-16: DTE response to CEOMEIBCIEIDE 1.3c
- 14 ● Exhibit MEICEO-17: DTE response to MNSDE 1.2b

15 **Q. What is the purpose of your testimony?**

16 A. The purpose of my direct testimony is to evaluate and respond to the resource adequacy
17 analysis of Google’s (“Customer”) load and proposed resources. This includes the impact
18 on DTE’s (“the Company”) Planning Reserve Margin Requirement (“PRMR”), and the
19 resource adequacy modeling performed by the Company in SERVVM. I present modeling I
20 performed in SERVVM as part of this evaluation. In addition, I also discuss the potential
21 risk from changes in accredited capacity for resources under MISO’s seasonal construct
22 and identify some of the cost and benefit categories that might change with updated
23 capacity expansion modeling in the upcoming Integrated Resource Plan (“IRP”).

1 **Q. Please summarize your conclusions and recommendations.**

2 A. It is unclear how DTE will assign costs for any incremental resources needed to serve the
3 Customer outside of the resources included in the Clean Capacity Accelerator Agreement
4 (“CCAA”). In order to address the concerns raised in my testimony, the Commission
5 should require the Company to file an annual report in this docket to report on the
6 Customer’s load, accreditation of resources under the CCAA, and additional resources that
7 will be pursued in 2033 when the Customer’s Zonal Resource Credits (“ZRCs”) expire and
8 the Customer no longer engages in the demand response program. This report can also
9 serve to provide updates on the cost and benefits from the Customer so that this information
10 is contained in one docket instead of spreading the information over several dockets. As it
11 stands in the agreements presented by the Company in this proceeding, it is unclear what
12 obligation the Company has to present this information to the Commission and how or
13 when the Commission would know whether the Customer is paying its fair share of the
14 costs needed to serve its load.

15 Because additional capacity will be needed to serve the Customer, the Commission
16 could also pursue increasing the cap on renewables and energy storage under the CCAA.
17 Once responses to the Request for Proposals (“RFPs”) are received by the Company and
18 winning projects are determined, the Company can update its evaluation of the resource
19 adequacy of the system with the Customer’s load and resources from the RFP. The purpose
20 of this would be to not only evaluate the economics of the bids received, but to also see
21 what the makeup of the renewable resources is between solar and wind resources and what
22 influence the composition of the portfolio has on the Company’s resource adequacy
23 position. This will help to refine the resource adequacy analysis presented by the Company.

1 **II. CUSTOMER LOAD AND PROPOSED RESOURCES**

2 **Q. Please explain what the planned Customer load is and the resources included in the**
 3 **CCAA.**

4 A. The maximum load for the Customer is 1,000 MW, with materialization set to begin in
 5 December 2027 ramping to the maximum load by December 2028.¹ The resources under
 6 the CCAA include:

- 7 • Up to 480 MW of energy storage;²
- 8 • 1,600 MW of renewable resources; and
- 9 • 300 MW of Midcontinent Independent System Operator (“MISO”) Local
 10 Resource Zone (“LRZ”) 7 ZRCs.

11 Importantly, the 300 MW of ZRCs are only available from June 1, 2028, until May
 12 31, 2033.³ Beyond May 31, 2033, the Customer is not obligated to transfer ZRCs to the
 13 Company and the Company will not have access to them.⁴ DTE reported that the duration
 14 of the ZRCs was a “negotiated term agreed to by the Customer and the Company.”⁵

15 **Q. Is the Customer proposing additional resources that are not included in the CCAA?**

16 A. Yes. In addition to the energy storage, renewables, and ZRCs under the CCAA, the
 17 Customer is committing to 250 MW of demand response between June 2027 and May
 18 2033.⁶ DTE reports that the Customer’s demand response will be covered under the Rider
 19 12 Demand Response Agreement.

¹ Direct Testimony of Neal Foley on behalf of DTE Electric Company (“Foley Direct”), Case No. U-22058, at 9.

² *Id.* at 25. This can be up to 425 MW of four-hour lithium-ion energy storage and up to 55 MW of long duration storage.

³ *Id.* at 31.

⁴ Exhibit MEICEO-4.

⁵ Exhibit MEICEO-5.

⁶ Foley Direct at 6.

Q. Based on the Customer’s load and the resources included in the CCAA, what is the projected capacity position for this Customer in 2033 after the expiration of the ZRCs and the demand response?

A. Table 1 shows the 2033 capacity position for the Customer in the summer, fall, and winter season. The focus is on these seasons since the ZRCs and demand response expire by June 1, 2033. The PRMR column reflects the customer’s peak, with the Company’s projected coincidence factor, and then the MISO seasonal Planning Reserve Margin (“PRM”) is applied to the Customer’s coincident peak. The “Accredited Resources” column reflects the firm capacity of the renewable and energy storage resources. The Customer’s capacity position is based on the difference between the accredited resources and the PRMR. As can be seen in **Table 1**, the resources proposed under the CCAA are not projected to provide enough firm capacity to cover the PRMR after the ZRCs and demand response expire.

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Table 1. Customer’s 2033 Capacity Position (MW)⁷

Season	PRMR	Accredited Resources	Capacity Position
Summer	■	■	■
Fall	■	■	■
Winter	■	■	■

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Q. Does the Customer’s projected capacity position in 2033 raise concerns for resource adequacy?

A. Yes, the expiration of the ZRCs and the end of the Customer’s voluntary participation in the demand response program create a deficit that will need to be met with additional

⁷ Calculated based on the EnCompass output reports provided in “NDA U-22058 CEOMEIBCIEIDE-1.12 DC2 Output Reports CONFIDENTIAL” (Exhibit MEICEO-20).

resources in order to ensure compliance with the MISO seasonal construct. It also raises questions about the resource adequacy impact of the Customer's load on the Company's system. Resource adequacy modeling in SERVVM is discussed in more detail in the next section.

III. SERVVM

Q. What is SERVVM?

A. SERVVM is a widely used reliability planning and production cost model. SERVVM evaluates an electric system through the lens of uncertainty and risk by taking information about past risks, such as historical weather, economic forecast error, load uncertainty, unit performance, to evaluate the likelihood and magnitude of reliability events on a system. SERVVM uses historical weather patterns to develop load profiles for each weather year to predict how loads would respond if the weather experienced in that particular year were to repeat. SERVVM then applies load forecast error multipliers with their associated probabilities to capture the potential for uncertainty in economic forecasts.⁸ The weather years included in the model also reflect the uncertainty around renewable resources, as the profiles for each resource capture the expected availability for that resource based on the historical weather profiles. SERVVM models the uncertainty around generator unit availability through the simulation of random unit outage draws.⁹

Q. How can SERVVM be used to inform utility resource planning?

A. SERVVM can be used in several different ways. For instance, SERVVM can be used to inform

⁸ Since economic variables are typically one of the key variable inputs in the development of a load forecast, the load forecast error multipliers simulate the expected probability that the peak demand would be higher or lower than the forecast.

⁹ Generators with forced outage units will have a distribution of outage inputs associated with them. SERVVM will then pull from those inputs to model the outages.

1 resource adequacy studies and determine the reserve margin necessary for a utility system
2 to satisfy reliability metrics.¹⁰ It can also be used to calculate Effective Load Carrying
3 Capacity (“ELCC”) of solar, wind, and battery storage resources. SERVVM can also be used
4 to evaluate specific candidate resource portfolios to determine whether they satisfy
5 reliability criteria. The simulations performed in SERVVM result in the production of several
6 reliability metrics, including the Loss of Load Expectation (“LOLE”), which is a metric
7 used to evaluate the reliability of a resource portfolio. LOLE is the expected number of
8 days in a year where there will not be enough resources to serve load. Most typically,
9 utilities use a 1 day in 10-year LOLE reliability standard (0.1 days/year).

10 **Q. How is SERVVM different from capacity expansion modeling?**

11 A. Capacity expansion optimizes to identify the least cost portfolio that meets a utility’s
12 PRMR. SERVVM evaluates whether the portfolio of resources from the capacity expansion
13 modeling performed in EnCompass meets the 0.1 LOLE threshold. As discussed in witness
14 Brooks’s testimony, the main difference between EnCompass and SERVVM is that capacity
15 expansion models reflect normal weather conditions and average generator performance in
16 a deterministic analysis whereas SERVVM is a probabilistic analysis that incorporates risks
17 from extreme weather, economic load forecast uncertainty, and generator performance
18 uncertainty.¹¹

19 **Q. How did DTE use SERVVM for this proceeding?**

20 A. DTE evaluated the proposed Customer load and resources for the 2029 and 2033 study
21 years in SERVVM to see if the 0.1 LOLE resource adequacy standard was met. DTE reported

¹⁰ MISO utilizes SERVVM to determine the seasonal planning reserve margins (“PRMs”).

¹¹ Direct Testimony of Justin J.W. Brooks on behalf of DTE Electric Company (“Brooks Direct”), Case No. U-22058, at 7.

that 2033 was selected for evaluation to ensure that the resource portfolio meets the LOLE threshold after the expiration of the ZRCs and demand response.¹²

Q. What resources did DTE model for the CCAA and Customer demand response?

A. Energy storage was modeled at 400 MW of four-hour duration and 50 MW of eight-hour duration.¹³ The renewable resources were modeled as 1,600 MW of solar.¹⁴ The Customer demand response and ZRC resources expired by June 1, 2033.¹⁵

Q. What did DTE find in the SERV modeling conducted?

A. **Table 2** provides the LOLE results for the resource portfolio with the Customer load and resources included for 2029 and 2033. The 2029 study year meets the LOLE threshold, but in 2033, the 0.238 LOLE exceeds the 0.1 LOLE threshold. Since 2033 did not meet the 0.1 LOLE threshold, “perfect capacity”¹⁶ in the amount of 677 MW was added to bring the DTE system to the 0.1 LOLE.¹⁷

Table 2. DTE SERV Results¹⁸

Study Year	LOLE
2029	0.102
2033	0.238
2033	0.093

Q. Did you conduct any alternative modeling in SERV?

A. Yes, I did. I started with the SERV database¹⁹ provided by DTE and made several modifications, which I will discuss in more detail below.

¹² Direct Testimony of Shawn Burgdorf on behalf of DTE Electric Company (“Burgdorf Direct”), Case No. U-22058, at 10.

¹³ Exhibit MEICEO-6.

¹⁴ Exhibit MEICEO-7.

¹⁵ Brooks Direct at 9.

¹⁶ This is modeled as a resource with no outages.

¹⁷ Brooks Direct at 9.

¹⁸ *Id.* at 8, 9, and 11.

¹⁹ Exhibit MEICEO-8.

1 **Q. What modification did you make to how DTE modeled the data center load and**
2 **resources for Oracle and Google?**

3 A. I broke out the load and resources for Oracle²⁰ and Google to better understand how the
4 load and resources for those customers drove the LOLE results from the base case
5 assumption without any data center load. DTE reported that additional renewable resources
6 were modeled to ensure compliance with the renewable requirements tied to the Oracle
7 load in the amount of 662 MW of solar in 2030, 332 MW of solar in 2031, and 809 MW
8 of solar in 2032.²¹ Cases without the Oracle and Google customers removed both the load
9 and resources associated with each customer.

10 **Q. Did you make any modifications to how DTE modeled Monroe Units 1 and 2?**

11 A. DTE modeled the Monroe 1 and 2 Units retiring December 2032.²² However, proxy
12 thermal resources were modeled at the same size as Monroe Units 1 and 2 for the 2033
13 study year. DTE reports that the future generation resources to replace Monroe Units 1 and
14 2 will be determined in the Company's next IRP.²³ In order to separate out what factors are
15 driving the resource adequacy results, I ran SERVVM with the proxy resources for Monroe
16 Units 1 and 2 and without those proxy resources included to see the resulting impact on the
17 LOLE. The purpose of removing the proxy resources was not to evaluate the portfolios
18 against a 0.1 LOLE threshold, but to evaluate what the impact to the LOLE is when the
19 Oracle and Google load and resources were included without any replacement for the
20 Monroe Units.

²⁰ The Company's base case included the load, incremental renewable resources, and energy storage resources associated with the Oracle data center facility, which was approved by the Commission in U-21990. Burgdorf Direct Testimony at 17. The Oracle facility's maximum load is 1.4 GW and is expected to come online beginning in January 2027 with max load by December 2027.

²¹ Exhibit MEICEO-9.

²² Exhibit MEICEO-10

²³ Burgdorf Direct at 9; Exhibit MEICEO-11.

1 **Q. What are the results of the SERVVM modeling you performed?**

2 A. **Table 3** shows the LOLE results for each data center load case with the proxy resources
3 for Monroe 1 and 2 included. The results indicate that the LOLE threshold of 0.1 days per
4 year is not met under the Customer's projected load and resources in 2033.

5 **Table 3. SERVVM Results for 2033 with Monroe Proxy Resources**

Monroe 1 & 2	Data center Load	LOLE
Proxy resources included	No Oracle or Google	0.128
Proxy resources included	Add Oracle	0.121
Proxy resources included	Add Oracle and Google	0.236

6 **Table 4** shows the LOLE result for each data center load case without the proxy
7 Monroe resources. It is important to note that the three studies without a replacement proxy
8 resource for Monroe Units 1 and 2 are not intended to be evaluated against a 0.1 LOLE
9 threshold. These cases capture the impact of the Customer's projected load and resources
10 without any assumptions about what resource technologies might replace Monroe Units 1
11 and 2. These results indicate that even if no specific replacement is assumed for Monroe
12 Units 1 and 2, the Customer's projected load and resources create a resource adequacy need
13 in 2033.

14 **Table 4. SERVVM Results for 2033 without Monroe Proxy Resources**

Monroe 1 & 2	Data center Load	LOLE
No proxy resources	No Oracle or Google	0.560
No proxy resources	Add Oracle	0.532
No proxy resources	Add Oracle and Google	0.941

15 **Q. Is there anything you want to note about the SERVVM model configured by DTE?**

16 A. The SERVVM topology reflects DTE's interaction with the rest of MISO, which includes
17 the non-DTE portion of Zone 7, and then Zones 1-6.²⁴ In order to configure these zones in

²⁴ Brooks Direct at 8.

1 SERVM, assumptions have to be made about the load and resources for the 2029 and 2033
2 study years modeled in SERV. The assumptions around the load and resources for the
3 MISO zones in DTE’s model are important because these assumptions have implications
4 for the level of resource adequacy for each of these zones.

5 For example, the degree to which its projections for the MISO zones reflect large
6 load growth and future resources for those large loads is not certain. DTE reported that
7 load assumptions are based on a 2023 MISO workshop and resource assumptions are from
8 the MISO 2024 Regional Resource Assessment (“RRA”).²⁵ I raise this because it is not
9 clear the degree to which the resource adequacy of the MISO zones influence the LOLE
10 results for DTE. If some of the MISO zones have a more optimistic LOLE, this might
11 overstate the benefit of interactions with other zones. In DTE’s model, this could result in
12 a lower LOLE if transfers from the other regions might be helping DTE avoid periods of
13 unserved energy because DTE can rely on imports from those zones in SERV.

14 **Q. The SERV modeling presented by DTE identified a need for 637 MW of perfect**
15 **capacity in 2033. How was the perfect capacity modeled by DTE?**

16 A. DTE modeled the perfect capacity as a proxy combined cycle gas turbine with carbon
17 capture and sequestration (“CCGT with CCS”). However, DTE reports that the type of
18 resources needed will be determined in the next IRP.²⁶

19 **Q. Has DTE acknowledged that the Customer’s load and removal of the ZRCs and**
20 **demand response by June 1, 2033, is driving the need for the perfect capacity resource**
21 **to address resource adequacy?**

²⁵ Exhibit MEICEO-12.

²⁶ Burgdorf Direct at 10.

1 A. DTE's responses to discovery questions on the perfect capacity resource do not appear to
2 be aligned with what was said in testimony. In direct testimony witness Burgdorf stated,
3 "Additionally, once the ZRC contract and the contracted demand response end on May 31,
4 2033, a proxy dispatchable resource is modeled to support resource adequacy."²⁷ However,
5 when asked in discovery to confirm if the proxy CCGT with CCS was added because of
6 the expiration of the ZRCs and demand response resources, DTE responded:

7 *Not confirmed. The proxy CCGT with CCS was added to meet the total*
8 *system reliability requirement needs in 2033 in the context of analyzing*
9 *resource adequacy requirements solely for purposes of performing the*
10 *customer benefit analysis in this special contract matter. While the*
11 *expiration of the ZRC contract and demand response are factored into the*
12 *2033 analysis, they do not define the 2033 system reliability requirements.*²⁸
13

14 In response to a similar question from MNS that asked if the proxy CCGT was only
15 modeled to support the addition of the Customer's load, DTE said:

16 *Not confirmed. Refer to CEOMEIBCIEIDE-1.22. The Company does not*
17 *designate specific individual resources as being used exclusively to serve*
18 *the Customer's load or any individual customer's load. Instead, in its*
19 *Integrated Resource Plan (IRP) modeling, the Company will evaluate the*
20 *incremental impact of the Customer's load on system resource needs by*
21 *comparing portfolios with and without that load and identifying the*
22 *additional capacity or energy resources required to reliably serve total*
23 *system demand.*²⁹
24

25 Because the record is not clear on this point, the Company should provide clarity on rebuttal
26 as to whether the Customer's load and removal of ZRCs and demand response in 2033 is
27 driving the resource adequacy need and the proxy CCGT with CCS included in the
28 Company's modeling results.
29

²⁷ *Id.* at 11.

²⁸ Exhibit MEICEO-13.

²⁹ Exhibit MEICEO-14.

1 **Q. Is the Customer's load and removal of the ZRCs and demand response impacting the**
2 **LOLE results for the 2033 study year?**

3 A. Yes. DTE's SERVVM modeling and the additional SERVVM modeling I include in my
4 testimony indicate that the DTE system will not be resource adequate in 2033 after the
5 expiration of the ZRCs and demand response without additional resources.

6 **Q. Is it your understanding that DTE will determine any incremental resource needs**
7 **resulting from the Customer in the next IRP filing?**

8 A. Yes, based on the Company's testimony and responses to discovery questions, DTE will
9 identify the specific resources to meet any incremental need from the Customer in the IRP.

10 **Q. Do you have a suggested modeling run that DTE should evaluate in the IRP?**

11 A. Yes. If the Customer provides information that either the ZRCs or engagement in demand
12 response can extend beyond the planned expiration date, that should be considered in a
13 modeling run to evaluate whether any incremental resources are needed above the ZRCs
14 and demand response. Although all resource alternatives should be considered, it does not
15 seem like there will be an opportunity to revisit the potential for an extension of the ZRCs
16 and demand response if resource decisions are not made until the IRP and would be made
17 there based on the modeling that does not include those resources.

18 In addition, the timing of the expiration of the ZRCs and demand response is within
19 six months of the Monroe 1 and 2 retirement. It is unclear what impact the expiration of
20 the ZRCs and demand response might have on the replacement resources needed for
21 Monroe given the timing of the need for resources for both the Customer and for Monroe
22 1 and 2.

1 **Q. Do you have any other recommendations related to the impact of Customer's load**
2 **and removal of the ZRCs and demand response on projected resource adequacy in**
3 **2033?**

4 **A:** Yes. In light of my analysis above, the Commission should require as a condition of
5 approval that the Company's agreements allow for an extension of the Customer's
6 obligations to provide the ZRCs and/or engage in demand response beyond 2033. The
7 availability of an extension could be conditioned upon whether the extension of these
8 resources could address incremental need identified as a result of the Customer in the next
9 IRP.

10 **Q: Do you have any additional concerns about any incremental resources that will be**
11 **identified in the next IRP?**

12 **A.** I do and I will discuss those concerns in more detail in the remaining sections of my
13 testimony.

14 **IV. AFFORDABILITY BACKSTOP**

15 **Q. In the previous section of your testimony you indicated that you have a concern about**
16 **the incremental resources that will be identified in the next IRP. Can you explain**
17 **what your concern is?**

18 **A.** I am concerned about the difference in how the resources under the CCAA are cost
19 allocated compared to the future resources that will be needed to meet resource adequacy
20 in 2033. The Company's testimony explains that the CCAA resource costs will be paid by
21 the Customer. For example, witness Foley said in his testimony:

22 *"The CCAA, Exhibit A-18, governs the obligations of the Company and the*
23 *Customer related to the deployment and cost recovery of up to 480 MW of*
24 *energy storage projects and up to 1,600 MW of renewable energy projects.*

1 *The Customer will pay the full cost (i.e., revenue requirement) of the*
 2 *projects over each project's depreciable life.”³⁰*

3
 4 *“For both energy storage and renewable energy projects, the Customer will*
 5 *pay the full cost of each project during its respective depreciable life.”³¹*

6
 7 *“Under this approach, the Customer pays the actual costs of each project*
 8 *deployed under the CCAA.”³²*

9
 10 *“The CCAA pricing and associated reconciliation processes ensure that the*
 11 *Customer fully pays for the actual costs of the energy storage and*
 12 *renewable energy projects. In this way, the CCAA prevents cross-*
 13 *subsidization of the projects and mitigates the risk of stranded assets.”³³*

14
 15 **Q: Is the same true for any incremental resources that may be identified in the next IRP**
 16 **as necessary and resulting from the Customer's load?**

17 **A:** No. It is my understanding that any incremental resources identified in the next IRP would
 18 not be paid for by the Customer pursuant to the CCAA.

19 **Q:** **Will the conditions or terms of the Primary Service Agreement (“PSA”) address your**
 20 **concern around the treatment of future resources?**

21 **A:** It is not clear. The Company refers to the affordability backstop, or Section 5.1.3 of the
 22 PSA, for assurance that the Customer will pay all costs associated with its service. Section
 23 5.1.3 of the PSA says:

24 *The Parties acknowledge that a goal of this Agreement and the Related*
 25 *Agreements is to protect other customers, other customer classes and Company*
 26 *from funding the costs to serve Customer. The Parties also acknowledge that*
 27 *the combined revenues received by the Company under this Agreement and the*
 28 *applicable Related Agreements along with any avoided costs attributable to*
 29 *Google should be considered in regulatory proceedings applicable to*
 30 *Company's cost to serve Customer, and the Parties shall act in good faith to*
 31 *ensure such combined revenues and avoided costs are presented in such*
 32 *proceedings to the extent applicable. If, at any time during the Term, the*
 33 *Commission (a) issues a ruling or order determining that the costs to serve*
 34 *Customer exceed the combined revenues paid or payable to the Company*

³⁰ Foley Direct at 23.

³¹ *Id.* at 27.

³² *Id.* at 30.

³³ *Id.* at 31.

*under this Agreement and the applicable Related Agreements, or (b) disallows Company's recovery of costs to the extent attributable to serving Customer, then, in either case, Customer agrees to comply with any such ruling or order to ensure that Customer pays all costs associated with its service from Company, and, as applicable, Customer shall reimburse Company for any unrecovered costs...*³⁴

MEI/CEO witness Kenworthy addresses the deficiencies in the Company's proposed affordability-backstop framework in more detail. However, I highlight here that based on this language in the PSA, the Company's specific obligations to present information on revenues and costs to serve the Customer to the Commission are not clear. In order for the Commission to determine whether the Customer is paying its fair share of the costs – including, for example, the costs associated with incremental resources that will be identified in the next IRP – it needs sufficient metrics, modeling, and reporting to inform such a determination. Further complicating matters, the costs and benefits for the Customer will be spread amongst several regulatory proceedings, as DTE witness Foley acknowledges.³⁵ Witness Foley identified the different proceedings where the Customer's benefits and costs will be considered as outlined in **Table 5**.

Table 5. Outline of Regulatory Proceedings³⁶

Customer Cost/Benefit	Proceeding Where Addressed
Any benefit to base rates	Rate cases
Incremental transmission investments	Power Supply Cost Recovery ("PSCR") plan and reconciliation cases
Long term generation needs	Integrated Resource Plan
Approval of renewable generation plans	Renewable Energy Plan ("REP")

³⁴ Exhibit A-16 at 8 (emphasis added).

³⁵ Foley Direct at 21.

³⁶ *Id.*

1 **Q. What recommendation do you have?**

2 A. The Company should be required to file an annual report in this docket to provide updates
3 on the Customer's load materialization and the accreditation for resources under the
4 CCAA,³⁷ in addition to the resources that will be pursued in 2033 when the Customer's
5 ZRCs expire and the Customer no longer engages in the demand response program. This
6 report should also include all information relating to the cost and benefits from the
7 Customer (even if otherwise presented or contained in other dockets) so that this
8 information is contained in one docket. A consolidated reporting requirement in this docket
9 will help ensure that all costs and benefits are considered and appropriately allocated to the
10 Customer.

11 **V. ACCREDITATION RISK**

12 **Q. Is there a chance that even more resources would be needed to reliably serve the**
13 **Google load?**

14 A. While the future accreditation for resources is not known at this time, the seasonal
15 accreditation assumptions in DTE's modeling for energy storage are likely too high for the
16 summer season based on the recent indicative estimates published by MISO. MISO has
17 released indicative resource accreditation values in anticipation of the shift to the Direct
18 Loss of Load ("DLOL") methodology for planning year ("PY") 2028 – 2029. **Table 6**
19 shows a comparison of MISO's published seasonal accreditation for solar, energy storage,
20 and wind.

³⁷ I discuss accreditation risks associated with the CCAA resources below.

Table 6. MISO Accreditation Changes (%)

	Summer	Fall	Winter	Spring
Solar:				
Prior to PY 2023-2024 ³⁸	45%	25%	6%	15%
PY 2023-2024	36%	31%	2%	18%
PY 2025-2026 ³⁹	45%	28%	19%	28%
Storage:				
Prior to PY 2023-2024	95%	95%	95%	95%
PY 2023-2024	94%	93%	91%	95%
PY 2025-2026	61%	88%	85%	90%
Wind:				
Prior to PY 2023-2024	18%	23%	40%	23%
PY 2023-2024	11%	15%	16%	16%
PY 2025-2026	8%	15%	23%	15%

DTE’s energy storage accreditation assumption, in particular for the summer season, may introduce risk that the energy storage in the CCAA is not sufficient. DTE’s summer storage accreditation assumption is more in line with the “PY 2023-2024” row in **Table 6**. This assumption is higher than with the accreditation values more recently released by MISO and reported as “PY 2025-2026” in the table. I will note that DTE may already be capturing some risk in its more conservative accreditation assumptions for solar resources, but if any portion of the 1,600 MW of renewables are wind resources, that accreditation assumption will capture the lower summer value projected for wind. Therefore, I do not think DTE’s more conservative accreditation assumptions for solar resource alleviate the risks related to CCAA energy storage resources that I identify here.

³⁸ Burgdorf Direct at 8 n.3. *See also* MISO RASC “Market Redefinition: Accreditation Reform”. Retrieved from <https://cdn.misoenergy.org/20240228%20RASC%20Item%2005a%20Accreditation%20Presentation%20RASC-2020-4%202019-2631885.pdf>

³⁹ Exhibit MEICEO-15.

1 **Q. Does the contract with the Customer account for accreditation risk for the CCAA**
2 **resources?**

3 A. No. Risk to changes in resource accreditation is accounted for as it relates to the Customer's
4 demand response program but not for the CCAA resources. Witness Burgdorf testified that
5 there are contract damages for non-performance, and that "[...] any future MISO PY lost
6 accreditation for non-performance will be assessed damages for the lost ACP revenues plus
7 at least the CONE.⁴⁰ This ensures full recovery of any lost revenues from the Planning
8 Resource Auction."⁴¹ Therefore, while there are contract damages related to the
9 accreditation of the Customer's demand response, the CCAA does not address how
10 accreditation risk would be handled for the energy storage and renewable resources.

11 As it stands, the Company can only deploy up to 480 MW of energy storage and
12 1,600 MW of renewable projects.⁴² Having a cap at that amount does not leave any
13 flexibility for consideration of how the accreditation of those resources might evolve over
14 time. If the accreditation for the CCAA resources ends up being lower than what DTE has
15 projected, it is likely that DTE will need to procure additional capacity above what was
16 shown in **Table 1**.

17 I am concerned that this accreditation risk for energy storage resources has not been
18 considered and may not be captured under any costs calculated under affordability
19 backstop provision at Section 5.1.3 of the PSA.

20 **Q. What recommendation do you have as it relates to the accreditation risk you**
21 **identified?**

⁴⁰ Cost of New Entry ("CONE").

⁴¹ Burgdorf Direct at 23.

⁴² Exhibit MEICEO-16.

1 A. The Commission should consider directing the Company to increase the cap on the energy
2 storage and renewable energy projects. If the cap is relaxed, DTE could evaluate the RFP
3 responses and determine whether additional resources are economic under a range of
4 accreditation assumptions. In addition, as I discussed earlier in my testimony, part of the
5 annual reporting to the Commission in this docket should include an ongoing evaluation of
6 the Customer's load and accreditation of the resources in the CCAA and any incremental
7 resources identified for the Customer. Including this in the reporting will ensure ongoing
8 monitoring of the accreditation risk and cost assignment that might be needed if there is a
9 significant change in resource accreditation that would impact the Company's capacity
10 position and cause the Company to need to procure additional capacity.

11 **VI. COST BENEFIT ANALYSIS CALCULATION**

12 **Q. Did DTE present a benefit cost calculation for the Customer?**

13 A. Yes. The total benefit cost calculation is based on several categories of reported benefits
14 and costs. DTE reported an estimated \$1.7 billion of benefit to other customers based on
15 the calculation developed for this proceeding.⁴³ CEO/MEI Witness Kenworthy addresses
16 the cost benefit calculation in more detail in his testimony. My testimony addresses the
17 calculations related to the EnCompass modeling used to develop some of the reported costs
18 for the proxy CCGT and benefits related to the energy storage pull ahead and PSCR.⁴⁴

19 **Q. How was the EnCompass model used to inform DTE's cost benefit calculation?**

20 A. EnCompass was used to perform capacity expansion and production cost modeling for two
21 scenarios. The first scenario, or the "base case," did not include the Customer's load,

⁴³ Direct Testimony of Aaron Willis on behalf of DTE Electric Company ("Willis Direct"), Case No. U-22058, at 9. Willis at 4.

⁴⁴ *Id.* at 7.

1 CCAA resources or the demand response program. The second scenario, or the “Customer
2 Data Center Case” included the Customer’s load, CCAA resources, the Customer’s
3 demand response program, and the level of perfect capacity identified by witness Brooks
4 as needed for resource adequacy in 2033. That perfect capacity was modeled as a CCGT
5 with CCS in EnCompass. Both scenarios assumed proxy thermal units for Monroe 1 and
6 2. DTE then used the results of the scenarios for certain categories of the cost benefit
7 calculation, including MISO market purchases and sales, operational costs for generation,
8 and the energy storage pull ahead benefit.

9 **Q. Are some of the cost and benefit categories likely to change with updated modeling in**
10 **the IRP?**

11 A. Yes, the reported costs and benefits related to the proxy CCGT, the impact of MISO market
12 purchases and sales, and the storage pull ahead are likely to change with updated modeling
13 in the upcoming IRP. This is the result of several factors which include:

14 (1) The IRP will model a longer time horizon compared to what was contemplated
15 for this proceeding as EnCompass was optimized between 2028 and 2038;⁴⁵

16 (2) DTE has reported that the resource technologies needed in place of the proxy
17 CCGT will be determined in the upcoming IRP;

18 (3) The proxy CCGT resource likely influenced the MISO market purchases and
19 sales in the EnCompass model; and

20 (4) **BEGIN CONFIDENTIAL** [REDACTED]
21 [REDACTED]

⁴⁵ Burgdorf Direct at 17 (Table 2).

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Q. Can you explain what impact the modeling time horizon might have on capacity expansion modeling and the resulting cost benefit calculation?

4

5

A. DTE's capacity expansion modeling time period is 2028 to 2038 for this proceeding. The modeling time period for the IRP will extend beyond 2038. What this means is that the capacity expansion plan might be different when a longer time horizon is considered. This may have implications for the reported benefits calculated for the storage pull ahead in DTE's analysis.

6

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Q. Can you explain what the impact might be from modeling different resource technologies from the proxy CCGT with CCS?

11

12

A. The modeling performed by DTE assumed a CCGT with CCS for the purposes of the cost benefit calculation. The selection of alternative resource technologies in place of the CCGT with CCS would impact the resulting revenue requirement for the replacement resources. In addition, it will likely impact the result of any reported MISO market benefits. In DTE's modeling, the average capacity factor of the CCGT with CCS is approximately **BEGIN** **CONFIDENTIAL** **END CONFIDENTIAL**.⁴⁷ If inclusion of the CCGT with CCS resulted in increased MISO market sales and reduced market purchases, and the resource replacement does not have a similar generation profile, it is possible that any reported market revenues would be overstated and market purchases would be understated.

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⁴⁶ Based on a review of the EnCompass modeling inputs provided in "NDA U-22058 CEOMEIBCIEIDE-1.12 Base CE Inputs CONFIDENTIAL."

⁴⁷ Capacity factor calculated from the EnCompass output provided as "NDA U-22058 CEOMEIBCIEIDE-1.12 DC2 Output Reports CONFIDENTIAL".

Q. Can you explain what impact DTE’s ITC assumption for energy storage had on the model results?

A. One of the benefits that DTE included in its calculation is what DTE refers to as “the storage pull ahead.” DTE reported that when the Customer’s load and CCAA resources are included, 500 MW of energy storage can be avoided in 2035 and 2036 due to serving the Customer’s load under the PSA and CCAA.⁴⁸ When reviewing the output for the base case without the Customer load and the case with the Customer load, the Company will be well over the summer PRM, and the base case without the Customer has an even higher reserve margin when compared to the Customer case as shown in **Table 7**. It is likely that the Company’s assumption for when the ITC energy storage tax credit expires is driving the model to select the maximum amount of energy storage before the ITC expires.

BEGIN CONFIDENTIAL

Table 7. Summer Reserve Margin Comparison (%)⁴⁹

Year	Customer	Base	PRM
2036	■	■	■
2037	■	■	■
2038	■	■	■

END CONFIDENTIAL

It is likely that EnCompass is selecting additional energy storage above what is needed to meet the PRM due to that energy storage resulting in lower system costs. This is something that will be important to investigate in more detail for the modeling performed in the IRP to identify what costs are reduced by the energy storage resources. Similar to the other items in the cost benefit calculation, it is possible that these projected expansion

⁴⁸ Burgdorf Direct at 12 (Table 1); Exhibit MEICEO-17.

⁴⁹ Calculated from the EnCompass output provided as “NDA U-22058 CEOMEIBCIEIDE-1.12 DC2 Output Reports CONFIDENTIAL” and “NDA U-22058 CEOMEIBCIEIDE-1.12 Base Output Reports CONFIDENTIAL”.

1 plans might change with the IRP modeling and it is unclear whether the energy storage pull
2 ahead will remain a benefit in the Customer cost benefit calculation.

3 **Q. Are there other modeling changes that might influence the result for DTE's capacity**
4 **expansion for the base case without the Customer's load?**

5 A. Yes. Additional modeling inputs that might be updated and could impact the expansion
6 results include resource costs, resource build limits, resource accreditation, and commodity
7 price forecasts.

8 **VII. RECOMMENDATIONS**

9 **Q. Please summarize your recommendations to the Commission.**

10 A. Based on my findings, it is likely that the Company will require additional resources to
11 serve the Customer and maintain resource adequacy in 2033 when the Customer's ZRCs
12 and demand response obligations expire. For that reason, I recommend that the
13 Commission direct DTE to pursue an agreement with the Customer that would allow for
14 the extension of the ZRCs and/or demand response beyond 2033, if the extension of these
15 resources could address incremental need identified as a result of the Customer in the next
16 IRP.

17 Additionally, it is unclear how DTE will assign the costs for any incremental
18 resources needed to serve the Customer outside of the resources included in the CCAA. In
19 order to address the concerns raised in my testimony, the Commission should require the
20 Company to file an annual report in this docket to report on the Customer's load,
21 accreditation of resources under the CCAA, and additional resources that will be pursued
22 in 2033 when the Customer's ZRCs expire and the Customer no longer engages in the
23 demand response program. This report can also serve to provide updates on the cost and

1 benefits from the Customer so that this information is contained in one docket instead of
2 spreading the information over several dockets. As it stands in the agreements presented
3 by the Company in this proceeding, it is unclear what obligation the Company has to
4 present this information to the Commission nor how or when the Commission would know
5 whether the Customer is paying its fair share the costs needed to serve its load.

6 Because additional capacity will be needed to serve the Customer, and for the
7 accreditation risk I identified, the Commission could also pursue increasing the cap on
8 renewables and energy storage under the CCAA. Once responses to the RFPs are received
9 by the Company and winning projects are determined, the Company can update its
10 evaluation of the resource adequacy of the system with the Customer's load and resources
11 from the RFP. The purpose of this would be to not only evaluate the economics of the bids
12 received, but to also see what the makeup of the renewable resources is between solar and
13 wind resources and what influence the composition of the portfolio has on the Company's
14 resource adequacy position. This will help to refine the resource adequacy analysis
15 presented by the Company.

16 **Q. Does that complete your testimony?**

17 **A. Yes.**

MS. DUCKWORTH: Thank you, your Honor.

At this time, on behalf of MEICEO, I move to bind into the record the Direct Testimony Lee Shaver, consisting of a cover page, a table of contents, and 31 pages of questions and answers. I also move for the admission of Mr. Shaver's Testimony Exhibits MEICEO-18 through MEICEO-31, of which Exhibits MEICEO-20, 24, 25, and 31 are Confidential.

JUDGE STALEY: All right. Any objection to the binding in of the prefiled Direct Testimony of Lee Shaver, as well as the admission of Exhibits MEICEO-18, MEICEO-19, Confidential MEICEO-20, Exhibit MEICEO-21 through 23, Confidential MEICEO-24 and 25, Exhibit MEICEO-26 through 30, and Confidential MEICEO-31?

Hearing none, the prefiled Direct Testimony of Lee Shaver is bound into the record, and Exhibit MEICEO-18 through 31 are admitted into evidence, with MEICEO-20, 24, 25, and 31 being Confidential.

(Direct Testimony bound in.)

- - -

**STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION**

In the matter of the application of DTE	)	
ELECTRIC COMPANY for approval of	)	Case No. U-22058
special contracts and for other relief.	)	

DIRECT TESTIMONY OF

LEE SHAVER

ON BEHALF OF

**THE MICHIGAN ENERGY INNOVATION BUSINESS COUNCIL, INSTITUTE FOR
ENERGY INNOVATION, ECOLOGY CENTER, ENVIRONMENTAL LAW & POLICY
CENTER, UNION OF CONCERNED SCIENTISTS, AND VOTE SOLAR**

June 5, 2026

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1 **I. INTRODUCTION AND SUMMARY**

2 **Q: Please state your name and business address.**

3 A: My name is Lee Shaver. My business address is 200 East Randolph Street, Suite 5151,
4 Chicago, IL 60601.

5 **Q: By whom are you employed and in what capacity?**

6 A: I am employed by the Union of Concerned Scientists (“UCS”) as a Senior Energy Analyst.
7 In this role, I focus on research and analysis of state and regional energy system
8 transformation to support increasing shares of renewable energy and distributed energy
9 resources. My work contributes to UCS’s efforts to reform wholesale electricity market
10 designs to increase market share of clean energy technologies. I also contribute to UCS’s
11 state-focused efforts for policies that enhance equity and enable clean energy technologies,
12 including distribution grid planning and energy storage.

13 **Q: Please describe the Union of Concerned Scientists.**

14 A: The Union of Concerned Scientists was founded in 1969 by scientists and students of the
15 Massachusetts Institute of Technology. UCS employs scientists, analysts, and engineers to
16 develop and implement innovative, practical solutions to some of the most pressing
17 problems that society faces today—from developing sustainable ways to feed, power, and
18 transport humanity, to reducing the threat of nuclear war. UCS’s mission is to put rigorous,
19 independent science to work by combining technical analysis and effective advocacy to
20 create policy solutions for a healthy, safe, and sustainable future.¹

¹ For more information, including UCS’s history and mission statement, visit: <https://www.ucs.org/about-us>.

1 **Q: Please describe your educational background.**

2 A: I hold a Master of Science degree in Electrical Engineering from the University of
3 Wisconsin-Madison, conferred in May 2017. I also have a Bachelor of Science degree in
4 Electrical Engineering from LeTourneau University, conferred in December 2007.

5 **Q: Please describe your work experience and professional background.**

6 A: Prior to joining UCS in January 2024, I was an energy engineer for six years with
7 Slipstream, a non-profit focused on building decarbonization and electrification. In this
8 role I designed and conducted research on grid edge technologies including microgrids,
9 grid-interactive efficient buildings, energy management information systems, and
10 refrigeration thermal energy storage. During my graduate program, my research focused
11 on developing and testing hardware and software for small-scale, remote microgrids.
12 Earlier in my career, I served in various engineering roles for over five years at Quadlogic,
13 a manufacturer of electric metering equipment. My resumé, including a list of publications,
14 is attached to this testimony as Exhibit MEICEO-18.

15 **Q: Have you previously testified before this Commission as an expert?**

16 A: Yes. I provided testimony before the MPSC in the following cases:

- 17 • U-21482, DTE Electric Company Interconnection Procedures
- 18 • U-21816, Consumers Energy Company's Renewable Energy Plan
- 19 • U-21870, Consumers Energy Company's Rate Case
- 20 • U-21986, Indiana Michigan Power Company Large Power Tariff

21
22 **Q: Have you provided testimony or comments in other proceedings or venues?**

23 A: I have prepared or assisted with preparation of testimony and comments in stakeholder
24 venues involving the Michigan Public Service Commission, the Illinois Commerce
25 Commission, the Wisconsin Public Service Commission, and the Federal Energy
26 Regulatory Commission.

1 **Q: Are you sponsoring any exhibits?**

2 **A:** Yes, I am sponsoring the following exhibits:

- 3 • Exhibit MEICEO-18: Resumé of Lee Shaver
- 4 • Exhibit MEICEO-19: DTE response to AGDE-2.50b
- 5 • Exhibit MEICEO-20: Confidential DTE response to CEOMEIBCIEIDE-
- 6 1.12
- 7 • Exhibit MEICEO-21: DTE responses to CEOMEIBCIEIDE-1.28a and
- 8 1.28ai
- 9 • Exhibit MEICEO-22: DTE response to CEOMEIBCIEIDE-2.1d
- 10 • Exhibit MEICEO-23: DTE responses to CEOMEIBCIEIDE-1.37b and
- 11 1.38a
- 12 • Exhibit MEICEO-24: Confidential DTE response CEOMEIBCIEIDE-2.1c
- 13 (S1)
- 14 • Exhibit MEICEO-25: Confidential DTE response to MNSDE-1.10a
- 15 • Exhibit MEICEO-26: DTE response to CEOMEIBCIEIDE-1.39a and 1.39b
- 16 • Exhibit MEICEO-27: DTE response CEOMEIBCEIDE-3.2
- 17 • Exhibit MEICEO-28: Elevate Energy Consulting & GridLab, Practical
- 18 Guidance and Considerations for Large Load Interconnections (May 2025)
- 19 • Exhibit MEICEO-29: North American Electric Reliability Corp.,
- 20 Characteristics and Risks of Emerging Large Loads White Paper (July
- 21 2025)
- 22 • Exhibit MEICE-30: North American Electric Reliability Corp., Assessment
- 23 of Gaps in Existing Practices, Requirements, and Reliability Standards for
- 24 Emerging Large Loads White Paper (March 2026)
- 25 • Exhibit MEICEO-31: Confidential DTE response to CEOMEIBCEIDE-4.1

26

27 **II. PURPOSE OF TESTIMONY**

28 **Q: On whose behalf are you appearing in this case?**

29 **A:** I am testifying on behalf of the Ecology Center, Environmental Law & Policy Center,

30 Union of Concerned Scientists (“UCS”), and Vote Solar, collectively the “Clean Energy

31 Organizations” or “CEO,” as well as the Michigan Energy Innovation Business Council

32 and the Institute for Energy Innovation. I will refer to these organizations collectively as

33 “MEI/CEO”.

34

35

1 If the Company does not provide these details in rebuttal, then I recommend that
2 the Commission deny approval of the application until DTE is able to demonstrate that it
3 has or will sufficiently address these reliability risks.

4 **III. EMISSIONS AND CLEAN ENERGY IMPACTS OF THE PROPOSED DATA**
5 **CENTER**

6 **Q: What are Google’s clean energy goals?**

7 A: In a report published in June 2025, Google states “[w]e aim to run on 24/7 carbon-free
8 energy on every grid where we operate by 2030.”² Google characterizes this as a “carbon-
9 free energy moonshot,” defining “moonshots” as “environmental ambitions that may seem
10 impossible at the time we set them.”³ Google then describes challenges to accomplishing
11 its “moonshots,” including rapidly growing demand from data centers like the project
12 proposed in the instant case. Summarizing these challenges, the report states:

13 These external factors could affect the cost, feasibility, and timeline of our
14 progress—and navigating them requires flexibility. To maintain momentum
15 toward our climate moonshots, we’ll continue to evaluate a broad range of
16 solutions, balancing cost, quality, and the speed of emissions reductions.

17 While continuing to support a goal of hourly matching by 2030,⁴ it is clear that
18 Google does not have full confidence in its ability to meet this objective in the near term,
19 due to factors both within and outside its control.
20
21
22

² Google, *Google Environmental Report 2025*, June 2025, 79, <https://sustainability.google/google-2025-environmental-report/>.

³ Ibid., 78.

⁴ Ishika Mookerjee and Alastair Marsh, “Google Executive Says ‘Moonshot’ Clean Energy Goal Is Intact,” *Bloomberg.Com*, May 19, 2026, <https://www.bloomberg.com/news/articles/2026-05-19/google-executive-says-moonshot-clean-energy-goal-is-intact>.

1 **Q: Does Google have an interim goal or objective prior to achieving 24/7 carbon-free**
2 **energy?**

3 A: Yes. Prior to meeting this goal, Google has committed, since 2017, to annual matching,
4 where local energy use provided by fossil fuels is matched with purchases of wind and
5 solar energy.⁵

6 **Q: What is the difference between annual matching with wind and solar and 24/7 carbon-**
7 **free energy?**

8 A: There are two differences. First, with an annual matching goal, there are still times during
9 which Google runs on fossil fuel energy for part of the day, as Google explains:

10 Even if a company buys clean energy in bulk and applies it to match its total
11 usage over the course of the year, its real-time energy mix likely includes
12 electricity generated from fossil fuels.⁶

13 Under hourly matching, reliance on fossil fuels is greatly reduced, as Google must
14 match [its] electricity use with clean energy generated locally and in real
15 time—matching electricity consumption with clean power generation on the
16 same grid, in the same hour.⁷

17
18 The second difference is in the type of energy which Google is seeking to match
19 under each objective. While the annual matching goal is narrowly focused on wind and
20 solar energy, the longer-term goal broadens the criteria to include all sources of “carbon-
21 free” energy, which Google defines as

22 types of electricity generation that don’t directly emit carbon dioxide,
23 including solar, wind, geothermal, hydropower, and nuclear. In addition,
24 when deployed with the appropriate guardrails, low-carbon technologies
25 including sustainable biomass and carbon capture and storage can contribute
26 to a CFE portfolio. Energy storage systems can contribute as well.⁸
27

⁵ Google, *Google Environmental Report 2025*, 4.

⁶ Ibid., 29.

⁷ Ibid., 30.

⁸ Ibid., 103.

1 **Q: What is your opinion of these two goals?**

2 A: In order to address the ongoing climate crisis and the need to transition to 100% clean
3 energy, these goals represent a positive step in the right direction. Although I take issue
4 with some aspects of Google’s and DTE’s plan as discussed below, I believe these goals
5 are directionally correct, and that more companies should be implementing and working
6 towards similar goals. A recent report found that only a handful of technology companies
7 are working towards hourly matching (if they have clean energy goals at all), and that
8 Google has demonstrated engagement in industry conversations around strategies for
9 achieving (and importantly, verifying) hourly clean energy matching.⁹

10 Thus, the intent of my testimony here is not to criticize Google’s plan as
11 documented in DTE’s application in the instant case, but to clarify the specific claims, and
12 whether and how they are being achieved for this particular project. Once the claims, the
13 realities, and the impact are clear, I offer recommendations for DTE to fully support Google
14 in achieving these goals. In short, while Google has the right goals, in this case it is not
15 doing enough, quickly enough, for its actions to match its stated intentions.

16 **Q: What has Google publicly stated about its clean energy goals for this project?**

17 A: For this project, Google has not indicated specific objectives related to either its 24/7
18 carbon-free energy or 100% annual matching goals. In a blog post, Google described the
19 clean energy investments tied to the project as follows:

20 Google’s data center operations will be served by 2.7 gigawatts (GW) of new
21 resources for the grid, including solar power, advanced storage technologies
22 and demand flexibility. This Clean Capacity Acceleration Agreement with
23 DTE (the same structure as the Clean Transition Tariff) will bring new, clean

⁹ InfluenceMap, *Technology Sector Engagement on the Greenhouse Gas Protocol: Analysis of the Sector’s Engagement with Global Emissions Accounting Standards*, October 2025, <https://influencemap.org/report/Technology-Sector-Engagement-on-the-GHG-Protocol-Scope-2-Revision-Process-33675>.

resources online, while supporting the state’s transition away from coal-fired power.¹⁰

The Clean Capacity Accelerator Agreement provides the specifics of these resources, all built on DTE’s grid: 1.6 GW of renewables, up to 450 MW of energy storage (including 50 MW of long-duration storage), and 250 MW of demand response.¹¹ Note that the demand resource is only contractually obligated through 2033.¹² While not a subject of my testimony here, MEICEO Witness Hotaling recommends possible extension of this resource, which would also support Google’s long-term climate objectives.

Q: Does DTE indicate if Google is seeking to achieve either of these goals in the instant case?

A: Yes. While DTE’s testimony does not include mention of the 24/7 carbon-free matching goal, the Company does indicate it is supporting Google’s 100% renewable annual matching claim, as I discuss below.

Q: How does DTE propose to support Google in meeting its annual matching goal in the current case?

A: The Company proposes that:

By allocating 1.6 GW to a VGP Special Contract, the Customer may claim 100% renewable energy usage once the Company hits the 60% RPS target.¹³ In support of this reasoning, Witness Bilyeu provides Table 1, reproduced below:

Table 1 Customer Build to Support 100% Renewable Energy Claim¹⁴

¹⁰ Will Conkling, “Scaling Clean Energy and Reliability in Michigan,” *Google*, March 17, 2026, <https://blog.google/innovation-and-ai/infrastructure-and-cloud/global-network/clean-energy-reliability-michigan/>.

¹¹ DTE Electric Company, Direct Testimony and Exhibits of Witness Shawn D. Burgdorf, Docket U-22058 (MPSC March 17, 2026), 9–10.

¹² *Ibid.*, 11.

¹³ DTE Electric Company, Direct Testimony and Exhibits of Witness Kevin L. Bilyeu, Docket U-22058 (MPSC March 17, 2026), 9.

¹⁴ *Ibid.*

Customer Load	7,884 GWh
Converted to GW	4.0 GW
Renewable Energy from RPS by 2035	60%
Gap from RPS and 100% Renewable Energy Target	40%
VGP GW to achieve 100% Renewable Energy	1.6 GW

In footnotes, Witness Bilyeu explains that 7,884 GWh is calculated based on the facility's load factor of 90%,¹⁵ and that 4.0 GW represents the amount of solar photovoltaic capacity, at a capacity factor of 22.5%, needed to supply 7,884 GWh worth of customer load with 100% renewable energy annually.

While not going into detail, Witness Bilyeu is arguing that because 60% of the energy provided by DTE's grid will come from renewable sources by 2035 (presuming DTE's continued compliance with the RPS), Google only needs to allocate 40% of its usage to renewables through the VGP Special Contract (the terms of which are incorporated into the CCAA) to reach a 100% renewable target.

Q: Do you agree that this approach will result in Google reaching 100% renewable energy for the proposed facility?

A: It is not clear from DTE's testimony whether this is a valid approach. Witness Bilyeu seems to be describing an approach commonly used by many companies to support a claim of 100% renewable on an annual matching basis, whereby they purchase sufficient renewable energy credits to offset the portion of their energy usage from the grid which is not renewable.¹⁶ In order for this approach to be valid, Google would need to purchase 100%

¹⁵ While the testimony indicates a load factor of 88.5%, Witness Bilyeu clarified in discovery response ADGE-2.50b (included as Exhibit CEO-19) that this was stated in error, and that the correct load factor is 90% which was in fact used for the calculation.

¹⁶ Mike Scott, "Big Tech Splits over Proposed Shake up of Clean Energy Accounting," *Reuters*, May 26, 2026, sec. Climate & Energy, <https://www.reuters.com/sustainability/climate-energy/big-tech-splits-over-proposed-shake-up-clean-energy-accounting--ecmii-2026-05-26/>.

1 of its energy directly from DTE (thereby receiving 60% renewable energy), and then
2 additionally purchase 40% worth of RECs equivalent to the non-renewable portion of what
3 it receives from DTE. In other words, Google would need to buy all of its energy from
4 DTE, and then buy additional RECs to offset the non-renewable portion of the energy it
5 receives from DTE.

6 However, if Google is purchasing 40% of its energy through the VGP contract, it
7 is only receiving 60% its energy from DTE, and, in turn, only 60% of that grid-supplied
8 portion is renewable. This means that Google is only matching 76% of its usage with
9 renewables:

$$10 \quad [(60\% \times 60\%) = 36\%] + 40\% = 76\%$$

11 In rebuttal, I recommend that the Company provide additional detail about the VGP
12 Special Contract and associated transfer of RECs to clarify how Google will achieve 100%
13 annual matching.

14 **Q: What other concerns do you have about this approach?**

15 A: Even assuming that DTE is correctly applying this approach in the instant case, three
16 additional important caveats also apply. First, because the data center will come online
17 before the 1.6 GW of renewables are built and before DTE reaches the 60% RPS target,
18 the facility will not achieve annual matching for the first six years of operation. Second,
19 DTE's ability to bank and purchase RECs as a means of meeting its RPS obligations means
20 that the actual share of renewables on the grid in 2035 may be less than 60%.

21 The final issue points to the importance of Google's longer term goal for hourly
22 matching: even if the above caveats were resolved and we could confidently say Google
23 was achieving annual matching, the day-by-day and hour-by-hour mismatch between the

1 facility's demand and the supply of renewable energy means that it will still result in
2 combustion of fossil fuels, because it is connected to and depends on a grid partly supplied
3 by fossil energy.

4 **Q: Did you perform any analysis to estimate the impacts of these shortcomings?**

5 A: Yes. I conducted two different analyses to understand the emissions and clean energy
6 impacts of the proposed facility, using modeling results provided by DTE in response to
7 CEOMEIBCIEIDE-1.12.

8 The first analysis, which I'll refer to as the annual analysis, looked directly at the
9 annual renewable share and emissions attributable to the proposed facility, using two
10 spreadsheets provided by DTE. First, in spreadsheet NDA U-22058 CEOMEIBCIEIDE-
11 1.12 DC2 Output Reports CONFIDENTIAL.xlsx, sheet 'Resource Monthly,' DTE
12 provides modeled monthly generation data from 2028 through 2038 for each resource in
13 its fleet, including the type of resource, generation in MWh, system curtailed in MWh, and
14 heat required in mmBtu. Second, in spreadsheet NDA U-22058 CEOMEIBCIEIDE-1.12
15 DC2 PC Inputs CONFIDENTIAL.xlsx, sheet 'Resource Emission,' DTE provides CO₂
16 emissions rates in lbs/mmBtu of each individual resource in its generating fleet. "DC2" in
17 the filename of each spreadsheet indicates that these spreadsheets represent a modeling
18 scenario including the load from two data centers approved or proposed in DTE's territory
19 – the 1.4 GW Oracle facility approved in Case No. U-21990 and the Google facility in the
20 instant case.

21 First, I used these data to calculate the following quantities in order to estimate the
22 actual share of renewables on DTE's grid, and the carbon emissions rate:

- 23 • Net monthly generation per resource in GWh, equivalent to generation
24 minus system curtailed, divided by 1000. To exclude storage charging and

discharging from the calculations, I set net generation from storage to zero at this step.¹⁷

- CO₂ emissions in short tons, equivalent to heat required (mmBtu) times CO₂ emissions rate (lbs/mmBtu), divided by 2000.

Next, I created a monthly summary table including the following columns:

- Customer GWh, equivalent to the product of customer demand in MW, hours per month, and the expected load factor of 90%. Customer demand was taken from Figure 1 in Witness Foley's revised testimony and was calculated both for the slowest and fastest ramping schedules.¹⁸
- VGP GWh, the total generation from the 1.6 GW of renewables funded by Google. This was modeled by DTE as solar PV with a capacity factor that varies by month and year.
- DTE renewable GWh, the total generation from all other renewable resources (predominantly wind and solar).
- DTE other GWh, the total generation from all other resources, including coal, non-renewable contract purchases, gas, oil, nuclear,¹⁹ and other.

With those quantities calculated, I was able to determine on an annual basis the total share of DTE's monthly generation that is renewable, the share of Google's load that is supplied by renewables, and the emissions resulting from that part of Google's load not supplied by renewables.

For the second analysis, which I'll refer to as the base case comparison, I compared the company's "DC2" scenario to the "base case" which excludes the proposed facility (but still includes the 1.4 GW Oracle facility and related 1.8 GW of solar in Case No. U-21990).²⁰ To conduct this analysis, I simply duplicated the analysis above, removed the

¹⁷ While storage can be used to reduce overall emissions (for example, by reducing curtailment from renewables) DTE's modeling does not provide sufficient data to determine what resources were used to store energy. Total generation from storage over the 10 modeled years is 71,135 GWh, or less than 10% of overall generation. Thus, even if all storage were dedicated to reducing emissions (which is highly unlikely), the impact on the final analysis would be less than 10%.

¹⁸ DTE Electric Company, Revised Direct Testimony of Witness Neal T. Foley, Docket U-22058 (MPSC April 10, 2026), 16.

¹⁹ While nuclear energy would count towards Google's 24/7 carbon-free energy goal, I am not distinguishing it in this analysis to focus on DTE's claim of 100% renewable matching by 2035.

²⁰ DTE Electric Company, Direct Testimony and Exhibits of Witness Kevin L. Bilyeu, Docket U-22058 (MPSC March 17, 2026), 11.

input data from DTE’s “DC2” case, and replaced it with input data from the base case. This enables a direct comparison between annual renewable share and emissions between DTE’s modeled scenarios with and without the proposed facility.

Q: Please summarize the results of your annual analysis.

A: The table below summarizes my findings on an annual basis for the slow ramp scenario:²¹

Year	Customer GWh	VGP GWh	DTE renewable share	Customer renewable share	Customer emissions tons
2028	0	0	27%		0
2029	626	0	36%	36%	209,601
2030	6,396	878	43%	56%	1,570,483
2031	7,884	2,235	45%	73%	1,574,841
2032	7,906	3,124	49%	89%	1,289,604
2033	7,884	3,197	47%	88%	1,068,728
2034	7,884	3,185	52%	93%	884,525
2035	7,884	3,093	53%	92%	941,819
2036	7,906	3,173	57%	97%	877,160
2037	7,884	3,159	56%	96%	847,430
2038	7,884	3,208	59%	99%	747,493

The column labeled “DTE renewable share” shows the actual share of renewable energy achieved by DTE in the given year, which is calculated differently than RPS requirements, as I will discuss below. The column labeled “Customer renewable share” is the sum of “DTE renewable share” and the share of the customer’s load supplied by the renewable VGP in that year. This represents Google’s clean energy share following the traditional annual matching approach.

²¹ Additional columns showing intermediate calculations, and results for the fast ramp scenario, are included in Exhibit CEO-3.

1 The final column, customer emissions tons, represents the impact of the difference
2 between the accounting approach to annual matching, and the physical reality: short tons
3 of CO₂ emissions attributable to the non-renewable portion of energy Google receives from
4 DTE's grid. Although the annual matching approach offsets the non-renewable energy
5 Google buys from the grid, this column shows the actual emissions, reinforcing why
6 Google's long-term goal of 24/7 matching is important.

7 **Q: Explain the discrepancy between the RPS requirement of 60% in 2035 and the lower**
8 **value you calculated above.**

9 A: Two factors lead to this discrepancy. The first has to do with how the state's clean energy
10 law (Public Act 235) allows DTE to claim renewable energy credits ("RECs") in a given
11 compliance year. The second relates to the total against which the renewable percentage is
12 being calculated.

13 As Witness Bilyeu explains, RECs that are not needed for compliance in a given
14 year may be "banked" for up to five years after they are generated.²² These banked RECs
15 can then be used for compliance with DTE's RPS requirement even though they were
16 generated in a previous year. In addition, DTE can also comply through the purchase of
17 RECs, as explained by Witness Bilyeu and indicated on lines 23 and 24 of Exhibit A-2.

18 The updated Exhibit A-2 (provided in discovery response CEOMEIBCIEIDE-3.2
19 and included as Exhibit MEICEO-27) shows that in 2035, DTE purchases roughly 1.5
20 million RECs (line 40), and that the REC balance decreases from roughly 3.6 million (line
21 37) to 2.7 million (line 45), indicating that DTE expects it will not generate enough RECs
22 in 2035 and will instead use some banked RECs to meet compliance.

²² DTE Electric Company, Direct Testimony and Exhibits of Witness Kevin L. Bilyeu, Docket U-22058 (MPSC March 17, 2026), 6. Ibid.

1 Because of this ability to use banked and purchased RECs, the actual amount of
2 renewable energy DTE generates in a given year may be either higher or lower than its
3 RPS requirement for that year. For example, the use of purchased and banked RECs
4 described above means that in 2035, DTE will generate less renewable energy than its RPS
5 requirement.

6 The second, smaller source of discrepancy between my calculation and DTE's 60%
7 requirement is that I calculated the renewable share based on total generation and
8 purchases—all of the energy which DTE procures per year—while PA 235 only applies to
9 retail sales, or the total amount of energy sold to DTE's customers. This excludes
10 transmission and distribution losses, and energy generated by DTE and sold on the
11 wholesale market. Retail sales also exclude VGP sales and outflow from distributed
12 generation customers, as detailed on lines 9 and 11 of Exhibit MEICEO-27.

13 **Q: What does this discrepancy mean in regards to Google's annual matching goal?**

14 A: The use of banked RECs means that prior to 2035, some portion of the renewable energy
15 that could be counted towards Google's clean energy goal under an RPS-based approach
16 was actually generated before Google was a customer of DTE. After 2035, the use of
17 banked RECs complicates Google's ability to strictly meet an annual matching goal.

18 The use of purchased RECs means that some portion of the renewable energy
19 Google is counting towards its goal is coming from outside of DTE's grid. The difference
20 in baseline (total generation vs retail sales) further complicates Google's ability to confirm
21 annual matching.

22 While these facts do not necessarily discredit Google's claim to be 100% renewable
23 on an annual basis following the conventional approach, they are important caveats that

1 must be tracked and accounted for. As I discussed above, Google's ultimate goal, which I
2 directionally support, is to reach 24/7 carbon free energy. My analysis here simply
3 demonstrates the shortcomings of an annual matching approach that is built on Michigan's
4 renewable portfolio standard, and specific nuances around the REC accounting on which
5 it is based. Rather than being a criticism of PA 235, it is instead an endorsement of the 24/7
6 matching approach, and an illustration of why Google and DTE should be prioritizing that
7 approach.

8 **Q: What does this analysis indicate about the first six years of the facility's operation?**

9 A: There are two components to Google's strategy to reaching 100% annual renewables: 40%
10 generation from renewable VGP, and 60% renewables from DTE's grid. Neither of these
11 pieces are fully in place in the first few years of the data center's operation.

12 The facility ramps up to full load from 2029 to 2030, while the associated renewable
13 VGP does not begin generating until 2030, only reaching full output in 2032. Thus for the
14 first three years of the data center's operation, including nearly two years of full demand,
15 the 40% VGP component is not in place. Once this component is online, DTE still does
16 not reach its 60% RPS target for another three years.

17 As a result, averaged across the six years, the facility's actual renewable share is
18 73%, and total emissions during this period attributable to the data center are approximately
19 6.5 million short tons of CO₂.

20 **Q: What does the analysis indicate about the overall emissions impact of the facility?**

21 A: Through 2038, Google's load results in total cumulative emissions of 10 million short tons
22 of CO₂ under the slow ramp scenario, and 14 million short tons under the fast ramp
23 scenario, before any renewable credit matching. To put this in context, DTE's modeling

1 indicates that Monroe units 1 and 2 will produce an average of 8.9 million short tons of
2 CO₂ annually from 2028 until they are retired at the end of 2032. In other words, the first
3 ten years of operation of Google's data center (under either the slow or fast ramp scenarios)
4 result in more total emissions than would be caused by hypothetically delaying the
5 retirement of Monroe units 1 and 2 by an additional year.

6 Even if we only look at the last four years (when the renewable VGP is fully online
7 and DTE has accomplished its 60% renewable requirement), CO₂ emissions still average
8 800,000 short tons annually, demonstrating the shortcomings of the approach that Google
9 is using to claim annual matching and the importance of transitioning to 24/7 matching.

10 **Q: Please summarize the results of your base case comparison. What is the difference in**
11 **total CO₂ emissions from DTE's grid between the DC2 case and the base case without**
12 **the data center and its associated renewables?**

13 A: In the DC2 case, CO₂ emissions from all resources for all 10 years of the analysis total
14 150.2 million short tons, while the total in the base case is 145.8 million short tons. Thus,
15 the scenario with the data center results in approximately 4.4 million short tons more
16 emissions than the scenario without the data center (or associated renewable energy).

17 **Q: Why is this emissions total different than the sum calculated in your annual analysis?**

18 A: The totals are different because of differences between the two scenarios beyond the data
19 center load and associated 1.6 GW. Table 1 in the testimony of Witness Burgdorf shows
20 that in the data center case, 250 less MW of renewable capacity are needed, and 727 MW
21 of "Proxy CCGT w/CCS" are added. These changes also affect how other resources are
22 dispatched.

23 **Q: What conclusions do you draw from the base case comparison?**

1 A: This comparison demonstrates that while construction of the VGP renewables (modeled as
2 solar) does reduce emissions compared to the data center being powered by DTE's grid
3 alone, the Company's own modeling shows that a scenario with the data center still results
4 in more overall emissions than a scenario without the data center (or associated solar) over
5 the first 10 years.

6 **Q: What conclusions do you draw from these results overall?**

7 A: These results reinforce the importance of a goal like Google's 24/7 carbon-free energy
8 target, as they underscore the complexities of calculating an annual matching goal, and
9 illustrate the increased emissions that can result from an annual matching goal compared
10 to hourly matching.

11 **Q: Based on these conclusions, what do you recommend?**

12 A: Given Google's commitments to achieve 24/7 carbon-free energy by 2030, and 100%
13 renewable energy on an annual basis prior to 2030, I recommend that DTE do more to
14 support its customer in achieving these objectives.

15 To address the shortcomings of DTE's and Google's current plan to achieve 100%
16 renewable energy discussed above, the Company should explore additional means to add
17 Google-funded renewables to its grid. This could mean increasing the portion of its load
18 served through the VGP program, and/or pursuing the VPPs and customer-sited resources
19 proposed by MEI/CEO Witness Sherman in this proceeding. These recommendations
20 could allow Google to reach its 100% annual matching target on the timeline it has
21 committed to, while setting the stage for Google to reach its longer-term 24/7 carbon-free
22 energy goal.

1 **IV. RELIABILITY IMPACTS OF THE PROPOSED DATA CENTER**

2 **A. *Background***

3 **Q: Do large loads like the proposed facility pose reliability risks to the grid?**

4 A: Yes. Large data centers pose two specific categories of reliability risks to the grid. The first
5 is the risk of insufficient resource adequacy, and the second is risk of grid disturbances
6 caused by the unique electrical behavior of data centers, which may lead to outages and/or
7 damage to grid infrastructure. The risk of insufficient resource adequacy is covered by the
8 testimony of MEI/CEO Witnesses Kenworthy and Hotaling in this proceeding. In this
9 section, I will focus on the reliability risks posed by the electrical behavior of data centers.

10 **Q: Have you testified about these risks previously?**

11 A: Yes. In Case No. U-21986, the application of Indiana Michigan Power Company (“I&M”) for approval of changes to its tariff covering large loads, I testified extensively about these
12 reliability risks.²³

14 **Q: Please summarize the key reasons why large loads such as data centers pose grid reliability risks.**

16 A: There are five characteristics of large data centers that pose unprecedented and unique risks
17 to grid reliability:²⁴

- 18 • **Size.** Large data centers currently seeking interconnection exceed historical
19 large loads by orders of magnitude. In the instant case, the single proposed
20 customer will increase DTE’s load by nearly 15%.²⁵
- 21 • **Prevalence.** While historically large loads were few and far between, the
22 rate of interconnection requests from large data centers is increasing rapidly
23 – the instant case represents the second request in less than a year for
24 interconnection of a GW-scale facility in DTE’s territory (the first being

²³ CEO, Revised Direct Testimony and Exhibits of Lee Shaver, Docket U-21986 (MPSC March 17, 2026).

²⁴ Exhibit MEICEO-28.

²⁵ DTE Electric Company, Direct Testimony and Exhibits of Witness Shawn D. Burgdorf, Docket U-22058 (MPSC March 17, 2026), 21. “‘Base case’ [...] load forecast is 53,182 GWh [...] [I]n the ‘Customer datacenter case’ [...] load increases to 61,819 GWh.” (61,819 / 53812) – 1 = 14.9%.

Case No. U-21990). DTE has further indicated that up to an additional 7 GW are possible in the near term.²⁶

- **Lack of data transparency.** To reliably accommodate a grid with such large loads, grid planners and operators need detailed and continuous data about the facilities, which has been challenging to obtain due to data gaps, concerns about security, and lack of enabling regulation.
- **Load characteristics.** The high variability, large power swings, and harmonic impacts of data centers pose significant challenges to the grid.
- **Sensitivity to grid disturbances.** Data centers are typically interconnected to the grid through uninterruptible power supplies (“UPS”) which are programmed to be very sensitive to fluctuations in grid voltage and frequency, and can disconnect quickly when they detect a grid disturbance. Rapid disconnections of large loads from the grid are known to trigger even greater disturbances,²⁷ and the risk will only increase as the prevalence of data centers increases.

The overall impact of these five characteristics was summarized by the North

American Electric Reliability Corporation (“NERC”) last year in the report

“Characteristics and Risks of Emerging Large Loads,” included as Exhibit MEICEO-29:

Large loads pose risks in both the planning and operations horizons. Their quick interconnection timelines and large peak demands drive generation and transmission adequacy risks. The fast ramp rates and variability of the loads could exhaust reserves for balancing and contribute to voltage and frequency instability. If system planners and operators lack accurate dynamic models, they may be unable to predict ride-through and system behaviors during events. Much of the [power electronics load] can contribute to harmonics and voltage fluctuations. Large loads like data centers can also be susceptible to cyber-attacks that could trigger load ramps. Additionally, the rapid pace of load integration with large loads’ magnitude could negatively impact system resilience. Large loads must be considered in load-shed obligations, [under-frequency load shed] program design, and blackstart restoration.

In the same paper, NERC points out that this challenge is exacerbated by the fact

that “large loads are not required to be NERC registered entities” and thus “are not required

to adhere to Reliability Standards.”

²⁶ Robert Walton, “DTE Energy’s 5-Year Spending Plan Jumps 20% on Data Center, Reliability Investments,” *Utility Dive*, February 17, 2026, <https://www.utilitydive.com/news/dte-spending-plan-data-center-earnings/812305/>.

²⁷ NERC, *Incident Review: Considering Simultaneous Voltage-Sensitive Load Reductions*, January 8, 2025, https://www.nerc.com/pa/rrm/ea/Documents/Incident_Review_Large_Load_Loss.pdf.

1 **Q: What did you recommend in Case No. U-21986 to address these grid reliability risks?**

2 A: I made two recommendations that are relevant to the instant case. First, I recommended
3 that the Commission create a large load interconnection working group to develop a set of
4 requirements for interconnection of large loads, and propose a pathway to implement these
5 requirements. Second, I recommended that I&M implement two specific requirements,
6 voltage ride-through and operational ramp rate limits, prior to any findings or
7 recommendations from the working group I proposed. I highlighted how these two specific
8 requirements are important to address many of the near-term risks caused by large loads,
9 and are relatively straightforward to implement.

10 My recommendations were based on the grid reliability impacts of large data center
11 customers, which I outlined above, as well as findings and recommendations from NERC,
12 and other efforts to address these risks at the transmission operator level (ATC),²⁸ the state
13 level (Texas),²⁹ and the regional level (SPP).³⁰

14 **Q: What is the current status of Case No. U-21986?**

15 A: The Administrative Law Judge issued a proposal for decision (“PFD”) in the case last
16 month, with exceptions and replies to exceptions due June 9 and June 23, respectively.³¹
17 While an order has not been issued, the PFD supports both of the relevant recommendations
18 from my testimony in the case. First, the PFD recommended that

²⁸ ATC, “Transmission System Planning Criteria,” Criteria (ATC, August 28, 2025), <https://cdn.misoenergy.org/ATC%20TO%20Planning%20Criteria108210.pdf>; ATC, “Load Interconnection Guide,” August 22, 2025, https://www.atcllc.com/wp-content/uploads/Load-Interconnection-Guide_Rev-15_Final_082225.pdf.

²⁹ Phil King et al., “Relating to the Planning for, Interconnection and Operation of, and Costs Related to Providing Service for Certain Electrical Loads and to the Generation of Electric Power by a Water Supply or Sewer Service Corporation,” Pub. L. No. SB6 (2025), <https://legiscan.com/TX/bill/SB6/2025>.

³⁰ Federal Energy Regulatory Commission, Order Accepting Tariff Revisions, Subject to Condition re Southwest Power Pool, Inc., Docket ER26-247-000 (FERC January 14, 2026).

³¹ Administrative Law Judge, Proposal for Decision, Docket U-21986 (MPSC May 19, 2026).

1 the Commission establish a large load workgroup [...] to address the
2 reliability impacts of large load customers on the grid, review existing data
3 to understand the technical challenges of interconnecting large loads, follow
4 efforts elsewhere, discuss how Michigan’s approach should relate to and
5 interact with standards or recommendations from NERC, FERC, MISO, and
6 PJM, identify best practices for large load interconnection, develop a set of
7 proposed technical requirements for the interconnection of large loads, and
8 provide a roadmap for implementation of the requirements.³²

9
10 Second, the PFD recommended that I&M update its requirements “to improve its
11 voltage ride-through requirements and add operational ramp rate limits.”³³

12 **Q: Have there been additional developments since you filed testimony in Case No. U-**
13 **21986 related to the reliability impacts of data centers?**

14 **A:** Yes, there have been a number of developments which only serve to bolster my previous
15 testimony and recommendations.

16 First and foremost, on May 4, 2026, NERC issued a level three alert (its highest
17 level alert, and only the third such in its history) including seven “essential actions” to be
18 taken by utilities “to address the risks posed by existing and new computational loads
19 interacting with the bulk power system (BPS).”³⁴ These essential actions focus on planning,
20 modeling, study, and data collection (actions 1, 2, 6, and 7) related to large load
21 interconnection and behavior, as well as implementing specific processes to improve
22 handling of reliability risks (actions 3, 4, and 5). While the alert falls short of
23 recommending specific requirements, it lays the groundwork for implementation of future
24 reliability requirements. To wit, just before issuing the level three alert, NERC launched

³² Ibid., 99–100.

³³ Ibid., 97.

³⁴ NERC, “Essential Action to Industry: Computational Load Modeling, Studies, Instrumentation, Commissioning, Operations, Protection, and Control,” Level 3 Alert, (May 4, 2026), 1, <https://www.nerc.com/globalassets/programs/bpsa/alerts/level-3-computational-load-alert.pdf>.

1 efforts as part of its long-term goal of requiring large loads to be registered entities, and
2 thus subject to reliability standards.³⁵

3 The level three alert followed the publication, in March, of aggregate findings from
4 a level two alert which had been issued in September 2025, providing five
5 recommendations and seeking information from utilities about existing processes,
6 procedures, and requirements for large loads. Summarizing responses to the alert, NERC
7 determined that few utilities are appropriately responding to the reliability risks from large
8 loads, as seen in the following conclusions:

9 Many entities at the time of this Alert do not have specific procedures to
10 handle the unique challenges associated with large loads. [...] Many entities
11 report waiting on or coordinating with a separate entity, primarily their ISO
12 or RTO, before changing their procedures to address the reliability concerns
13 in the Recommendations of this Alert. [...] Entities do not have a
14 standardized requirement for operational ramp limits in a post-disturbance
15 state to address the reliability concerns raised in Recommendation 1. [...] Entities generally do not have a commissioning process to address the
16 concerns discussed in Recommendation 3. [...] Entities broadly do not have
17 a direct level of coordination with large load entities as they either do not
18 have large load entities, or a problem arose that prevented communication in
19 their established process. [...] Entities do not have a good way to capture
20 large loads in near-term or long-term transmission planning horizons as
21 recommended in Recommendation 5.³⁶

22
23
24 Two critical NERC whitepapers published in May continue to reinforce these
25 conclusions and the need for registration requirements and reliability requirements:
26 “Assessment of Gaps in Existing Practices, Requirements, and Reliability Standards for
27 Emerging Large Loads”³⁷ and “Risk Mitigation for Emerging Large Loads: Large Loads

³⁵ NERC, “Large Loads Action Plan Q1 2026 Update: Addressing an Emerging Reliability Issue,” April 2026, <https://www.nerc.com/globalassets/initiatives/large-loads-action-plan/llap-quarterly-update-q1-2026.pdf>.

³⁶ NERC, *Aggregated Report on NERC Level 2 Industry Recommendation: Large Load Interconnection, Study, Commissioning, and Operations*, March 17, 2026, 65–66, <https://www.nerc.com/globalassets/programs/bpsa/alerts/2025/aggregated-report-level-2-large-load-interconnection-study-commissioning-and-operations.pdf>.

³⁷ Exhibit MEICEO-30.

1 Working Group Reliability Guideline.”³⁸ A key recommendation of the former, relevant to
2 the instant case, is that

3 Federal and/or state regulators, as applicable, should consider the gaps
4 identified in this paper and coordinate with utilities to assess whether
5 incorporating additional interconnection requirements and/or studies are
6 appropriate to reliably support integration of large loads.³⁹

7
8 Turning to the regional level, MISO, the grid operator for the majority of Michigan,
9 and of which DTE is a part, has also convened a Large Load Working Group. In April, the
10 group gave a presentation recommending four categories of reliability requirements: ramp
11 rate limits, data sharing, ride-through requirements, and stability assessment
12 requirements.⁴⁰ I will discuss these specific recommendations in more detail later in
13 testimony.

14 Finally, the large loads task force of the Energy Systems Integration Group
15 (“ESIG”), a non-profit that convenes technical experts to support grid modernization,
16 continues to publish whitepapers on the topic, including detailed analysis and
17 recommendations. Publications completed since I filed testimony include “Large Load
18 Modeling for Dynamic Studies: Current Practices and Recommendations,”⁴¹ “Large Load
19 Disturbance Events: A Report by the Large Loads Task Force,”⁴² “Historical and Modern

³⁸ NERC, “Risk Mitigation for Emerging Large Loads: Large Loads Working Group Reliability Guideline,” May 2026, https://www.nerc.com/globalassets/our-work/guidelines/reliability/RG_Risk-Mitigation-For-Emerging-Large-Loads.pdf.

³⁹ Exhibit MEICEO-30.

⁴⁰ MISO, “Large Load Interconnection Reliability Requirements,” April 20, 2026, 5, <https://cdn.misoenergy.org/20260420%20LLWG%20Item%2006%20Large%20Load%20Interconnection%20Reliability%20Requirements751448.pdf>.

⁴¹ ESIG, *Large Load Modeling for Dynamic Studies: Current Practices and Recommendations* (ESIG, March 2026), <https://www.esig.energy/wp-content/uploads/2026/03/ESIG-Large-Loads-Modeling-for-Dynamic-Studies-report-2026b.pdf>.

⁴² ESIG, *Large Load Disturbance Events: A Report by the Large Loads Task Force* (ESIG, March 2026), <https://www.esig.energy/reports-briefs/large-load-disturbanceevents/>.

1 Large Loads: Characteristics, Context, and Industry Actions to Meet Grid and Customer
2 Needs,”⁴³ and “Resource Adequacy with Large Loads: Planning for Flexibility to
3 Accelerate Integration.”⁴⁴ Collectively, these reports provide further evidence that large
4 data centers create material risks to grid reliability and resource adequacy, and that utilities,
5 system operators, and regulators are still developing the planning tools, modeling practices,
6 and reliability requirements needed to manage those risks effectively.

7 **B. Interconnection Studies**

8 **Q: What type of study, analysis, or modeling is necessary to address the reliability**
9 **impacts of the proposed data center prior to interconnection?**

10 A: Elevate’s *Practical Guidance and Considerations for Large Load Interconnections*
11 summarizes the importance of reliability analyses, and the types of studies which must be
12 conducted:

13 Utilities must conduct reliability studies when a new large load seeks
14 interconnection to the grid. These studies quantitatively identify whether the
15 large load can be reliably integrated to the [bulk power system] or whether
16 network upgrades are needed to ensure reliable operation within acceptable
17 performance limits. Transmission providers may have a defined study
18 process that outlines how these studies are conducted, and this process may
19 or may not be publicly available for prospective customers.⁴⁵

20
21 Specifically, Elevate recommends that utilities conduct powerflow studies,
22 transient stability studies, electromagnetic transient (“EMT”) studies, and short-circuit
23 studies.⁴⁶

⁴³ ESIG, *Historical and Modern Large Loads: Characteristics, Context, and Industry Actions to Meet Grid and Customer Needs.*, White Paper (Energy Systems Integration Group, March 2026), <https://www.esig.energy/reports-briefs/historical-and-modern-large-loads>.

⁴⁴ ESIG, *Resource Adequacy with Large Loads: Planning for Flexibility to Accelerate Integration*, April 2026, <https://www.esig.energy/reports-briefs/large-loads-resource-adequacy/>.

⁴⁵ Exhibit MEICEO-28.

⁴⁶ Ibid.

1 **Q: What analysis have DTE or others done to understand the specific reliability impacts**
2 **of the proposed data center?**

3 A: It is unclear. In discovery responses CEOMEIBCIEIDE-1.28a and 1.28ai (included as
4 Exhibit CEOMEI-21), Company Witness Benyard indicated that ITC, DTE's transmission
5 provider, conducted "steady-state thermal and voltage analysis, short circuit and stability
6 analysis" to assess the Customer's impact on DTE's grid.⁴⁷

7 However, in a follow-up discovery response, DTE Witness Benyard explained that
8 (emphasis added):

9 these studies are being conducted by ITC or, with respect to the short circuit
10 and stability analysis, *may be conducted in the future* as DTE and ITC
11 continue to conduct studies to develop operating requirements for grid
12 protection.⁴⁸

13
14 No mention is made across testimony or discovery responses of EMT studies.
15

16 **Q: What do you recommend related to these studies?**

17 A: A stability study is a bare minimum for interconnection of the facility. Therefore, I
18 recommend that DTE provide, in rebuttal, the timeline for completing this study.

19 While EMT and short circuit studies are important as well, there may be some cases
20 in which they are less critical than a stability study. I recommend that in rebuttal, DTE
21 either provide the timeline for these studies, or a robust justification as to why they are not
22 needed in the instant case.

23 If the Company does not provide these details, then I recommend that the
24 Commission deny approval of the application until DTE is able to demonstrate that these

⁴⁷ See also Exhibit MEICEO-25.

⁴⁸ Exhibit CEOMEI-31 (emphasis added).

1 studies have been (or will be) conducted, or justify in detail why they are not needed (in
2 the case of EMT and short circuit studies).

3 ***C. Technical Interconnection Requirements***

4 **Q: Has DTE indicated if it will apply specific interconnection requirements to the**
5 **customer to address reliability risks?**

6 A: Yes. While the studies I discussed above are critical to understand the specific risks the
7 facility poses, technical interconnection requirements are also needed to ensure the data
8 center is operated in a manner conducive to ensuring reliability. DTE has indicated it is
9 aware of the importance of establishing such requirements. Specifically, in discovery
10 response CEOMEIBCIEIDE-2.1d (included as Exhibit CEOMEI-22), Witness Benyard
11 states:

12 DTE Electric has historically required new customers to follow a series of
13 operating limits including but not limited to in-rush frequency/magnitude,
14 and power factor. As the Company has learned about the relatively new
15 operating characteristics of certain large data center customers, it was
16 determined that a more robust set of guidelines were required to safeguard
17 the electric system.

18 This awareness is reflected in Section 5.5.2 of the Primary Supply Agreement
19 (“PSA,” Exhibit A-16), which details operating parameters which will be required of the
20 Customer:
21

22 Such Operating Parameters shall include (a) a minimum power factor for the
23 Facility that Company requires Customer to maintain at all times (subject to
24 the occurrence of a Force Majeure Event), (b) constraints on the operational
25 load ramp for load usage fluctuations of the Facility, (c) minimum standards
26 to which Customer's equipment shall conform to minimize harmonic
27 distortions, (d) any requirements for the Facility to remain connected to the
28 grid for voltage and/or frequency conditions, as similarly defined by NERC
29 Reliability Standards, PRC-024, and (e) any other mandatory operating
30 parameters, including but not limited to “low voltage ride-through” and
31 “transient operations”.
32

1 In discovery responses CEOMEIBCIEIDE-1.37b and 1.38a (included as Exhibit
2 CEOMEI-23), Witness Benyard explains that development of the operating parameters
3 will be “subject to input from the Customer, MISO and ITC.”

4 The PSA sets a deadline of 90 calendar days following the contract date; given a
5 contract date of March 12, 2026, this deadline falls on June 10, 2026, though the clause
6 allows that date to be adjusted if “mutually agreed by the parties.”

7 **Q: Has DTE established operating parameters that are sufficient to protect customers**
8 **from the reliability risks associated with the interconnection of Google’s 1 GW data**
9 **center?**

10 A: Based on DTE’s response to CEOMEIBCIEIDE-2.1c (S1) (included as Exhibit CEOMEI-
11 24), the Company has not yet finalized specific operating parameters for this data center.
12 Without seeing the final requirements, I am unable to say.

13 **Q: What specific requirements should DTE implement in this case?**

14 A: I recommend that DTE implement ramp rate limits and ride-through requirements that are
15 consistent with MISO’s current proposed requirements. Specifically, operational ramp
16 rates should be limited to 30 MW per minute,⁴⁹ and voltage and frequency ride-through
17 requirements should be consistent with IEEE 2800 and NERC PRC-029.⁵⁰ While these
18 standards were developed for and apply to inverter-based resources, they provide a valid
19 basis for data center requirements.

20 Because MISO’s requirements have not been finalized, it may be appropriate to use
21 slightly modified requirements, or allow for the requirements specific to Google to be

⁴⁹ MISO, “Large Load Interconnection Reliability Requirements,” 12.

⁵⁰ Ibid., 24.

1 updated in the future, depending on the outcome of MISO's process. However, MISO's
2 proposed requirements have been developed through a stakeholder process with
3 consideration of requirements elsewhere in the industry, and they represent a reasonable
4 starting point.

5 **Q: What are your recommendations related to the operating parameters?**

6 A: Given that the PSA's deadline for finalizing the operating parameters falls after the date of
7 filing direct testimony, but before rebuttal testimony, I recommend that in rebuttal DTE
8 provide the final version of the operating parameters as an exhibit. If these parameters do
9 not closely align with MISO's proposed requirements, then the Company must provide
10 detailed justification for the parameters and how they address the reliability risks the data
11 center poses.

12 If the Company does not provide these details, then I recommend that the
13 Commission deny approval of the application until DTE is able to provide and justify the
14 operational parameters established for the Customer.

15 **Q: Has DTE taken any other steps to minimize the reliability risks of the proposed**
16 **facility?**

17 A: Yes. In Case No. U-21990, as a condition of interconnection of facility proposed in that
18 case, the Commission ordered DTE to update its Emergency Electric Procedures such that

19 the company will shed firm load from the facility operated by Green Chile
20 Ventures LLC prior to shedding firm load of any of DTE Electric Company's
21 other customers to the extent that firm load shedding is directed by the
22 regional transmission organization and shedding firm load of the facility
23 operated by Green Chile Ventures LLC can prevent shedding firm load of
24 other DTE Electric Company customers.⁵¹
25

⁵¹ MPSC, December 18 Order, Docket U-21990 (MPSC December 18, 2025), 44.

1 In Case No. U-22059, DTE updated its procedures as ordered. However, DTE's
2 changes went beyond the Commission's order, such that any large load (defined as either
3 a customer with load greater than 500 MW, or taking service under DTE's large load tariff)
4 be subject to the same load shedding requirements. In the instant case, in discovery
5 response CEOMEIBCEIDE-1.39a (included as Exhibit MEICEO-26) stated that this
6 decision was made as "[t]he Company endeavors to treat all similarly situated customers
7 similarly." In response CEOMEIBCEIDE-1.39b (also part of Exhibit MEICEO-26) the
8 Company confirmed that this applies to Google's proposed facility.

9 **Q: What conclusions do you draw from this?**

10 A: DTE's decision to apply such load shed requirements to all large loads in its territory
11 indicates that it is aware of the reliability risks such facilities pose, and is taking steps to
12 address these risks. I support this decision and look forward to hearing DTE's response to
13 the recommendations I have made in testimony which are also critical to ensuring the
14 reliability of the Company's grid for all customers.

15 **V. RECOMMENDATIONS**

16 **Q: Please summarize your recommendations.**

17 A: To address the shortcomings of DTE's and Google's current plan to achieve
18 100% renewable annual matching, I recommend that the Company explore additional
19 means to add Google-funded renewables to its grid, such as increasing the portion of its
20 load served through the VGP program, pursuing VPPs and customer-sited resources, or
21 other solutions. Relatedly, I recommend that the Company provide additional detail, in
22 rebuttal, about the VGP Special Contract and associated transfer of RECs to clarify how
23 Google will achieve 100% annual matching.

1 Regarding the reliability impacts of the proposed facility, I provide the following
2 recommendations:

- 3 • I recommend that DTE provide, in rebuttal, the timeline for completing a
4 stability study.
- 5 • I recommend that in rebuttal, DTE provide the timeline for completing short
6 circuit and EMT studies, or a robust justification as to why they are not
7 needed in the instant case.
- 8 • I recommend that in rebuttal DTE provide the final version of the operating
9 parameters as an exhibit. If these parameters do not closely align with
10 MISO's proposed requirements, then the Company must provide detailed
11 justification for the parameters and how they address the reliability risks the
12 data center poses.

13
14 If the Company does not provide these details in rebuttal, then I recommend that
15 the Commission deny approval of the application until DTE is able to demonstrate that it
16 has or will sufficiently address these reliability risks.

17 **Q: Does this conclude your testimony?**

18 **A: Yes.**

1 MS. DUCKWORTH: Thank you, your Honor.

2 At this time, on behalf of MEICEO, I'd move to bind into
3 the record the Direct Testimony of Dr. Laura S. Sherman,
4 consisting of a cover page, a table of contents, and 47
5 pages of questions and answers. I also move for the
6 admission of Dr. Sherman's Testimony Exhibits MEICEO-32
7 through MEICEO-37.

8 JUDGE STALEY: All right. Are there any
9 objections to the binding in of the prefiled Direct
10 Testimony of Dr. Laura S. Sherman, or the admission of
11 Exhibits MEICEO-32 through 37?

12 Hearing none, the prefiled Direct
13 Testimony of Dr. Laura S. Sherman is bound into the
14 record, and Exhibits MEICEO-32 through 37 are admitted
15 into evidence.

16 (Direct Testimony bound in.)

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**STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION**

In the matter of the application of DTE ELECTRIC COMPANY for approval of special contracts and for other relief.	)))	Case No. U-22058

DIRECT TESTIMONY OF

DR. LAURA S. SHERMAN

ON BEHALF OF

**MICHIGAN ENERGY INNOVATION BUSINESS COUNCIL, INSTITUTE FOR
ENERGY INNOVATION, ECOLOGY CENTER, ENVIRONMENTAL LAW & POLICY
CENTER, UNION OF CONCERNED SCIENTISTS, AND VOTE SOLAR**

June 5, 2026

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1 **I. INTRODUCTION AND QUALIFICATIONS**

2 **Q: State your name, business name and address.**

3 A: My name is Dr. Laura S. Sherman, and I am the President of the Michigan Energy
4 Innovation Business Council (“Michigan EIBC”) and the Institute for Energy Innovation
5 (“IEI”), located at 115 West Allegan, Suite 710, Lansing, Michigan 48933.

6 **Q: On whose behalf are you appearing in this case?**

7 A: I am appearing here as an expert witness on behalf of Michigan EIBC and IEI, as well as
8 the Ecology Center, Environmental Law and Policy Center, Union of Concerned Scientists,
9 and Vote Solar, collectively referred to as the “Clean Energy Organizations” or “CEO.” I
10 will refer to these organizations collectively to as “MEI/CEO.”

11 **Q: Summarize your educational background.**

12 A: I have a Ph.D. from the University of Michigan Earth and Environmental Sciences
13 Department, conferred in May 2012. I also have a Bachelor of Science degree from
14 Stanford University in Geological and Environmental Sciences, conferred in June 2005.

15 **Q: Summarize your experience in the field of electric utility regulation.**

16 A: Since April 2019, I have served as the President of Michigan EIBC and IEI. Prior to that,
17 starting in February 2017, I was a Senior Consultant at 5 Lakes Energy focusing on energy
18 policy and utility regulation. I also served as the Vice President for Policy Development
19 for Michigan EIBC and IEI. In these capacities, I have written testimony in many non-
20 adjudicated dockets before the Michigan Public Service Commission (“Commission” or
21 “MPSC”). From 2014–2016, I served as a Policy Advisor on energy, environment, and
22 agriculture issues to Senator Michael Bennet (D-CO) in the U.S. Senate. In that capacity,
23 I provided policy expertise, conducted research, developed legislation, and analyzed

1 regulations. Prior to that, my doctoral (2007–2012) and postdoctoral (2012–2014) research
2 was focused on the tracing of pollutants emitted during energy generation. My work
3 experience is set forth in detail in my resumé, attached as Exhibit MEICEO-32.

4 **Q: Summarize your professional development coursework in the field of electric utility**
5 **regulation.**

6 A: In August 2017, I completed the Electric Utility Consultants Inc. (“EUCI”) course titled
7 “Optimizing the Interconnection Process for Renewables & Storage: A National Forum for
8 Addressing Process and Technical Issues.” In December 2017, I completed the EUCI
9 course titled “The Electric Vehicle-Utility Industry Nexus.” In January 2018, I completed
10 the EUCI course titled “Evolution of Electricity Markets: Disruptive Innovation &
11 Economic Impacts: Highly Interactive Course Designed to Provide A Practical Overview
12 of Evolving U.S. Power Markets.”

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

14 A: Yes. I previously testified as an expert witness in the following cases:

- 15 ● U-20134 (Consumers Energy Company [“Consumers Energy” or “Consumers”]
16 general electric rate case);
- 17 ● U-20165 (Consumers Energy Integrated Resource Plan [“IRP”] case);
- 18 ● U-20162 (DTE Electric Company [“DTE Electric” or the “Company”] general electric
19 rate case);
- 20 ● U-20471 (DTE Electric IRP case);
- 21 ● U-18232 (DTE Electric Renewable Energy Plan case);
- 22 ● U-20649 (Consumers Energy Voluntary Green Pricing [“VGP”] Program case);

- 1 ● Consolidated U-20713 (DTE Electric VGP Program case)/U-20851 (DTE Electric
- 2 Renewable Energy Plan case);
- 3 ● U-20693 (Consumers Energy general electric rate case);
- 4 ● U-21090 (Consumers Energy IRP case);
- 5 ● U-21131 (Consumers Energy Legally Enforceable Obligation case);
- 6 ● U-21134 (Consumers Energy VGP Program case);
- 7 ● U-20836 (DTE Electric general electric rate case);
- 8 ● U-21224 (Consumers Energy general electric rate case);
- 9 ● U-21172 (DTE Electric VGP Program case);
- 10 ● U-21193 (DTE Electric IRP case);
- 11 ● U-21297 (DTE Electric general electric rate case);
- 12 ● U-21374 (Consumers Energy VGP Program case);
- 13 ● U-21389 (Consumers Energy general electric rate case);
- 14 ● U-21534 (DTE Electric general electric rate case);
- 15 ● U-21482 (DTE Electric interconnection procedures case)
- 16 ● U-21375 (DTE Electric VGP Program case);
- 17 ● U-21860 (DTE Electric general electric rate case), and
- 18 ● U-21972 (Consumers Energy VGP Program case).

19 **Q: Have you provided analysis in support of testimony or comments in any other utility**
20 **regulatory proceedings?**

21 **A:** Yes, I have provided comments with input from Michigan EIBC member companies in a
22 number of different proceedings including:

- 23 ● U-18351 and U-18352 (development of voluntary green pricing programs);

- 1 ● U-20095 (Public Utility Regulatory Policies Act of 1978 [“PURPA”] regulations and
- 2 capacity determinations);
- 3 ● U-18383 (development of a distributed generation [“DG”] tariff);
- 4 ● U-18361 (code of conduct rules);
- 5 ● U-20147 (distribution system planning and utility distribution system plans);
- 6 ● U-20905 (implementation of Federal Energy Regulatory Commission [“FERC”] Order
- 7 872);
- 8 ● U-20890 (Interconnection and Distributed Generation Standards);
- 9 ● U-20898 (utility business models);
- 10 ● U-21099 (demand response aggregation);
- 11 ● U-21219 and U-18461 (IRP Filing Requirements and Planning Parameters);
- 12 ● U-20959 (customer data access);
- 13 ● U-21251 (grid system data access);
- 14 ● U-21400 (performance-based regulation/reliability metrics);
- 15 ● U-21547 (implementation of Public Act [“PA”] 233 regarding wind/solar/storage
- 16 siting);
- 17 ● U-21568 (implementation of PA 235 regarding the renewable portfolio standard);
- 18 ● U-21569 (implementation of PA 235 regarding the DG Program);
- 19 ● U-21567 (implementation of PA 299 regarding energy waste reduction and
- 20 electrification);
- 21 ● U-21571 (implementation of PA 235 regarding the energy storage mandate);
- 22 ● U-21653 (DTE Electric Expedited Pilot Review Workplan);
- 23 ● U-21492 (Transportation Electrification Plan guidelines);

- 1 • U-21570 (IRP Filing Requirements and Planning Parameters);
- 2 • U-21902 (Midcontinent Independent System Operator’s Expedited Resource Addition
- 3 Study tariff); and
- 4 • U-21637 (improvements to rate case processes).

5 In addition to this work, I have been involved on behalf of Michigan EIBC in
6 multiple workgroup proceedings at the Commission, including those focused on electric
7 vehicle (“EV”) deployment, DG tariffs, IRP requirements, energy waste reduction,
8 distribution system planning, interconnection standards and procedures, and renewable
9 energy siting procedures. I was involved on behalf of Michigan EIBC and IEI in the MI
10 Power Grid workshop proceedings at the Commission, including those focused on new
11 technologies and business models, customer data access, updating the state’s
12 interconnection rules, demand response, distribution system planning, pilot programs,
13 competitive procurement, advanced planning, and updating the IRP parameters and filing
14 requirements.

15 **Q: Please summarize your experiences working with advanced energy companies on**
16 **issues related to electric utility regulation.**

17 A: I have served as the President of Michigan EIBC and IEI since April 2019. Prior to that,
18 from November 2017 through April 2019, I served as Vice President of Policy
19 Development for Michigan EIBC and IEI. In these roles, I have led the trade organization’s
20 work on regulatory and legislative issues. As described above, I have participated in many
21 workgroups at the Commission and written comments in a number of non-adjudicated
22 cases. I also communicate formally and informally with Michigan EIBC member

1 companies about each regulatory proceeding to understand how the advanced energy
2 industry is affected by each proposed rule or case.

3 **Q: What is the purpose of your testimony?**

4 A: The purpose of my direct testimony is to describe, based on my experiences as the President
5 of Michigan EIBC and IEI, concerns regarding the ownership of renewable energy
6 resources and opportunities to utilize customer-sited and aggregated resources.

7 **Q: Are you sponsoring any exhibits?**

8 A: Yes, I am sponsoring the following exhibits:

- 9 • Exhibit MEICEO-32: Resumé of Dr. Laura S. Sherman
- 10 • Exhibit MEICEO-33: DTE response to CEOMEIBCIEIDE-1.6b
- 11 • Exhibit MEICEO-34: DTE response to CEOMEIBCIEIDE-1.33a
- 12 • Exhibit MEICEO-35: DTE response to CEOMEIBCIEIDE-1.1a
- 13 • Exhibit MEICEO-36: DTE response to CEOMEIBCIEIDE-1.8bi
- 14 • Exhibit MEICEO-37: DTE response to CEOMEIBCIEIDE-1.9c

15 **Q: Please summarize the Company's proposal in this case.**

16 A: As outlined in the direct testimony of witness Neal T. Foley, the Company seeks
17 Commission approval of two contracts to serve a new data center to be built by Google
18 LLC ("the Customer") in Van Buren Township, Michigan.¹ The Primary Supply
19 Agreement ("PSA") will govern the provision of electric service to the Customer and
20 provide ratepayer protections. The Clean Capacity Accelerator Agreement ("CCAA") will
21 govern the procurement of energy storage and renewable energy to serve the data center.
22 My testimony is focused on certain aspects of the CCAA.

¹ Direct Testimony of Neal T. Foley on behalf of DTE Electric Company ("Foley Direct"), Case No. U-22058.

1 **Q: What are the provisions of the CCAA?**

2 A: The CCAA

3 allows the Company to deploy a portfolio of up to 480 MW of energy
4 storage projects and up to 1,600 MW of renewable energy projects, and
5 recover from the Customer the full cost of these projects. . . . In addition,
6 the CCAA allows the Company to receive from the Customer 300 MW of
7 Midcontinent Independent System Operator (“MISO”) Zone 7 Zonal
8 Resource Credits (“ZRCs”) at no cost.²

9 More specifically, witness Foley states that the energy storage projects will include up to
10 425 MW of 4-hour lithium-ion batteries and up to 55 MW of at least 8-hour duration
11 storage³ and will be procured via a Request for Proposals (“RFP”) process. The ZRCs will
12 be provided by the Customer to the Company at no cost to the Company from June 1, 2028
13 through May 31, 2033.⁴ Separately from this agreement, the Customer will be subject to a
14 Rider 12 Demand Response (“DR”) Agreement, which commits the data center to a
15 reduction in demand to 650 MW when called upon between June 2027 and May 2033.⁵

16 **II. OWNERSHIP ISSUES**

17 **Q: Please summarize your concerns regarding ownership of the resources procured**
18 **under the CCAA.**

19 A: As described in detail below, in this case, I support the proposed split in ownership between
20 Company-owned and third-party owned projects for the energy storage resources procured
21 under the CCAA. However, the Company proposes that it will own all of the renewable
22 energy resources procured under the CCAA through a Special Contract with the Customer
23 (under the “Customer Requested Offering” or “CRO”). I oppose this ownership proposal

² Foley Direct at 4.

³ *Id.* at 25.

⁴ *Id.* at 23.

⁵ *Id.* at 6.

1 and instead recommend that the Company procure equivalent MWs of renewable energy
2 resources to fulfill demand for the CRO Special Contract, with 50% of the MWs from
3 third-party owned projects and 50% from Company-owned projects, including BTAs and
4 self-built projects.

5 **A. ENERGY STORAGE RESOURCES**

6 **Q: What is the proposed split in ownership for the energy storage projects?**

7 A: According to witness Foley, selected energy storage projects for the CCAA will be both
8 Company-owned and third-party owned, consistent with the ownership split agreed to in
9 the Company's last IRP case (Case No. U-21193).⁶ In that case, the parties agreed in
10 settlement that the Company would target 780 MW of storage by 2030, with 505 MW
11 being Company-owned and 275 MW being third-party owned.⁷ The parties also agreed
12 that

13 in any other solicitation any increase in capacity will be allocated
14 proportionately between Company owned and third party owned projects in
15 an amount similar to the combined build plan totals in Table 1 and 2 for
16 renewables and the overall total in Table 3 for storage provided that the
17 Company will have the discretion, but not the obligation, to acquire
18 additional capacity from third parties without proportionally increasing the
19 capacity allocated to Company-owned projects.⁸

20 The proportional allocation from Table 3 in the Company's IRP case is roughly 65%
21 Company-owned (including build-transfer agreements, "BTAs") and 35% third-party
22 owned. In a discovery request (Exhibit MEICEO-33), the Company confirmed that it plans
23 to follow this ownership split by procuring up to 480 MW of energy storage, with ~310
24 MW being Company-owned and ~170 MW being third-party owned.

⁶ *Id.* at 26.

⁷ Commission Order Approving Settlement Agreement, Case No. U-21193, July 26, 2023, paragraph 13 ("Case No. U-21193 Settlement Order").

⁸ *Id.* at ¶ 14.

1 **Q: Do you support the Company’s proposed ownership split for energy storage projects?**

2 A: In this case, yes. Throughout the Company’s last IRP case (Case No. U-21193), I argued
3 that the Company should procure roughly equal amounts of Company-owned and third-
4 party owned projects (*i.e.*, a 50/50 split).⁹ I continue to stand by those arguments and
5 positions. However, I understand that the Settlement Agreement in the Company’s last IRP
6 case (Case No. U-21193), which reflects a split with roughly 65% Company-ownership, is
7 applicable to this storage procurement. In keeping with the above quoted provision of the
8 Settlement Agreement,¹⁰ I encourage the Company to procure proportionally greater
9 capacity from third-party owned energy storage projects (above the required 35%),
10 especially to the extent that such projects are lower cost than comparable Company-owned
11 projects.

12 **B. RENEWABLE ENERGY RESOURCES**

13 **Q: What is the proposed split in ownership for the renewable energy projects?**

14 A: The Company proposes to own 100% of the renewable energy projects. The Company
15 proposes to procure these renewable energy resources through a Special Contract under the
16 CRO, which is part of its VGP Program. As described in more detail below, the CRO does
17 not have an established split in ownership—instead, by current program design, there is no
18 requirement that any of the resources procured under a CRO be owned by third-parties.

⁹ Direct Testimony of Dr. Laura S. Sherman on behalf of the Michigan Energy Innovation Business Council, Institute for Energy Innovation, Advanced Energy United, and Clean Grid Alliance, Case No. U-21193.

¹⁰ Case No. U-21193 Settlement Order at ¶ 14.

1 **Q: What are the origins of the CRO?**

2 A: The CRO was first approved by the Commission in its July 9, 2021 Order approving a
3 Settlement Agreement in DTE’s 2020 VGP case (Case Nos. U-20713/U-20851).¹¹
4 According to the Settlement Agreement, these individual contracts were for specific
5 customers and would be brought before the Commission on an *ex parte* basis.¹²

6 **Q: What was your original understanding of the types of projects that would be brought
7 as CRO projects?**

8 A: The Company’s testimony in DTE’s 2020 VGP case and the focus in the Settlement
9 Agreement in that case on a customer-requested project with the City of Ann Arbor
10 suggested that the vast majority of the customer-requested projects would be relatively
11 smaller projects with public institutions (*e.g.*, municipalities and higher education
12 institutions).

13 **Q: Has this been the case?**

14 A: No. To the contrary, the CRO projects that I am aware of are all multi-hundred MW
15 projects for corporate customers. One of these projects, a 650 MW Special Contract for
16 Ford Motor Company, was approved by the Commission on December 21, 2022.¹³ A
17 second CRO Special Contract between the Company and Stellantis Partners for 400 MW
18 of solar energy was approved on May 18, 2023.¹⁴

19 **Q: Why does this matter?**

20 A: As described below, because the CRO, as currently designed, has no established ownership

¹¹ Commission Order Approving a Settlement Agreement, July 9, 2021, Case Nos. U-20713/U-20851 (“Case Nos. U-20713/U-20851 Settlement Order”).

¹² *Id.*

¹³ Commission Order, December 21, 2022, Case No. U-21285.

¹⁴ Commission Order, May 18, 2023, Case No. U-21361.

1 split, all of these projects to date have been 100% owned by the Company. This has
2 significant implications for costs, maintenance of a competitive market, and risk to
3 ratepayers. These implications are more significant due to the size of the CRO projects that
4 have been developed so far and the projects proposed here.

5 **Q: How does the competitive bidding process work for CRO projects?**

6 A: According to the Settlement Agreement in DTE’s 2020 VGP case (Case Nos. U-20713/U-
7 20851) that established the CRO, “[the] details of the competitive process will be agreed
8 upon with the customer and will incorporate any competitive bidding rules specific to the
9 customer.”¹⁵ In other words, there is no established competitive bidding process for these
10 projects and instead, each process will be developed individually between the Company
11 and the customer seeking the Special Contract (*e.g.*, Ford, Stellantis, and Google).

12 **Q: What changes were made to the CRO because of the partial Settlement Agreement in**
13 **the Company’s 2022 VGP case (Case No. U-21172)?**

14 A: In the Company’s 2022 VGP case (Case No. U-21172), in part due to advocacy from
15 Michigan EIBC, IEL, and Advanced Energy United (“MEIU”), the Commission approved
16 a partial Settlement Agreement in which the Company agreed to procure a minimum of
17 50% of the capacity to serve each CRO Special Contract using BTAs with unaffiliated
18 third-parties.¹⁶ This agreement covered and included the previously approved Special
19 Contracts with Ford and Stellantis.¹⁷ The Company also agreed to a competitive bidding

¹⁵ Case Nos. U-20713/U-20851 Settlement Order at ¶ 9.1.2.

¹⁶ Commission Order Approving a Settlement Agreement, July 2, 2024, Case No. 21172, paragraph 1.

¹⁷ *Id.*

1 process including issuance of an RFP to identify BTA projects.¹⁸

2 Under a BTA, a project is developed and built by a third-party developer but is sold
3 to the utility prior to commercial operation. Although the utility does not self-develop and
4 build these projects, BTA projects are ultimately owned by the Company. In other words,
5 although the Settlement Agreement in the Company's 2022 VGP case (Case No. U-21172)
6 increased the ability for third parties to develop and build projects, projects procured under
7 the CRO remain 100% Company-owned.

8 **Q: Does the Company describe its plans to identify BTA projects to fulfill at least 50%**
9 **of the Customer's renewable energy needs under the CCAA?**

10 A: Not in direct testimony. However, in a discovery response (Exhibit MEICEO-34), the
11 Company clarified that

12 DTE Electric will issue an RFP as noted in Q31 for a minimum of 50% of
13 the capacity required to fulfill the VGP Special Contract through build
14 transfer agreements ("BTAs") with unaffiliated third parties consistent with
15 the Section 61 Settlement Agreement in Case No. U-21172.

16 **Q: Has the Company procured at least 50% BTA projects to fulfill the previously**
17 **approved CRO Special Contracts?**

18 A: No. The two CRO Special Contracts with Ford and Stellantis seek to procure a total of up
19 to 1,075 MW, meaning that roughly 540 MW are required to come from BTAs. However,
20 as of May 2026, the Company has not successfully procured any BTA projects to fulfill
21 these Special Contracts, but has received approval for nearly 500 MW of self-build
22 projects, outlined below:

- 23
- Ford Special Contract:

¹⁸ *Id.* at ¶ 2.

1 ○ Cold Creek Solar (100 MW solar project in Branch County, MI)¹⁹

2 ○ Deckerville Solar (200 MW solar project in Sanilac County, MI)²⁰

3 • Stellantis Special Contract:

4 ○ Silver Creek Solar Park (200 MW solar project in Huron County, MI)²¹

5 From the filings, it is unclear why no BTA projects have been procured to date. The

6 Company simply states in its application for approval of the self-built projects that

7 “currently, no projects have been contracted from the BTA RFP.”²²

8 **Q: How is procurement for renewable energy for the Company’s broader VGP program**
 9 **different from that for the CRO?**

10 **A: According to the partial Settlement Agreement in the Company’s 2022 VGP case (Case**
 11 **No. U-21172),**

12 Beginning with the Company’s 2024 renewable energy all-source RFP,
 13 capacity acquired to fulfill customer demand under the Company’s Rider
 14 17 Voluntary Green Pricing (“VGP”) Program will be subject to the
 15 ownership allocations set forth in paragraphs 12 and 14, collectively, of the
 16 July 26, 2023 Settlement Agreement approved in Case No. U-21193 (DTE
 17 Electric’s Integrated Resource Plan) (the “U-21193 Settlement
 18 Agreement”).²³

19 In other words, renewable energy procured to fulfill demand for the Company’s

20 VGP Program (Rider 17) *does* follow the same ownership split between Company-owned

21 and third-party owned projects as established in the Company’s last IRP case (Case No. U-

22 21193). As described above, this stands in stark contrast to renewable energy procured

23 under a CRO Special Contract.

¹⁹ Michigan Public Service Commission Order, Case No. U-21285, February 11, 2025.

²⁰ *Id.*

²¹ Michigan Public Service Commission Order, Case No. U-21361, March 13, 2025.

²² Michigan Public Service Commission Order, Case No. U-21285, February 11, 2025; Michigan Public Service Commission Order, Case No. U-21361, March 13, 2025.

²³ Commission Order Approving a Settlement Agreement, July 2, 2024, Case No. 21172, paragraph 6.

1 **Q: What is the ownership split for renewable energy resources agreed to in the**
2 **Company's last IRP case (Case No. U-21193)?**

3 A: The Settlement Agreement in the Company's last IRP case (Case No. U-21193) established
4 capacity allocations for renewables that are Company-owned (2,480 MW by 2030 or
5 ~65%) and third-party owned (1,320 MW by 2030 or ~35%).²⁴ The Settlement Agreement
6 also established that any additional resources would be procured in the same proportional
7 ownership allocations (*i.e.*, ~65% Company owned, 35% third-party owned), with the
8 Company allowed to procure additional third-party owned renewable projects.²⁵ As
9 described above, renewable energy projects procured under Rider 17 (the Company's VGP
10 program) are also now subject to this split in ownership.²⁶

11 **Q: Could the Customer in this case procure renewable resources through Rider 17**
12 **instead of through a CRO Special Contract?**

13 A: To my knowledge, yes. The Customer could procure 1.6 GW of renewable resources by
14 signing up for the Company's Rider 17 VGP Program. If the Customer were to do that, as
15 described above, the Company would be required to procure those resources according to
16 the ownership split established in the Company's last IRP case (Case No. U-21193; *i.e.*,
17 65% Company-owned, 35% third-party owned).

18 **Q: Are there reasons why the Company would prefer that a customer procure renewable**
19 **resources through a CRO Special Contract instead of via Rider 17?**

20 A: In my opinion, yes. If given the choice, a regulated utility, which earns a significant return
21 on equity for all capital expenditures, can be expected to prefer to invest its own capital to

²⁴ Commission Order Approving a Settlement Agreement, July 26, 2023, Case No. 21193, paragraph 12.

²⁵ *Id.* at ¶ 14.

²⁶ Commission Order Approving a Settlement Agreement, July 2, 2024, Case No. 21172, paragraph 6.

1 develop and own renewable energy projects to meet customer demand for renewable
2 energy. Given this capital bias, I would assume that the Company would prefer to procure
3 resources to meet a large load customer's renewable energy requirements through a CRO
4 Special Contract, where 100% of the resources are Company-owned (and up to 50% are
5 Company self-built), instead of through Rider 17 where ~35% of the resources must be
6 third-party owned.

7 **Q: Are there reasons that a customer might want the Company to procure third-party**
8 **owned resources to fulfill a CRO Special Contract?**

9 A: In my opinion, yes. Although it is true by statute that participants in the VGP program pay
10 the full costs of the program and receive any realized savings that are achieved,²⁷ those
11 customers likely want to secure the lowest cost projects that fit their established
12 requirements. As described further below, Company-owned projects may be more
13 expensive than third-party owned projects. Relatedly, a customer may want to support the
14 continued existence of a robust third-party market for renewable energy projects to ensure
15 continued access to low-cost projects in the future.

16 Furthermore, as described below, third-party owned resources may be capable of
17 reaching commercial operation more quickly than Company-owned resources, allowing
18 the Customer to achieve its clean energy objectives under the contract sooner. Under the
19 current procurement schedule associated with this Special Contract, the Company proposes
20 to procure 500 MW of renewable resources by 2030, 700 MW by 2031, and 400 MW by
21 2032. As a result, as proposed, more than half of the 1,600 MW of new renewable resources
22 would not come online until after 2030. Under current federal tax law and IRS guidance,

²⁷ MCL 460.1061.

1 wind and solar resources generally must either be placed in service by December 31, 2027
2 or begin construction on or before July 4, 2026 to preserve eligibility for the federal clean
3 electricity production tax credit under IRC § 45Y or the clean electricity investment tax
4 credit under IRC § 48E.²⁸ Third-party developers with existing project portfolios may have
5 already taken, or may be taking, steps before the July 4, 2026 deadline to safe harbor
6 projects through qualifying equipment procurement, transformer reservations, or other
7 begin-construction strategies. As a result, third-party developers may be able to offer
8 projects that have preserved tax-credit eligibility before a utility RFP is awarded and that
9 can remain eligible if placed in service by the end of 2030 within the applicable four-year
10 continuity safe harbor. Accordingly, it may be beneficial to the Customer, both in meeting
11 its clean energy objectives (as outlined in the testimony of MEI/CEO witness Lee Shaver)
12 and in lowering costs by increasing the likelihood that projects can qualify for and monetize
13 federal tax credits, to explore third-party owned renewable resources that could be procured
14 more quickly than resources owned by the Company under the current procurement plan.

15 **Q: How does the ownership of resources affect the procurement schedule?**

16 A: As described above, due to a partial Settlement Agreement in the Company's 2022 VGP
17 case (Case No. U-21172), the Company is required to procure a minimum of 50% of the
18 capacity to serve each CRO Special Contract using BTAs with unaffiliated third-parties,
19 with the remaining 50% of the capacity procured from self-built projects.²⁹ Given that the
20 Company does not currently consider third-party owned projects to fulfill CRO Special

²⁸ Internal Revenue Service, Beginning of Construction Requirements for Purposes of the Termination of Clean Electricity Production Credits and Clean Electricity Investment Credits for Applicable Wind and Solar Facilities, Notice 2025-42, August 15, 2025, available at <https://www.irs.gov/pub/irs-drop/n-25-42.pdf>, pp. 1, 4, 6.

²⁹ Commission Order Approving a Settlement Agreement, July 2, 2024, Case No. 21172, paragraph 1.

1 Contract demand, there may be a limited number of available self-built and BTA projects
2 available in the near-term. It is possible, therefore, that the Company's proposed
3 procurement schedule to fulfill the CRO Special Contract in this case is at least in part
4 driven by the limitations of the Company's existing self-built development pipeline and
5 the extended negotiation timelines typically associated with BTAs. Compared to PPAs
6 with third-party owned projects, BTAs can be more difficult to negotiate because these
7 agreements combine the components of both a PPA and an Engineering, Procurement, and
8 Construction ("EPC") contract. Additionally, because it is more difficult to obtain a change
9 order under a BTA, extended time negotiations may be needed to finalize the scope of the
10 project.³⁰ The additional complexity associated with a BTA structure is illustrated by
11 Consumers Energy's 2022 VGP RFP BTA Term Sheet, which requires due diligence,
12 negotiation of the BTA and related agreements, and review of project permits, real property
13 interests, interconnection rights, environmental reports, design documents, tax-credit
14 documentation, and other project records.³¹ These additional ownership-transfer
15 requirements can extend procurement and contracting timelines relative to arrangements
16 that do not involve a transfer of project ownership.

17 Since September 2025, the Company has received Commission approval for six
18 self-built solar projects totaling approximately 829 MW, all of which are expected to reach

³⁰ Morgan, Lewis & Bockius LLP, 2026 Energy Storage Policy & Market Roadmap, March 2026, Chapter 1, "Utility-Scale Energy Storage Procurements in 2026: Contracting and Risk Allocation," available at <https://www.morganlewis.com/-/media/files/publication/morgan-lewis-title/white-paper/2026/2026-energy-storage-policy-market-roadmap.pdf>, p. 9.

³¹ Consumers Energy Company, 2022 VGP RFP, Appendix D-3: Build Transfer Agreement (BTA) Term Sheet, available at <https://www.consumersenergy.com/-/media/CE/Documents/residential/renewable-energy/electric-power-notices/cecoco-2022-vgp-rfp-appendix-d3-build-transfer-agreement-bta-term-sheet.ashx?>, pp. 4–8.

1 commercial operation in 2028.³² Without additional information regarding the Company's
 2 broader development pipeline, it is reasonable to conclude that these projects represent a
 3 significant portion of the Company's late-stage development portfolio. This may help
 4 explain why the Company's proposed procurement timeline to fulfill demand for the CRO
 5 Special Contract in this case extends through 2032. Allowing PPAs as part of the
 6 procurement framework would increase the availability of resources with near-term
 7 commercial operation dates and may reduce the need to delay procurement into 2032.

8 **Q: Why is it beneficial in general for a utility to procure both third-party owned and**
 9 **company-owned assets?**

10 A: One essential role of the Commission is to determine whether utility proposals are
 11 "reasonable and prudent."³³ This includes ensuring that the lowest cost, highest quality
 12 projects are selected. Previous Commission reports have shown that since 2009:

13 for each year in which there were both company-owned projects and
 14 purchased power agreements, the weighted average cost of the purchased
 15 power agreements was lower than the company-owned projects in that
 16 respective year.³⁴

17 Then-Staff witness Meredith A. Hadala similarly noted in direct testimony in Case
 18

19 No. U-20984 that:

20 PPAs could provide VGP subscribers with a lower cost option for solar
 21 assets. For example, earlier this year, the Commission approved
 22 applications requesting approval of solar contracts resulting from the 2019
 23 [IRP] competitive solicitation. The average PPA and financial
 24 compensation mechanism (FCM) cost for the 25-year 140 MW Calhoun
 25 Solar Energy project is \$57.73/MWh. The company-owned BTA for the

³² Michigan Public Service Commission, "Renewable Energy," available at <https://www.michigan.gov/mpsc/consumer/electricity/renewable-energy>.

³³ Case No. U-22058, DTE Application for Approval of Special Contracts and for other relief, p. 6; *see also* MCL 460.6t.

³⁴ Michigan Public Service Commission, *Report on the Implementation and Cost Effectiveness of the PA 295 Renewable Energy Standard*, February 15, 2017, available at https://www.michigan.gov/-/media/Project/Websites/mpsc/regulatory/reports/pa295-ren/MPSC_PA295_Renewable_Energy_Report_Feb_2017.pdf?rev=3e166622d42a4a9fb4978343c7426d7c, p. 19.

1 150 MW Mustang Mile Solar project has a 25-year average cost of
 2 \$66.51/MWh. In this instance, the PPA with FCM is 13% less costly than
 3 the company-owned BTA. The Calhoun Solar Energy and Mustang Mile
 4 projects have expected commercial operation dates of 2022 and 2023,
 5 respectively. If the Company were to utilize PPAs, it could result in lower
 6 costs to VGP customers when compared to the Company's proposal to
 7 utilize only company-owned BTAs.³⁵

8 **Q: Have other jurisdictions similarly demonstrated that third-party renewable energy**
 9 **resources can be cost-competitive with utility-owned resources?**

10 A: Yes. In many cases, third-party owned renewable energy resources have been shown to be
 11 just as economic and, in many cases, more economic than utility-owned resources. To wit,
 12 I would highlight several examples from other vertically integrated, investor-owned
 13 utilities:

- 14 • In Virginia, Dominion Energy's 2024 IRP indicates that third-party owned solar
 15 is more economic than utility-owned solar assets on a \$/MWh basis.
 16 Specifically, Dominion assumes a cost of \$67/MWh for third-party owned solar
 17 resources, while utility-owned solar resources are estimated to result in a cost
 18 of \$80/MWh.³⁶
- 19 • In Washington and Idaho, Avista's 2025 IRP models all its projected solar,
 20 wind, and other renewable resource options as third-party owned rather than
 21 utility-owned resources.³⁷ These vertically integrated, investor-owned electric

³⁵ Direct Testimony of Meredith A. Hadala on behalf of the Michigan Public Service Commission, Case No. U-20984, at 6 (citing MPSC Case No. U-20165, Application dated February 12, 2021, Exhibit A-2 (footnote 1) and Exhibit A-3 (footnote 2) (footnotes omitted)).

³⁶ Dominion Energy Virginia, Appendix 3K-1 – Comparison of per MWh Costs of Selected Resources, 2024 Integrated Resource Plan, Case No. PUR-2024-00184, October 15, 2024, available at https://www.dominionenergy.com/-/media/content/about/our-company/irp/pdfs/2024-irp-w_o-appendices.pdf, pp. 257-258.

³⁷ Avista Utilities, 2025 Electric Integrated Resource Plan, December 31, 2024, available at <https://www.myavista.com/-/media/myavista/content-documents/about-us/our-company/irp-documents/2025/2025-avista-electric-irp.pdf>, pp. 185 and 191.

1 utilities have demonstrated that third-party owned renewable resources are a
2 viable and cost competitive option for procurement.

- 3 • In Colorado, the Public Service Company of Colorado, an operating subsidiary
4 of Xcel Energy Inc., targeted a 50/50 split of generation ownership in its 2025
5 Near-Term Procurement RFP. The RFP, which targeted 4,000 MW of
6 renewable energy and hybrid project capacity, had a stated goal to “[integrate]
7 maximal clean energy by securing as much cost-effective electric generation
8 under construction or placed in service as soon as possible.”³⁸

9 **Q: Do you expect these cost trends to continue into the future?**

10 A: Yes. By virtue of the nature of competition, I would expect that third-party owned
11 resources will continue to generally be less costly than Company-owned resources.
12 However, it is important to note that the playing field must be level and preferably, third-
13 party owned projects should be competing with other third-party owned projects to ensure
14 fair, strong competition. In addition to the elevated project costs inherent to an investor-
15 owned utility like DTE Electric with a current guaranteed return on equity of 9.90%,³⁹
16 competition among third-party developers to win contracts tends to drive down costs. In
17 the presence of this competition, it is simply less likely as an empirical matter that PPAs
18 with third-parties collectively would end up materially higher in price than Company-
19 owned projects.⁴⁰

³⁸ Public Service Commission of Colorado, an operating company subsidiary of Xcel Energy, Inc., PSCo 2025 Near-Term Procurement Request for Proposals, August 29, 2025, available at <https://xcelnew.my.salesforce.com/sfc/p/1U0000011ttV/a/R300000BqVCg/WvTerHpBFyd8qGYJphrfuLUmKI1EXD6R9N.8DeCgJ74>, p. 2.

³⁹ Commission Order in Case No. U-21860, February 19, 2026.

⁴⁰ As noted below, the revised, larger Financial Compensation Mechanism (“FCM”) may factor into this dynamic.

1 In the alternative, the lack of a robust competitive market for renewable projects in
2 Michigan would likely result in elevated costs. Simply put, if the utility is the only entity
3 practically able to build and own projects, there would be no reason to expect that costs
4 would remain low and every reason to expect costs would be higher.

5 **Q: Are there other reasons that a customer may want to procure third-party owned**
6 **resources?**

7 A: Yes. Beyond these historic price differences, fostering a competitive market will help
8 ensure that future prices remain competitive for customers. A strong third-party market
9 will provide competitive prices for the simple reason that cost is a very important, if not
10 the most important, factor in determining the winning bid(s) in an RFP. As such,
11 competitors are only awarded contracts if their projects are the least-cost, best-fit bids—
12 thereby helping to ensure that customers and ratepayers are paying the lowest prices.
13 Customers will likely pay the lowest prices *only* if there is actual competition among
14 projects bid into solicitations from many competitors in a well-developed market and not
15 simply a veneer of competition within a system that is otherwise skewed toward utility
16 ownership and utility-owned projects winning bids. Without a path to ownership, third-
17 party developers, many of whom operate on an Independent Power Producer (“IPP”) model
18 of ownership and operation of assets, may limit development in Michigan over time,
19 instead preferring neighboring states that offer better market opportunities.

20 Opportunities for third-party ownership and third-party competition reduce the risk
21 that customers and ratepayers will pay elevated monopoly prices that benefit utilities and
22 their shareholders rather than customers and ratepayers. In other words, without a strong
23 third-party competitive market, the utility will not face competition, which would likely

1 result in price increases over time. Although the Commission has the authority to disallow
2 costs to ratepayers should it deem them unreasonably high, without a competitive market
3 to provide a touchpoint for what market prices *should* be at any given time, the Commission
4 would be starved of the information necessary to indicate when and in which cases such
5 disallowances should be made. Given the demonstrated capital bias of monopoly utilities,⁴¹
6 it behooves the Commission to heed, consider, and when appropriate, take action to
7 mitigate these risks.

8 In addition, there are also important risk-allocation considerations associated with
9 third-party owned projects. In Virginia, State Corporation Commission (“SCC”) Staff has
10 found that third-party solar PPAs can be the “least cost, lowest risk option,” explaining
11 that, where “all operational risk is borne by the solar developer,” the utility’s ratepayers
12 and shareholders are shielded from that risk.⁴² In contrast, SCC Staff found that Company-
13 build, rate-based solar was the “highest cost, highest risk option” and that such projects
14 expose jurisdictional customers to operational and performance risk, even where a
15 performance guarantee shields customers from some, but not all, of that risk.⁴³ Maintaining
16 a balanced mix of Company-owned and third-party owned resources therefore provides
17 important risk diversification benefits. It allows the utility to distribute risk across multiple
18 counterparties while also benefiting from the experience, existing development pipelines,
19 and execution capabilities of third-party developers, which, as described above, may enable
20 projects to come online more quickly and efficiently than utility self-built alternatives. For

⁴¹ See Rosenbach, *et al.*, Rocky Mountain Institute, “The Nuts and Bolts of Performance-Based Regulation: Tools to Build a More Affordable, Reliable, and Equitable Grid,” July 2024, available at https://rmi.org/wp-content/uploads/dlm_uploads/2024/07/PBR_Deck_final.pdf, p. 11.

⁴² Virginia State Corporation Commission Staff, Pre-Filed Testimony of Gregory L. Abbott, Virginia Electric and Power Company, Case No. PUR-2019-00105, November 19, 2019, available at <https://www.scc.virginia.gov/docketsearch/DOCS/4jxv01%21.PDF>, pp. 1, 6–7.

⁴³ *Id.*

1 the reasons I describe below, this risk reduction is important even where the resources are
2 to be funded by a specific customer.

3 **Q: Are there other reasons that the Commission should require the Company to procure**
4 **third-party owned resources to fulfill this CRO Special Contract?**

5 A: Yes. According to the partial Settlement Agreement in the Company's 2022 VGP case
6 (Case No. U-21172),

7 In the event a Special Contract is terminated by the customer, for cost
8 recovery purposes, the Company will allocate the contract capacity first to
9 the VGP Program, and, if the contract capacity exceeds what is needed to
10 meet current VGP Program demand, the Company will allocate the contract
11 capacity to its Renewable Energy Plan or Clean Energy Plan, in each case
12 approved under Public Act 342 of 2016, as amended by Public Act 235 of
13 2023, MCL 460.1001 *et seq.* (the "Clean Energy Law"). If the contract
14 capacity is not needed to fulfill VGP Program demand or to comply with
15 the Company's obligations under the Clean Energy Law, and termination
16 penalties are insufficient, the Company will notify Staff of the actions being
17 taken to mitigate impacts on customers.⁴⁴

18 Given this agreement, if the Customer terminates the CRO Special Contract,
19 those resources would be first allocated to other customers in the VGP Program. If there is
20 not sufficient demand for the resources by other customers in the VGP Program, the
21 resources would be allocated to all ratepayers through the Renewable Energy Plan or Clean
22 Energy Plan. Given the potential future risk to ratepayers, it behooves the Commission to
23 not simply accept any and all Company-owned resources agreed to by the Customer and
24 the Company to fulfill the CRO Special Contract and instead to insist upon greater
25 competition through the retention of and access to a strong third-party market.

⁴⁴ Commission Order Approving a Settlement Agreement, July 2, 2024, Case No. 21172, paragraph 7.

1 **Q: What role does a customer have in establishing the process of selecting resources**
2 **through a CRO Special Contract?**

3 A: As described above, according to the Settlement Agreement in the Company's 2020 VGP
4 case (Case No. U-20713/U-20851) wherein the CRO was established,

5 The details of the competitive process will be agreed upon with the
6 customer and will incorporate any competitive bidding rules specific to the
7 customer.⁴⁵

8 In other words, as long as the process also aligns with the partial Settlement
9 Agreement in Case No. U-21172, a customer procuring resources through a CRO Special
10 Contract should play a significant role in establishing the competitive bidding process for
11 the resources and asserting any specific requirements.

12 **Q: What do you recommend with respect to ownership of resources procured for the**
13 **CRO Special Contract?**

14 A: I recommend that the Commission require the Company to procure equivalent MWs of
15 renewable energy resources to fulfill demand for the CRO Special Contract, with 50% of
16 the MWs from third-party owned projects and 50% from Company-owned projects,
17 including BTAs and self-built projects.

18 **III. CUSTOMER-SITED RESOURCES**

19 **Q: Please describe in more detail the ZRC component of the CCAA.**

⁴⁵ Case Nos. U-20713/U-20851 Settlement Order at ¶ 9.1.2.

1 A: The CCAA requires the Customer to obtain and transfer, at no cost to the Company, 300
2 MW of ZRCs⁴⁶ from June 1, 2028 until May 31, 2033.⁴⁷ Importantly, because there is no
3 cost to the Company, there is also no cost to ratepayers for these ZRCs.

4 According to MISO, ZRCs

5 are the fungible unit by which the Planning Resource Auction (“PRA”) is
6 conducted and means by which MISO members demonstrate they have
7 sufficient capacity to meet Resource Adequacy requirements. A ZRC
8 represents one (1) megawatt of deliverable Seasonal Accredited Capacity
9 (“SAC”).⁴⁸

10 Load Serving Entities (“LSE”), like the Company, must comply with MISO resource
11 adequacy requirements, namely through the Planning Reserve Margin Requirements
12 (“PRMR”). According to Company witness Justin J. W. Brooks, the 300 ZRCs are
13 necessary to meet the Company’s increased PRMR resulting from the proposed data center.
14 These ZRCs, in addition to the renewable energy, energy storage, and demand response
15 resources will “[ensure] that the Company will have sufficient capacity to meet MISO’s
16 resource adequacy requirements.”⁴⁹

17 **Q: Does the Company provide any more details on what capacity resources the Customer**
18 **plans to procure to provide the 300 ZRCs?**

19 A: No, the Company does not provide further detail regarding what resources the Customer
20 plans to procure to provide the 300 ZRCs. In a discovery response (Exhibit MEICEO-35),
21 the Company further stated that

⁴⁶ Of note, it is unclear whether the Company means that the Customer will obtain 300 MW of capacity and transfer the corresponding ZRCs or whether the Customer will obtain sufficient MW of capacity to transfer 300 ZRCs. For the purposes of this testimony, I will assume the later and will hereafter refer to this amount as “300 ZRCs.”

⁴⁷ Foley Direct at 23.

⁴⁸ MISO Help Center, “How to Convert Seasonal Accredited Capacity (SAC) associated with Energy Resource Service (ERIS) into Zonal Resource Credits (ZRC),” April 24, 2026, available at <https://help.misoenergy.org/knowledgebase/article/KA-01402/en-us>.

⁴⁹ Direct Testimony of Justin J. W. Brooks on behalf of DTE Electric Company, Case No. U-22058, p. 5.

1 The ‘ZRC Product’ is defined in the CCAA as ‘MISO Zone 7 Zonal
2 Resource Credits in an amount equal to 300MW’ (page A-12). The
3 Company cannot place additional restrictions on the ZRCs beyond this
4 definition. The Company is not involved in the Customer’s procurement of
5 the ZRCs that it will transfer to the Company and notes that the ZRCs are
6 being transferred to the Company at no cost.

7 In other words, the Company is not placing any requirements on the Customer regarding
8 the types of resources that are procured to provide the needed ZRCs.

9 **Q: Are there different ways in which the 300 ZRCs could be met?**

10 A: Yes, there are multiple capacity resources (or combinations of capacity resources) that the
11 Customer could procure to provide the 300 ZRCs. The 2025/2026 MISO PRA results
12 indicate that a variety of resource types made up the cleared ZRCs, including solar, wind,
13 battery energy storage, demand response, behind-the-meter generation, and energy
14 efficiency.⁵⁰

15 **A. DEMAND RESPONSE**

16 **Q: Does the Company register residential DR assets in MISO’s annual PRA?**

17 A: Yes. The Company registers its DR portfolio, including residential DR assets, as load
18 modifying resources (“LMRs”) with MISO.^{51, 52}

19 **Q: What is the Smart Savers program?**

20 A: Residential and small commercial business ratepayers with an eligible programmable
21 controllable thermostat (“PCT” *i.e.*, smart thermostat) can enroll in the Smart Savers
22 program. Under this program, the ratepayer allows the Company to adjust the setpoint
23 temperature of their thermostat up to four degrees during events.⁵³ Events are called

⁵⁰ MISO, “Planning Resource Auction: Results for Planning Year 2025-26,” Reposted May 29, 2025, available at https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf.

⁵¹ Direct Testimony of Keegan O. Farrell on behalf of DTE Electric Company, Case No. U-21919, p. 6.

⁵² Direct Testimony of Marcus B. Leuker on behalf of DTE Electric Company, Case No. U-22046, p. 44.

⁵³ *Id.* at 56.

1 between 12:00pm and 8:00pm on weekdays during the summer season, can last no more
 2 than four hours, and are limited to 56 total hours annually.⁵⁴ Customers receive a \$50 bill
 3 credit annually for their participation.⁵⁵

4 According to witness Marcus B. Leuker in the current DTE Electric rate case
 5 (Case No. U-22046),

6 As of December 31, 2025, there were 95,531 thermostats enrolled in the
 7 program. The Company anticipates enrolling an additional 40,000
 8 thermostats through the end of the projected test period for a total of
 9 125,531 thermostats enrolled in the program, providing nearly 94 MWs of
 10 demand response capacity by the 2028/29 Planning Year.⁵⁶

11 **Q: How could the Smart Savers program be leveraged to provide some of the needed 300**
 12 **ZRCs?**

13 A: There is still significant room for growth of both enrollment of existing PCTs and
 14 deployment of new PCTs in the Company's Smart Savers program. According to the 2025
 15 Michigan Energy Waste Reduction, Demand Response, and Efficient Electrification
 16 Statewide Potential Study:

17 if desired, there is still room for significant growth – smart thermostats
 18 continue to gain market adoption both naturally and from utility programs,
 19 and survey results indicate that only about 50% of respondents are aware
 20 that the programs exist.⁵⁷
 21

22 Given this, the Smart Savers program could be leveraged in multiple ways. With
 23 funding from the Customer, the program could be expanded to enroll additional customers

⁵⁴ *Id.* at 56-57.

⁵⁵ DTE Energy, "Smart Savers," available at <https://solutions.dteenergy.com/dte/en/Products/Smart-Savers/p/SMARTSAVERS>.

⁵⁶ Direct Testimony of Marcus B. Leuker on behalf of DTE Electric Company, Case No. U-22046, p. 57.

⁵⁷ NV5 and Slipstream, "2025 Energy Waste Reduction, Demand Response, and Efficient Electrification Statewide Potential Study," October 17, 2025, available at https://www.michigan.gov/mpsc/-/media/Project/Websites/mpsc/workgroups/ewr-study/Volume-III-Demand-Response-Statewide-Potential-Study_20251017.pdf?rev=3ba4b67bd07c4ce48026292db047e65e&hash=48D472A96D7B5C16C5D5D52B6ADBE616.

1 and provide the Company with some of the needed ZRCs. This could involve expanded
2 enrollment of ratepayers with existing PCTs wherein the annual bill credits for these
3 ratepayers are paid for by the Customer and where the expanded enrollment efforts are paid
4 for by the Customer. According to the Company, its third-party implementation contractor,
5 EnergyHub, currently facilitates enrollment marketing by partnering with thermostat
6 vendors to send in-app notifications to customers with eligible PCTs.⁵⁸ There may be
7 opportunities to enhance these activities with additional funding provided by the Customer.

8 **Q: Are there other ways in which existing PCT customers could be enrolled in the Smart**
9 **Savers program?**

10 A: Yes. The Smart Savers program could authorize an additional enrollment pathway under
11 which original equipment manufacturer (“OEMs”) of smart thermostats—or a
12 manufacturer-designated operator—enroll and dispatch participating devices in the
13 Company’s service territory on the Company’s behalf. In other words, an OEM could bring
14 its existing PCT customers to the Smart Savers program and, when dispatched by the
15 Company (via its third-party implementation contractor, EnergyHub), the OEM would
16 control each ratepayer’s PCT. This enrollment pathway has the possibility to leverage a
17 significant number of existing PCTs through their OEMs—simplifying enrollment and
18 saving the Company and the ratepayer significant administrative burden. As above, any
19 additional costs to enroll and credit these new Smart Savers enrollees would be paid for by
20 the Customer.

21 This pathway is particularly relevant in this case because the Customer has direct
22 relationships with a substantial installed base of smart thermostats in the Company’s

⁵⁸ DTE Electric Company, “2023 Annual Demand Response Report,” June 28, 2024, Case No. U-20628.

1 service territory through prior retail sales and prior enrollment in manufacturer-operated
2 programs. Many of these devices, and others, are not currently enrolled in Smart Savers
3 but are technically capable of providing demand flexibility today and could be enrolled
4 quickly through OEM relationships without requiring new device installations or new in-
5 home customer interactions. If this option is adopted, it is important that these customers
6 are not required to re-enroll in Smart Savers, but are deemed enrolled through their OEM
7 program, provided that the customer's existing terms of service with the OEM authorize
8 the OEM to dispatch load-shifting events for grid reliability purposes and the OEM certifies
9 enrollment to the Company. Requiring these customers to re-execute a separate Company
10 enrollment agreement would impose a significant cost and administrative burden that is
11 not necessary to document customer consent, since consent has already been captured by
12 the OEM.

13 **Q: How would load reductions from this option provide capacity benefits to the**
14 **Company?**

15 A: There are two ways through which OEM-led enrollment could provide capacity benefits.
16 PCTs enrolled in the Smart Savers program through an OEM could be registered with
17 MISO along with the rest of the DR portfolio. If registered, the resource would produce
18 ZRCs that flow to the Company in the same manner as other ZRCs under the CCAA.

19 PCTs enrolled through an OEM could also be used to reduce the Company's peak
20 demand. MISO resource adequacy obligations are driven by each LSE's PRMR, which is
21 calculated based on the LSE's contribution to MISO coincident peak. Verified load
22 reductions delivered during the MISO coincident peak hour reduce the Company's
23 contribution to system peak and therefore reduce the Company's PRMR—regardless of

1 whether the underlying resource is separately registered with MISO. The net capacity
2 benefit to the Company is equivalent.

3 The reason both pathways should be available is practical: OEM-led demand
4 flexibility programs do not always involve the sharing of utility account numbers between
5 the OEM operator and the participating customer, because the customer's primary
6 relationship is with the device manufacturer rather than the utility. MISO registration of
7 DR resources currently requires utility account-level identification of participating
8 customers, which can be a barrier to registering OEM-led resources directly.⁵⁹ Registration
9 practices may evolve over time, but the capacity benefit to the Company should not be
10 made contingent on the resolution of those practices. What matters for the purposes of the
11 CCAA is that the Company's capacity position is improved by the amount specified—not
12 the specific MISO accounting mechanism.

13 **Q: Are there additional ways in which the Customer could support enrollment of**
14 **additional PCTs in the Smart Savers program?**

15 A: Yes. The Customer could subsidize the costs to residential ratepayers for a new PCT to
16 enable the enrollment of additional, new customers in the Smart Savers program. Any
17 ratepayer receiving a subsidized PCT through this opportunity should be required to enroll
18 in the Smart Savers program. These subsidies could be scaled with income such that the
19 Customer pays for the full cost of new PCTs for eligible low and moderate-income
20 customers ("LMI," herein defined as those ratepayers at or below 400 percent of the federal

⁵⁹ MISO, "Business Practice Manuals: BPM 011- Resource Adequacy," available at <https://www.misoenergy.org/legal/rules-manuals-and-agreements/business-practice-manuals/>, Section 4.2.7.3.

1 poverty level⁶⁰) and for a portion of the cost of new PCTs for non-eligible higher income
2 customers. This would enable the enrollment of customers who would otherwise not
3 participate in the Smart Savers program, again providing ZRCs to the Company funded by
4 the Customer. Importantly, as emphasized previously, none of these costs would be borne
5 by the Company or ratepayers, but would be borne by the Customer.

6 **Q: What additional benefits would these proposals provide?**

7 A: In addition to the provision of no-cost ZRCs to the Company and the (likely) lower-cost of
8 ZRCs to the Customer, providing PCTs to residential ratepayers would benefit ratepayers
9 by enabling them to better control their energy usage, ultimately reducing their monthly
10 energy bills. According to the U.S. Department of Energy (“DOE”), an ENERGY STAR
11 smart thermostat saves a customer approximately 8% of heating and cooling costs or
12 approximately \$50 per year.⁶¹ These savings are especially beneficial to LMI customers
13 who often have a higher energy burden.⁶² A 2024 study from the American Council for an
14 Energy-Efficient Economy (“ACEEE”) found that low-income renters in Detroit spend an
15 average of 16.4% of their income on energy, and that half of all low-income Detroit
16 households spend more than 9% of their income on energy costs.⁶³

⁶⁰ In DTE Electric’s current general electric rate case filing (Case No. U-22046), with respect to proposed modifications to transportation electrification rebates, the Company defines “low-income” as households at or below 200% of the federal poverty level and “middle-income” as households between 201% and 400% of the federal poverty level. *See* Direct Testimony of Milena Kabashi on behalf of DTE Electric Company, Case No. U-22046, pp. 34-35.

⁶¹ U.S. Department of Energy, “ENERGY STAR Smart Thermostats FAQs for EEPS,” available at https://www.energystar.gov/products/heating_cooling/smart_thermostats/smart_thermostat_faq.

⁶² “Energy burden” is defined by the DOE as “the percentage of gross household income spent on energy costs.” *See* “Low-Income Energy Affordability (LEAD) Tool,” available at <https://www.energy.gov/cmei/scep/low-income-energy-affordability-data-lead-tool>.

⁶³ Davidson, K. “Detroit households face high energy costs, study says,” September 16, 2024, available at <https://michiganadvance.com/2024/09/16/detroit-households-face-high-energy-costs-study-says/>.

1 **B. VIRTUAL POWER PLANT PROGRAM**

2 **Q: What additional steps should be taken to procure more of the needed 300 ZRCs?**

3 A: As detailed further below, I recommend that the Company leverage existing and new
4 customer-owned battery energy storage plus solar systems to provide some portion of the
5 needed 300 ZRCs through a virtual power plant (“VPP”) program. This VPP program
6 should be established with stakeholder input within nine months of the Commission’s final
7 order in this case including program tariffs, aggregator contracts, enrollment channels, and
8 measurement and verification protocols. As described below, given that the 300 ZRCs are
9 not needed until 2028, enrollment in the VPP could be done in a stepwise manner
10 incorporating existing behind-the-meter battery energy storage plus solar systems, new
11 behind-the-meter battery energy storage plus solar systems, and eventually other
12 distributed energy resources (“DERs”). Ultimately, this VPP program could provide
13 important learnings and information to enable a broader program—with the initial program
14 coming at no cost to ratepayers or the Company.⁶⁴

15 **Q: What is a VPP?**

16 A: A VPP is an aggregation of DERs, such as smart thermostats and water heaters, residential
17 batteries paired with rooftop solar, EV managed charging, and flexible loads coordinated
18 to balance supply and demand and deliver utility-grade grid services. According to the
19 DOE, as of early 2025, there was roughly 30 GW of VPP capacity deployed across the

⁶⁴ Although broader cost allocation issues associated with the CCAA and PSA are discussed by MEI/CEO witness William Kenworthy, I will note that this proposal for a Customer-funded VPP program is aligned with the White House Ratepayer Protection Pledge signed by Google and other companies in March 2026. *See* White House, “Fact Sheet: President Trump Announces Ratepayer Protection Pledge for Data Center Energy,” March 2026, available at <https://www.whitehouse.gov/fact-sheets/2026/03/fact-sheet-president-donald-j-trump-advances-energy-affordability-with-the-ratepayer-protection-pledge/>.

country, with VPP potential expected to reach up to 160 GW by 2030.⁶⁵ There are different types of VPPs with different levels of complexity, from traditional DR programs to grid-adaptive VPPs.⁶⁶

Q: How do VPPs compare to traditional, centralized generation?

A: One difference is speed to power, which is critical for hyperscale data centers such as that proposed in this case wherein the Customer's load is planned to begin coming online in December 2027 and ramp up to its maximum load by December 2028.⁶⁷ VPPs can be deployed to meet data center demand on these rapid timelines. For example, National Grid's ConnectedSolutions VPP program launched in under four months and now has 250 MW of peak shaving capacity in Massachusetts and New York.⁶⁸ On the other hand, traditional, centralized generation takes anywhere from four to six years to build due to lengthy transmission interconnection queues⁶⁹ and supply chain issues (e.g., for gas turbines⁷⁰).

Another difference is cost. According to the DOE, using an example 400 MW resource, VPPs are approximately half the cost of a natural gas peaking plant on a per kW basis.⁷¹ Furthermore, according to a study by RMI, a portfolio of resources that includes

⁶⁵ U.S. Department of Energy, "Pathways to Commercial Liftoff: Virtual Power Plants 2025 Update," January 2025, available at https://www.smartenergydecisions.com/wp-content/uploads/2025/04/liftoff_doe_virtualpowerplants2025update.pdf, p. 3.

⁶⁶ EnergyHub, "Building trustworthy virtual power plants: The VPP Maturity Model," 2026, available at <https://www.energyhub.com/resource/building-trustworthy-power-plants-vpp-maturity-model>.

⁶⁷ Foley Direct at 9.

⁶⁸ U.S. Department of Energy, "Pathways to Commercial Liftoff: Virtual Power Plants 2025 Update," January 2025, available at https://www.smartenergydecisions.com/wp-content/uploads/2025/04/liftoff_doe_virtualpowerplants2025update.pdf, p. 31.

⁶⁹ *Id.* at 11.

⁷⁰ Utility Dive, "5-year waits and rising costs: How demand is redefining the gas turbine market," March 23, 2026, available at <https://www.utilitydive.com/news/5-year-waits-and-rising-costs-how-demand-is-redefining-the-gas-turbine-mar/813385/>.

⁷¹ U.S. Department of Energy, "Pathways to Commercial Liftoff: Virtual Power Plants 2025 Update," January 2025, available at https://www.smartenergydecisions.com/wp-content/uploads/2025/04/liftoff_doe_virtualpowerplants2025update.pdf, p. 13.

VPPs compared to a baseline portfolio without VPPs reduces net generation costs by 20% annually.⁷²

Q: Has the Commission provided guidance in recent cases on VPPs?

A: Yes, in two recent cases the Commission has provided guidance on VPPs. In Consumers Energy’s most recent rate case (Case No. U-21870), multiple parties, including MEIU⁷³ and CEO⁷⁴ commented on the benefits of VPPs and why the Company should consider utilizing them. In its final order, quoting from MEIU’s exceptions to the Proposal for Decision, the Commission issued

...a prospective warning to the Company that, in light of the ‘extensive support for VPPs’ in the record and the fact that ‘VPPs can provide a multitude of grid benefits, increase system reliability, and avoid or defer costly capital investments,’ future proposed investments that fail to account for VPPs may be disallowed.⁷⁵

Separately, in the open docket establishing new Integrated Resource Planning Parameters and Filing Requirements (Case No. U-21867), CEO argued that the Commission should require “...utilities to model aggregated DERs as selectable capacity resources within the optimization process.”⁷⁶ Subsequently, the Commission in its final order required each utility to “consider and model aggregated DG, distributed energy resources (DER) and virtual power plants (VPP) as selectable resources in its IRP.”⁷⁷

⁷² Becker, J., *et al.*, RMI, “Power Shift: How Virtual Power Plants Unlock Cleaner, More Affordable Electricity Systems,” September 2024, available at https://rmi.org/wp-content/uploads/dlm_uploads/2024/09/power_shift_report.pdf.

⁷³ Initial Brief of Michigan Energy Innovation Business Council, Institute for Energy Innovation, and Advanced Energy United, December 5, 2025, Case No. U-21870, pp. 32-34.

⁷⁴ Direct Testimony of William D. Kenworthy on behalf of The Ecology Center, The Environmental Law & Policy Center, Union of Concerned Scientists, and Vote Solar, Case No. U-21870.

⁷⁵ Commission Order in Case No. U-21870, March 27, 2026, p. 493.

⁷⁶ Comments from the Clean Energy Organizations on the Final Draft Michigan Integrated Resource Planning Parameters and Filing Requirements, October 31, 2025, p. 8.

⁷⁷ Commission Order in Case No. U-21867, December 18, 2025, p. 36.

1 **Q: Are there existing resources in the Company’s territory that could participate in a**
2 **VPP?**

3 A: Yes. In addition to DR resources such as the PCTs in the Smart Savers program described
4 above, 2,957 customers reported owning 36.386 MWh of behind-the-meter battery energy
5 storage deployed in association with rooftop solar systems in the Company’s territory as
6 of March 31, 2026.⁷⁸ Assuming most (if not all) of these are 4-hour batteries, this represents
7 approximately 9.1 MW of capacity. These existing, installed storage systems could be
8 relatively quickly enrolled in a VPP which builds upon the Company’s existing, successful
9 DR programs. These batteries could then be used initially for peak load reduction while
10 preserving the ability for the ratepayer to utilize the battery for backup power.

11 Similar programs in other states have been able to enroll participants quickly and
12 scale rapidly. For example, Rocky Mountain Power’s Wattsmart program was able to
13 enroll 6,000 residential batteries between its approval in late 2020 and May 2025.⁷⁹

14 **Q: How would ratepayers be compensated for enrolling their existing behind-the-meter**
15 **battery energy storage systems in such a VPP?**

16 A: Initially, customers with existing battery energy storage plus solar systems could be
17 provided with a limited enrollment incentive to encourage participation, in a similar
18 manner to the rebate for existing customers with PCTs to participate in the Smart Savers
19 program, but scaled to reflect the higher cost of these systems and the additional benefits
20 that these systems can provide. This enrollment incentive could be scaled on a per kW basis
21 and would be funded by the Customer.

⁷⁸ DTE Electric Company’s 2025 Annual Interconnection Report, Case No. U-20890, March 31, 2026.

⁷⁹ Demand Side Management 2024 Annual Energy Efficiency and Peak Load Reduction Report, Rocky Mountain Power, Docket No. 25-035-36, May 27, 2025.

Performance incentives for ongoing participation should also be included and should reflect the value that the DERs provide. At the outset, this value would likely be calculated as the capacity value of the ZRCs produced by these assets. However, as described below, as this program evolves and additional value streams are identified and quantified, a portion of that additional value should also be transferred to the system owners (*i.e.*, ratepayers) in the calculation of the performance incentives. These pay-for-performance incentives should be established for the duration of the ratepayer's commitment period to the program and may require adherence to performance baselines to ensure participation during events.

Q: How would new behind-the-meter battery energy storage systems be enrolled?

A: Subsequent ratepayers without existing battery energy storage plus solar systems or ratepayers with a solar system but without a battery energy storage system should be offered a larger upfront incentive provided by the Customer to enable the ratepayers to purchase the system and participate in the VPP. This process should include a pathway to enable third-party aggregators (including entities that finance, install, own, and operate customer-sited battery energy storage plus solar systems⁸⁰) to enroll and dispatch customers. Multiple considerations should be taken into account when structuring this upfront incentive including size of the device, income of the ratepayer, and calculated benefits to Customer (and thereby to the Company). Most importantly, for LMI ratepayers, the Customer should pay for the full cost of the battery energy storage plus solar system.

⁸⁰ These aggregations may be especially valuable to provide dispatch reliability by reducing homeowner opt-out and enrollment attrition. As MISO institutes its forthcoming Direct Loss of Load ("DLOL") accreditation methodology, guaranteed dispatch will become increasingly valuable. See U.S. Department of Energy, "Pathways to Commercial Liftoff: Virtual Power Plants 2025 Update," January 2025, available at https://www.smartenergydecisions.com/wp-content/uploads/2025/04/liftoff_doe_virtualpowerplants2025update.pdf, pp. 6-8, 14-17.

1 In the future, as described below, if the VPP program expands to provide
2 distribution system benefits (and expands beyond the contract between the Company and
3 the Customer), this upfront incentive could be increased in areas where grid capacity is
4 constrained and avoiding upgrades is more beneficial. For example, Green Mountain
5 Power offers an extra \$100 per kW on top of the existing \$950 per kW upfront incentive
6 for customers in grid-constrained areas.⁸¹

7 **Q: Are there examples of data centers paying for customer-sited resources?**

8 A. Yes. In Minnesota, Google and Xcel, as part of the Pine Island data center project, came to
9 an agreement in which Google will pay \$50 million to support Xcel's Capacity*Connect
10 Program, which is designed to install battery energy storage systems on the distribution
11 grid to increase capacity and grid resilience.⁸² In Indiana, Google recently contributed
12 \$700,000 to communities located near new Google data centers with part of the funding
13 dedicated to installation of solar and battery energy storage systems for LMI households.⁸³
14 Additionally, Google recently announced a Bring Your Own Capacity agreement under
15 which Google will fund a VPP consisting of 100 MWs of DERs from local businesses and
16 homes in PJM.⁸⁴

17 **Q: How would the VPP participate in the MISO wholesale market?**

⁸¹ Green Mountain Power Corporation, "Bring Your Own Device ("BYOD") Program," available at <https://epuc.vermont.gov/?q=downloadfile/399826/143817>.

⁸² Kobor, B., "Google is coming to Minnesota and advancing clean energy goals," February 24, 2026, available at <https://blog.google/innovation-and-ai/infrastructure-and-cloud/global-network/data-center-pine-island/>.

⁸³ Parker, C., "Google contributes \$700,000 in community support funding for data center communities," April 16, 2026, available at <https://www.21alivenews.com/2026/04/16/google-contributes-700000-community-support-funding-data-center-communities/>.

⁸⁴ Google, "We've signed a first-of-its-kind agreement with Voltus to create a smart capacity solution for the grid," June 2, 2026, available at <https://blog.google/company-news/outreach-and-initiatives/sustainability/voltus-agreement/>.

1 A: Importantly, as an initial starting point, DTE's DR portfolio (including the Smart Savers
2 program) approximates a basic VPP and is, as described above, registered as LMRs with
3 MISO. As this VPP expands with the addition of new Smart Savers customers (with the
4 additional incentives and new PCTs paid for by the Customer), the additional ZRCs
5 provided can be registered with MISO and accounted for as part of the 300 ZRCs needed
6 from the Customer. These customer outreach, installation, and enrollment activities can
7 begin immediately upon Commission approval of this case, ensuring these ZRCs will be
8 easily available by 2028. Pursuing existing supply-side pathways is the appropriate
9 approach to meet the Customer's 300 ZRC obligation within the initial time period.
10 Because Smart Savers is already part of the Company's MISO LMR portfolio, incremental
11 enrollments funded by the Customer would produce additional ZRCs as soon as those
12 customers are enrolled.

13 At the same time, it is crucial that the Company expeditiously move to establish a
14 VPP program (as described above) by (1) enrolling existing behind-the-meter customer-
15 owned battery energy storage plus solar systems and (2) enrolling new customer-owned
16 battery energy storage plus solar systems with the upfront and performance incentives paid
17 for by the Customer. It is critical that the processes, procedures, and program are
18 established in the near-term to enable the VPP to provide ZRCs by 2030 when Federal
19 Energy Regulatory Commission ("FERC") Order 2222 will be fully implemented by
20 MISO. FERC Order 2222 requires Regional Transmission Organizations ("RTOs") and
21 Independent System Operators ("ISOs") to create a pathway for DER aggregations to
22 participate in wholesale markets. Distributed Energy Aggregated Resources ("DEARs")

1 will be able to start registering with MISO on June 1, 2029 and will be able to participate
2 in the MISO markets at the start of 2030.^{85, 86}

3 This timeline will allow the Company and the Customer time to expand the
4 Company's DR program (providing some of the initial needed 300 ZRCs), establish utility
5 controls (including necessary utility and grid edge DER management systems), develop an
6 expanded VPP program, explore options for third-party aggregators to implement the
7 program, enroll existing customer-owned battery energy storage plus solar systems, and
8 enroll additional new customer-owned battery energy storage plus solar systems. As these
9 systems are enrolled, prior to DEAR registration with MISO, these resources could be
10 registered as LMRs through the Company's existing DR programs. This pathway will
11 allow more near-term contribution of battery energy storage plus solar systems toward the
12 300 ZRCs needed as part of the CCAA by 2028.

13 By the time that DEARs can participate in the MISO market in 2030, these initial
14 steps will be well established. In other words, the MISO's DEAR registration window
15 (opening June 1, 2029, with market participation beginning in 2030) fits comfortably inside
16 the CCAA term—allowing time to establish program tariffs, aggregator contracts, and
17 measurement and verification protocols before the VPP begins contributing ZRCs through
18 that pathway.

19 **Q: Should other resources in addition to PCTs and battery energy storage plus solar**
20 **systems be included?**

⁸⁵ Federal Energy Regulatory Commission, Order on Compliance Filing, Docket No. ER22-1640-003, January 16, 2025.

⁸⁶ Importantly, aggregations of battery energy storage plus solar systems or other DERs with DR cannot be prohibited by state commissions from participation in the wholesale market in the same manner that DR-only aggregations can be.

1 A: A successful VPP program should be technology agnostic, utilizing all DR and DER
2 technologies can be controlled remotely and provide the needed resources. The proposal in
3 my testimony should simply be viewed as an initial starting point to serve a specific need
4 (*i.e.*, ZRCs paid for by the Customer and provided to the Company).

5 **Q: What other benefits would these resources provide?**

6 A: It is critical that the enrollment requirements for battery energy storage plus solar systems
7 in the VPP allow customers to use their system for backup power during outages. This is
8 an especially relevant benefit for the state of Michigan and for LMI customers who may
9 be more impacted by the economic and health impacts of a prolonged outage. Although
10 the state's major utilities have improved their reliability performance over the last several
11 years, Michigan still lags behind many states in key reliability metrics, including the
12 average time it takes to restore power after an outage.^{87, 88} Well-designed VPPs, such as
13 Rocky Mountain Power's Wattsmart program, allow customers to utilize energy storage
14 for backup during outages while accessing the batteries for load control and grid benefits
15 at other times.⁸⁹

16 In addition, the future VPP program can provide additional benefits to the Company
17 beyond the direct ZRC benefits needed in this case. Specifically, the PCTs and battery
18 energy storage plus solar systems can be used to reduce the Company's PRMR. These

⁸⁷ Michigan Public Service Commission, "Michigan making big improvements in reliability and affordability," February 2026, available at <https://content.govdelivery.com/accounts/MILARA/bulletins/40bc6bc>.

⁸⁸ Michigan Citizens Utility Board, "Utility Performance Report: Ranking Michigan Among the States," 2025, available at https://cubofmichigan.org/wp-content/uploads/2025/09/2025-Utility-Performance-Report_20250904.pdf.

⁸⁹ Rocky Mountain Power, "Wattsmart Battery Program Customer Information," available at https://www.rockymountainpower.net/content/dam/pcorp/documents/en/rockymountainpower/savings-energy-choices/wattsmart-batteries/RMP_BatteryStorageProgram_customer_FINAL.pdf.

1 distribution-connected assets can avoid transmission losses, thereby contributing higher
2 equivalent capacity values at the bulk system level.⁹⁰

3 **Q: What do you recommend with respect to customer-sited resources?**

4 A: The Company already anticipates enrolling an additional 40,000 PCTs in the Smart Savers
5 program to provide nearly 94 MW of demand response by the 2028/29 Planning Year.⁹¹
6 Given that only about 50% of respondents to the 2025 Michigan Energy Waste Reduction,
7 Demand Response, and Efficient Electrification Statewide Potential Study were aware of
8 the utility DR programs, with increased awareness, new enrollments, and an OEM-led
9 pathway (using funding and incentives provided by the Customer), it seems that a
10 significant additional number of ZRCs could be provided.

11 Conservatively, I recommend that the Customer provide at least 100 ZRCs (of the
12 300 ZRCs required under the CCAA) from expanded participation in the Smart Savers
13 program including by enrolling existing PCTs, enabling an OEM-led enrollment pathway,
14 and subsidizing installation of new PCTs. To the extent the OEM-led pathway cannot be
15 registered with MISO, the resulting reduction in the Company's PRMR provides an
16 equivalent capacity benefit and should be credited toward fulfillment of the Customer's
17 CCAA obligation accordingly.

18 Separately, I recommend that the Customer work with the Company to provide
19 enrollment and pay-for-performance incentives to enroll 50% of the Company's existing
20 battery energy storage plus solar customers (approximately 4.5 MW) by early 2030 in a
21 VPP program to provide peak load reduction and ZRCs. Additionally, the Customer should

⁹⁰ MISO, "Business Practice Manuals: BPM 011- Resource Adequacy," available at <https://www.misoenergy.org/legal/rules-manuals-and-agreements/business-practice-manuals/>, Section 4.2.

⁹¹ Direct Testimony of Marcus B. Leuker on behalf of DTE Electric Company, Case No. U-22046, p. 44.

1 provide incentives to install new customer-owned behind-the-meter battery energy storage
2 plus solar systems for an additional 2,000 ratepayers. If each of these battery energy storage
3 systems were 5 kW in capacity, this would provide an additional 10 MW of capacity. As
4 described above, because customers should still have access to the battery for backup
5 power during outages, the entirety of this capacity will not be available to the program.

6 These recommendations represent a conservative starting point. Market evidence
7 demonstrates that residential battery energy storage system deployments at significantly
8 greater scale are achievable within the proposed timeline. In Texas, a residential battery
9 company signed partnerships with five utilities totaling over 290 MW of distributed
10 residential battery capacity between 2025 and May 2026, including a single 100 MW
11 program targeting deployment of 5,000 homes within two years.⁹² The company's head of
12 utility partnerships stated that the company can deliver dispatchable capacity equivalent to
13 a gas peaker plant "in two years by striking deals with homeowners and installing each
14 system in a day."⁹³ Nationally, the residential battery energy storage sector installed 3.1
15 GWh of new capacity in 2025 alone—a 51% year-over-year increase—sufficient to equip
16 more than 100,000 homes at the system size proposed herein (depending on the percentage
17 of battery capacity available to the VPP program).⁹⁴ Deployments of 20,000 homes in a
18 two-year window—producing nearly 100 MW of sustained dispatchable capacity—are
19 achievable given existing contractor capacity, supply chains, and installer networks, and
20 are consistent with the pace of deployment demonstrated in comparable programs.

⁹² Spector, J., Canary Media, "Base Power to launch 100-MW home battery network for Texas utility," available at <https://www.canarymedia.com/articles/batteries/base-power-to-launch-100-mw-home-battery-network-for-texas-utility>.

⁹³ *Id.*

⁹⁴ Solar Energy Industries Association, "Energy Storage Market Outlook 2026," February 23, 2026, available at <https://seia.org/research-resources/energy-storage-market-outlook-q1-2026/>.

1 **IV. FINANCIAL INCENTIVE FOR ZRCS**

2 **Q: What is Michigan’s Financial Compensation Mechanism (“FCM”)?**

3 A: The FCM was first established in Public Act 341 of 2016.⁹⁵ It is a financial incentive
4 provided to a utility for the procurement of third-party owned resources and is designed to
5 both address the lost earnings opportunities as well as the imputed debt that may be argued
6 is associated with these contracts. Under the initial statute, utilities could request an FCM
7 for a PPA or for PPAs procured to fulfill a specific need, but the Commission was not
8 required to grant an FCM. In addition, a utility was able to seek an FCM that did not exceed
9 the utility’s weighted average cost of capital.⁹⁶

10 **Q: What role can an FCM play in addressing ownership bias by a utility?**

11 A: As described above, there exist strong existing financial incentives, such as the ability to
12 earn a return on capital expenditures, for an investor-owned utility to own all of the
13 facilities from which the utility obtains electricity instead of contracting for energy and
14 capacity using PPAs. This can create a situation where an investor-owned utility is
15 incentivized to avoid projects other than those that it builds itself or purchases from a
16 developer after construction is complete (*i.e.*, through a BTA). An FCM establishes an
17 incentive payment to a utility when it procures resources through a PPA, helping to address
18 this existing ownership bias. It is important to note that although the FCM is a direct
19 payment to the utility (and not to the third-party owner, and thus not a cost attributable to
20 the third-party project), the FCM may increase the total evaluated cost of PPA projects.⁹⁷

⁹⁵ Sections 6s(6) and 6t(15) of Public Act 341 of 2016.

⁹⁶ Sections 6s(6) and 6t(15) of Public Act 341 of 2016.

⁹⁷ Although not the subject of this testimony, I would argue that PPAs should be evaluated on a cost basis without the inclusion of the FCM given that it is not a payment to the third-party and only serves to both incentivize a utility with a financial benefit and advantage utility-owned projects from a cost perspective. Evaluating PPAs on a cost basis *with* the inclusion of the FCM undermines the policy behind the FCM—to incentivize utility selection of PPAs—by in fact handicapping them instead.

1 **Q: How did the passage of PA 235 of 2023 change the existing FCM?**

2 A: PA 235 of 2023 made two important changes to the existing FCM paradigm.⁹⁸ First, the
3 law specifies that for any PPA entered into after June 30, 2024, “the [C]ommission *shall*
4 authorize a financial incentive” (*i.e.*, without Commission discretion).⁹⁹ Second, the law
5 states that the FCM will be calculated as the product of contract payments multiplied by
6 the utility’s pre-tax weighted average cost of permanent capital. In other words, PA 235
7 mandated that the FCM is guaranteed (not discretionary) for future PPAs and established
8 the required value of the FCM. Prior to this change, the Commission had discretion to
9 approve a lower FCM or deny the FCM altogether.¹⁰⁰

10 **Q: What does the Company propose in this case with respect to an FCM?**

11 A: As described previously, under the CCAA, the Customer will transfer 300 ZRCs to the
12 Company without any cost. In addition, according to witness Foley,
13 the Customer has agreed to pay the Company an amount based on the
14 Financial Compensation Mechanism (“FCM”) that the Company is
15 authorized to receive for PPAs it enters into associated with clean
16 energy projects. More specifically, the Customer will pay the Company
17 an amount equal to the ZRCs transferred to the Company multiplied by
18 MISO Cost of New Entry (“CONE”) multiplied by the Company’s pre-
19 tax weighted average cost of permanent capital (“financial adder”). The
20 Company is proposing that it be allowed to record this amount as non-
21 refundable income, like it does with the FCM.¹⁰¹

22 **Q: Does the FCM have any relationship to the transfer of ZRCs to the Company?**

23 A: Not to my knowledge. The transfer of ZRCs to the Company from the Customer is
24 proposed to be completed without any cost to the Company. There should be no lost
25 earnings opportunities or imputed debt associated with this transfer of ZRCs. Instead, it

⁹⁸ Section 28(8) of Public Act 235 of 2023.

⁹⁹ *Id.* (emphasis added).

¹⁰⁰ Sections 6s(6) and 6t(15) of Public Act 341 of 2016.

¹⁰¹ Foley Direct at 32.

1 appears that this payment, which is based on the FCM that the Company is authorized to
2 receive for PPAs it enters into, is simply meant to provide the Company with additional
3 revenue.

4 **Q: Why does the Company believe it should be paid this financial adder?**

5 A: According to a discovery response (Exhibit MEICEO-37) in this case,

6 The “financial adder” is intended to account for the opportunity cost of
7 foregoing the development of a company-owned resource or a third-party
8 resource that would receive an FCM, such as a PPA.

9 **Q: Do you agree with this premise?**

10 A: No. The CCAA includes up to 1,600 MW of Company-owned renewable energy resources
11 and up to 480 MW of energy storage. It seems entirely reasonable that the Company could
12 have procured or built additional resources to meet the identified capacity need but
13 determined not to pursue those options. It does not seem necessary to provide the Company
14 with a financial adder for taking ZRCs without cost.

15 **Q: What is the impact of the Company’s proposal to record this financial adder as non-**
16 **refundable income?**

17 A: By treating the proposed financial adder as non-refundable income, the Company is able
18 to use the income to improve its financial metrics and benefit shareholders. The Company
19 already recovers its costs associated with system planning, reliability management,
20 integration, and utility operations through existing rates and authorized returns. Traditional
21 utility earnings are generally justified where shareholders place capital at risk through
22 utility investment. Here, however, the Company is not placing incremental capital at risk
23 in exchange for the ZRC transfer. Rather, the Company is receiving ZRCs that count
24 toward the Company’s PRMR under MISO’s resource adequacy requirements. Allowing
25 the Company to additionally retain the financial adder as non-refundable income would

1 therefore provide shareholders with an additional (duplicative) earnings stream
2 disconnected from incremental utility investment or uncompensated risk.

3 **Q: What do you recommend with respect to the financial adder?**

4 A: I do not believe that a financial adder is beneficial or necessary in this case and, as such,
5 should be rejected by the Commission. However, to the extent that it is approved by the
6 Commission, because the proposed financial adder more closely resembles a reduction in
7 net system costs than a shareholder earnings opportunity, it should be treated as a cost
8 offset and be used to lower revenue requirements for all ratepayers.

9 **V. RECOMMENDATIONS**

10 **Q: Please summarize your recommendations to the Commission.**

11 A: I recommend that the Commission:

- 12 • Encourage the Company to procure proportionally greater capacity from third-party
13 owned energy storage projects, especially to the extent that such projects are lower cost
14 than comparable Company-owned projects;
- 15 • Require the Company to procure equivalent MWs of renewable energy resources to
16 fulfill demand for the CRO Special Contract from third-party owned projects (50%)
17 and Company-owned BTA/self-built projects (50%);
- 18 • Require the Company to work with the Customer to provide at least 100 of the needed
19 300 ZRCs from expanded participation in the Smart Savers program including through
20 an OEM-led pathway and the subsidized installation of new PCTs;
- 21 • Require the Company to establish an initial VPP program with stakeholder input within
22 nine months of the Commission's final order in this case including program tariffs,

1 aggregator contracts, enrollment channels, and measurement and verification
2 protocols;

- 3 • Require the Customer to work with the Company to provide enrollment and pay-for-
4 performance incentives to enroll at least 50% of the existing battery energy storage plus
5 solar customers (approximately 4.5 MW) in the VPP program to provide peak load
6 reduction and ZRCs;
- 7 • Require the Customer to work with the Company to provide incentives (scaled to
8 income) to install at least 2,000 new customer-owned behind-the-meter battery energy
9 storage plus solar systems;
- 10 • Reject the financial adder for the transfer of ZRCs; and
- 11 • To the extent the Commission approves the proposed financial adder for the transfer of
12 ZRCs, require the Company to account for that financial adder as a cost offset and not
13 as non-refundable income.

14 **Q: Does that complete your testimony?**

15 **A:** Yes.

1 MS. DUCKWORTH: Thank you. Finally,
2 MEICEO have come to an agreement with the Company to the
3 admission of one hearing room exhibit in lieu of cross-
4 examination of Company witnesses; this exhibit consists
5 of discovery responses provided by the Company in
6 response to MEICEO and is uploaded to the SharePoint in
7 the MEICEO folder under a subfolder titled Hearing
8 Exhibits. At this time, I would like to move for the
9 admission of Exhibit MEICEO-38.

10 JUDGE STALEY: Any objection to the
11 admission of Exhibit MEICEO-38?

12 Hearing none, Exhibit MEICEO-38 is
13 admitted into evidence.

14 MS. DUCKWORTH: Thank you, your Honor.
15 At this time, MEICEO rests our case.

16 JUDGE STALEY: Thank you, Ms. Duckworth.
17 And I believe that leaves Staff.

18 MR. SONNEVELDT: Thank you, your Honor.
19 At this point, Staff would move to bind in the Direct
20 Testimony of Cody S. Matthews. Mr. Matthews' direct
21 testimony consists of nine pages that includes a cover
22 page and eight pages of questions and answers. He
23 sponsors no exhibits. Mr. Matthews also filed rebuttal
24 testimony, it consists of four pages, including a cover
25 page with three pages of questions and answers, no

1 exhibits.

2 JUDGE STALEY: Is there any objection to
3 the binding in of the prefled Direct and Rebuttal
4 Testimony of Cody S. Matthews?

5 Hearing none, the prefled Direct and
6 Rebuttal Testimony of Cody S. Matthews are bound into the
7 record.

8 (Direct Testimony and Rebuttal Testimony bound in.)

9 - - -

S T A T E O F M I C H I G A N
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * *

In the matter of the application of	)	Case No. U-22058
DTE ELECTRIC COMPANY	)	
for approval of special contracts	)	
<u>and for other relief</u>	)	

QUALIFICATIONS AND DIRECT TESTIMONY OF
CODY S. MATTHEWS
MICHIGAN PUBLIC SERVICE COMMISSION

June 5, 2026

QUALIFICATIONS OF CODY S. MATTHEWS
CASE NUMBER U-22058
PART I

1 Q. Please state your name and business address.

2 A. My name is Cody S. Matthews. My business address is 7109 W. Saginaw Hwy.,
3 Lansing, Michigan 48917.

4 Q. By whom are you employed and in what capacity?

5 A. I am employed by the Michigan Public Service Commission (MPSC or
6 Commission) as the manager of the Interconnection and Distributed Energy
7 Resources Section of the Energy Operations Division.

8 Q. Please describe your educational background.

9 A. I earned a Bachelor of Science degree in Engineering from Michigan State
10 University in 2014.

11 Q. Would you please describe your professional background.

12 A. In 2014 I began working for the MPSC in the Smart Grid Section. I reviewed
13 sections of utility rate case filings that pertained to smart grid, advanced metering
14 infrastructure (AMI), demand response (DR), information technology (IT), and
15 cyber security. In 2019 I transferred into the Renewable Energy Section, which
16 was renamed the Interconnection and DER section as of August 2022. In 2024 I
17 was promoted to manager of the Interconnection and DER section and am
18 focusing on electric utility interconnection, interconnection procedures, demand
19 response (DR), distributed energy resources (DERs), and distributed generation
20 (DG) programs.

21 Q. Have you received any work-related training since starting your employment with
22 the MPSC?

QUALIFICATIONS OF CODY S. MATTHEWS
CASE NUMBER U-22058
PART I

A. Yes. I have attended several programs hosted by the Institute of Public Utilities at Michigan State University, including Introduction to Public Utility Regulation, the full two-week fundamental and intermediate course, and the Advanced Regulatory Studies Program, as well as the Michigan Forum on Economic Regulatory Policy and the Rate Making Course. Additionally, I have participated in several conferences both in person and online concerning cyber security, IEEE 1547, and other renewable energy related topics.

Q. Have you previously testified before the Commission?

A. Yes, I have testified in the following cases:

<u>Case Number</u>	<u>Company</u>	<u>Case Type/Subject</u>
U-17767	DTE Electric Company	Rate Case
U-17999	Consumers Gas Company	Rate Case
U-18014	DTE Electric Company	Rate Case
U-18255	DTE Electric Company	Rate Case
U-18370	Indiana Michigan Power Co.	Rate Case
U-18999	DTE Gas Company	Rate Case
U-20137	Indiana Michigan Power Co.	Opt-Out Tariff
U-20162	DTE Electric Company	Rate Case
U-20165	Consumers Energy Company	IRP
U-15800	Commission's Own Motion	2019 Transfer Price
U-18091	DTE Electric Company	Avoided Cost Update
U-20350	Upper Peninsula Power Co.	IRP
U-20471	DTE Electric Company	IRP

QUALIFICATIONS OF CODY S. MATTHEWS
CASE NUMBER U-22058
PART I

1	U-20485	Indiana Michigan Power Co.	RE Recon
2	U-20591	Indiana Michigan Power Co.	IRP
3	U-15800	Commission's Own Motion	2020 Transfer Price
4	U-20561	DTE Electric Company	Rate Case
5	U-18232	DTE Electric Company	RE Plan
6	U-20697	Consumers Energy Company	Rate Case
7	U-20713	DTE Electric Company	VGP
8	U-15800	Commission's Own Motion	2021 Transfer Price
9	U-20851	DTE Electric Company	RE Plan
10	U-20963	Consumers Energy Company	Rate Case
11	U-21090	Consumers Energy Company	IRP
12	U-21009	Consumers Energy Company	RE Plan
13	U-21081	UMERC	IRP
14	U-21010	DTE Electric Company	RE Recon
15	U-21148	Consumers Energy Company	Rate Case
16	U-15800	Commission's Own Motion	2022 Transfer Price
17	U-21189	Indiana Michigan Power Co.	IRP
18	U-20836	DTE Electric Company	Rate Case
19	U-21224	Consumers Energy Company	Rate Case
20	U-21286	Upper Peninsula Power Co.	Rate Case
21	U-20803	Consumers Energy Company	PSCR Recon
22	U-21198	DTE Electric Company	RE Recon
23	U-21197	Consumers Energy Company	RE Recon

QUALIFICATIONS OF CODY S. MATTHEWS
CASE NUMBER U-22058
PART I

1	U-21193	DTE Electric Company	IRP
2	U-21172	DTE Electric Company	VGP
3	U-21297	DTE Electric Company	Rate Case
4	U-15800	Commission's Own Motion	2023 Transfer Price
5	U-21389	Consumers Energy Company	Rate Case
6	U-21410	Consumers Energy Company	DR Recon
7	U-21374	Consumers Energy Company	VGP
8	U-21353	DTE Electric Company	RE Recon
9	U-21352	Consumers Energy Company	RE Recon
10	U-18091	DTE Electric Company	Avoided Cost Update
11	U-15800	Commission's Own Motion	2024 Transfer Price
12	U-21534	DTE Electric Company	Rate Case
13	U-21555	Upper Peninsula Power Co.	Rate Case
14	U-21482	DTE Electric Company	Interconnection Procedures
15	U-21260	DTE Electric Company	2023 PSCR Plan
16	U-21841	Indian Michigan Power Co.	2023/2024 DR Recon
17	U-21860	DTE Electric Company	Rate Case
18	U-21906	Consumers Energy Company	2024 DR Recon
19	U-21972	Consumers Energy Company	VGP

QUALIFICATIONS OF CODY S. MATTHEWS
CASE NUMBER U-22058
PART II

1 Q. What is the purpose of your testimony?

2 A. The purpose of my testimony is to present the MPSC Staff's (Staff)
3 recommendations for DTE Electric Company's (DTE or the Company)
4 emergency electrical procedures in section C3 of its rate book for electric service.

5 Q. Are you sponsoring any exhibits in the proceeding?

6 A. No.

7 Q. Has the Commission previously cited concerns regarding large load customers
8 and system reliability?

9 A. Yes. In the Commission's order in MPSC Case No. U-21859 the Commission
10 noted that the significant increase in load represented by data centers and other
11 large load customers pose several potential risks related to system reliability.¹

12 Q. Has DTE proposed any changes or modifications concerning its emergency
13 electric procedures in its filing in the instant case?

14 A. DTE did not include any references or proposed language concerning the
15 emergency procedures pertaining to this special contract approval request.

16 Q. Has the Commission addressed DTE's emergency procedures in any other similar
17 filings?

18 A. Yes. In MPSC Case No. U-21990, DTE's request for approval of a special
19 contract with Oracle, the Commission's Dec 18, 2025 order addressed DTE's
20 emergency procedures, stating:

¹ MPSC Case No. U-21859, 11/6/25 Commission Order, p 103.

QUALIFICATIONS OF CODY S. MATTHEWS
CASE NUMBER U-22058
PART II

1 in order to ensure that the addition of this significant new load will not
2 adversely impact the grid reliability experienced by other customers, DTE
3 Electric is directed, within 90 days of the date of this order, to file an application
4 to update its Emergency Electric Procedures outlined in Section C3 of its Rate
5 Book for Electric Service and any other relevant DTE Electric procedures to
6 indicate that, after the event level step including the issuance of public appeals
7 and after the event level step that implements voluntary load reductions, the
8 company will shed firm load from the Customer prior to shedding firm load of
9 any of DTE Electric's other customers to the extent that firm load shedding is
10 directed by the regional transmission organization and shedding the load of the
11 Customer can prevent shedding load of other DTE Electric customers.²

12 Q. Has DTE updated its emergency procedures pursuant to the Commission's order
13 in U-21990?

14 A. On March 18, 2026 DTE filed an amendment to the emergency procedures,
15 section C3 of its rate book, in MPSC Case No. U-22059.

16 Q. Has the Commission approved DTEs proposed rate book amendments?

17 A. To date the Commission has not approved DTE's proposed amendments to its
18 emergency procedures.

19 Q. Would DTE's proposed amendment be applicable to the special contract at issue
20 in the instant case?

² MPSC Case No. U-21859, 11/6/25 Commission Order, p 103

QUALIFICATIONS OF CODY S. MATTHEWS
CASE NUMBER U-22058
PART II

1 A. Yes. As proposed, DTE's amended emergency procedures include provisions that
2 would apply to the contract in the instant case. Specifically, DTE's amended
3 procedures say the following:

4 As a measure of last resort, manual load shedding of firm customer loads
5 will be instituted as necessary to maintain the integrity of the system.
6 Customers that take service from DTE Electric after October 1, 2025 with
7 capacity of at least 500MW or customers that take service under the Large
8 Load Provision of Rate Schedule No. D11 will be subject to firm load
9 shedding prior to other customers, provided that such customer load
10 shedding 1) does not compromise system reliability and 2) can prevent
11 shedding the firm load of other DTE Electric customers.³
12

13 Because DTE's proposed changes to its emergency procedures in MPSC Case U-
14 22059 include provisions that apply to any customers over 500MW or that take
15 service under the proposed large load provision under rate D11, the special
16 contract in the instant case would fall under those provisions.

17 Q. If the Commission does not approve the proposed emergency procedures
18 amendments in MPSC Case No. U-22059, please describe Staff's
19 recommendation.

20 A. If the Commission does not approve the proposed amendment to emergency
21 procedures in MPSC Case No. U-22059, then Staff recommends one of the
22 following actions take place: DTE amend this special contract to include language
23 to address the Commission's concerns it laid out in its U-21990 order, or DTE
24 amend its emergency procedures language to ensure that any provision in its
25 emergency procedures tariff also apply to this special contract.

³ MPSC Case No. U-22059, Attachment A p1.

QUALIFICATIONS OF CODY S. MATTHEWS
CASE NUMBER U-22058
PART II

1 || Q. Does this conclude your testimony?

2 || A. Yes.

S T A T E O F M I C H I G A N
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of,)
DTE ELECTRIC COMPANY)
 for approval of special contracts and for other relief.)
 _____)

Case No. U-22058

REBUTTAL TESTIMONY OF

CODY S. MATTHEWS

MICHIGAN PUBLIC SERVICE COMMISSION

June 17, 2026

**REBUTTAL TESTIMONY OF CODY S. MATTHEWS
CASE NUMBER U-22058**

1 Q. Are you the same Cody S. Matthews that filed direct testimony in this proceeding?

2 A. Yes. I am.

3 Q. What is the purpose of your rebuttal testimony?

4 A. The purpose of my rebuttal testimony is to provide Staff's position on certain
5 recommendations in Laura S. Sherman's direct testimony on behalf of Michigan Energy
6 Innovation Business Council, Institute for Energy Innovation, Ecology Center, Environmental
7 Law & Policy Center, Union of Concerned Scientists, and Vote Solar (Collectively MEI/CEO).

8 Q. Are you sponsoring any exhibits?

9 A. No, I am not.

10 Q. What are the specific recommendations by MEI/CEO witness Sherman you are rebutting?

11 A. Staff has specific concerns about the appropriateness of the following of MEI/CEO witness
12 Sherman's recommendations:

13 1. The discussion on the source of 300 ZRCs that are transferred to the Company under the CCAA
14 as discussed in MEIU/CEO witness Sherman's testimony that includes demand response and a
15 virtual power plant program inclusive of behind the meter storage. (MEIU/CEO witness Sherman
16 Direct Testimony, pages 24-42.)

17 Q. What are Staff's concerns with MEI/CEO witness Sherman's recommendations about
18 fulfilling a portion of the 300 ZRCs with demand response, virtual power plant programs, or behind
19 the meter storage?

20 A. First, Staff's opinion is that it is unnecessary and inappropriate to impose requirements
21 beyond those included in the contracts between the Customer and the Company on the source of
22 the ZRCs being provided by the Customer at no cost to the Company, and MEI/CEO witness
23 Sherman has not supported why it would be necessary or appropriate to do so. Additionally, Staff

REBUTTAL TESTIMONY OF CODY S. MATTHEWS
CASE NUMBER U-22058

1 is concerned that, although these ZRCs would be delivered to the Company at no cost, the existence
2 of such programs would require some understanding about the cost of the utility to administer
3 those programs. Exactly how the programs are credited to the participants may not align with just
4 the value of a ZRC in the MISO market or bilateral capacity market, so expecting the Customer to
5 pay more such that the programs identified can exist to fulfill a portion of the 300 ZRCs in the
6 CCAA may not be reasonable. For example, on page 35 of MEI/CEO witness Sherman's direct
7 testimony, the recommendation is made to utilize currently deployed behind the meter storage as
8 a VPP. While Staff agrees that behind the meter storage is an excellent candidate for a VPP, there
9 are many aspects of those installations, such as the backend requirements of the utility, that are
10 unknown and may be very costly to implement. An operational distributed energy resource
11 management system (DERMs) would be essential for managing the storage, given the variety of
12 manufacturers, inverters, and settings being used in those installations. Further, it is likely that
13 very few of those installations are currently capable of exporting power to the grid, as DTE's
14 interconnection procedures only allow for storage to be in one of three acceptable modes: import
15 only, export only, or no exchange.¹ Given that there is very little benefit to a customer being on
16 export only mode, it is likely that the majority of customers are either on import only or no
17 exchange modes, which do not allow the storage to export onto the grid. With the limited capability
18 of customers to send power back to the grid from behind the meter battery resources, the actual
19 impact of any storage would be far less than its available capacity. Given these unknowns, if the
20 Commission determines that behind the meter storage should be used, it should require DTE to
21 update its interconnection procedures to allow behind the meter storage to export to the grid

¹ <https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs00001NdbbVAAR> p 7.

REBUTTAL TESTIMONY OF CODY S. MATTHEWS
CASE NUMBER U-22058

1 | directly. To the extent that there is a solicitation for the ZRCs procured by the Customer, there
2 | may be an opportunity for a developer or the utility to bid in.

3 | Q. Does this conclude your testimony?

4 | A. Yes, it does.

1 MR. SONNEVELDT: Next, your Honor, Staff
2 would move to bind in the Direct Testimony of Naomi J.
3 Simpson. Ms. Simpson's direct testimony consists of 18
4 pages that includes a cover page with 17 pages of
5 questions and answers. She also sponsors Exhibits S-1.0,
6 1.1, 1.2, and 1.3 in her direct testimony. Ms. Simpson
7 also filed rebuttal testimony that consists of three
8 pages, including a cover page and two pages of questions
9 and answers. She sponsors no exhibits in her rebuttal
10 testimony.

11 JUDGE STALEY: Thank you. Is there any
12 objection to the binding in of the prefiled Direct
13 Testimony and Rebuttal Testimony of Naomi J. Simpson, as
14 well as the admission of Exhibits S1.0, S-1.1, S-1.2, and
15 S-1.3?

16 Hearing none, the prefiled Direct and
17 Rebuttal Testimony of Naomi J. Simpson are bound into the
18 record, and Exhibits S-1.1 through S-1.3 are admitted
19 into the record.

20 (Direct Testimony and Rebuttal Testimony bound in.)

21 - - -
22
23
24
25

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of	)	
DTE ELECTRIC COMPANY	)	
for approval of special contracts and	)	Case No. U-22058
related relief.	)	
_____	)	

QUALIFICATIONS AND DIRECT TESTIMONY OF
NAOMI J. SIMPSON
MICHIGAN PUBLIC SERVICE COMMISSION

June 5, 2026

QUALIFICATIONS OF NAOMI J. SIMPSON
CASE NUMBER U-22058
PART I

1 Q. Please state your full name and business address for the record.

2 A. My name is Naomi J. Simpson. My business address is the Michigan Public Service
3 Commission's (MPSC or Commission) work site at 7109 West Saginaw Highway,
4 Lansing, Michigan 48917.

5 Q. By whom are you employed and in what capacity?

6 A. I am employed in the Energy Resources Division of the MPSC. I am the Manager of the
7 Resource Optimization and Certification Section, which is responsible for assisting in the
8 implementation of Public Act 341 (PA 341) of 2016, as amended by Public Act 231 (PA
9 231) of 2023; implementation of the Commission's regulatory responsibilities under Public
10 Act 295 (PA 295) of 2008, as amended by Public Act 342 of 2016 and Public Act 235 (PA
11 235) of 2023, with particular focus on the implementation of Michigan's statewide energy
12 storage target and implementation of Michigan's clean energy standard (CES); and
13 evaluating applications for transmission siting pursuant to Public Act 30 of 1995.

14 Q. Would you please outline your educational background?

15 A. Yes. I earned a Bachelor of Science degree in Engineering from Michigan State University
16 in 1997 and a Master of Arts degree in Education from the University of Phoenix in 2010.
17 Since joining the Commission, I have also attended several training programs sponsored
18 by the National Association of Regulatory Utility Commissioners and Michigan State
19 University, including the Annual Regulatory Studies Program (August 2011, 2012, 2013),
20 the Advanced Regulatory Studies Program (October 2011, 2012, 2013, 2014), and
21 Introduction to Public Utility Regulation and Ratemaking (May 2012). In addition, I have
22 attended the Distribution Efficiency Planning and Voltage Optimization Conference
23 sponsored by Electric Utility Consultants, Inc. (June 2012); the annual Energy, Utility &

QUALIFICATIONS OF NAOMI J. SIMPSON**CASE NUMBER U-22058****PART I**

1 Environment Conference (January 2013); the National Energy Risk Lab (February 2014);
2 multiple EGEAS modeling training sessions at various Midcontinent Independent System
3 Operator (MISO) locations (2015, 2016, 2017, 2018, 2019); the Peak Load Management
4 Alliance (2016); the National Council on Electric Policy Workshop (2018); and
5 participated as a Michigan representative in the National Association of Regulatory Utility
6 Commissioners (NARUC) National Association of State Energy Officials Task Force
7 (2019-2020). Since 2024, I have participated in the Long Duration Energy Storage National
8 Consortium. I have also attended several Midwest Energy Efficiency Alliance (MEEA)
9 training sessions in 2024 and 2025 held at the two most recent MEEA conferences.

10 Q. Would you please outline your professional experience?

11 A. In September 1994, I began working at General Motors Corporation as a student engineer,
12 where I worked with staff engineers to evaluate vehicle calibrations and components
13 related to meeting vehicle emissions standards and fuel efficiency.

14 In February 1998, I began working as a staff Design and Release Engineer with
15 responsibility for vehicle platform exhaust systems in Delphi Automotive Systems, a
16 subsidiary of General Motors, which later became a fully independent corporation in 1999.
17 My duties as a Design and Release Engineer included design team management, durability
18 test validation, production approval, and lean manufacturing implementation. In August
19 2000, I became the Engineering Change Management Coordinator for the Delphi Lansing
20 Cockpit Assembly Plant, where I was responsible for model year program management
21 and mid-cycle engineering change management and was designated the Engineering
22 Liaison to the General Motors staff product engineers, manufacturing engineers, and
23 quality engineers associated with cockpit production. In 2002, I became the on-site

QUALIFICATIONS OF NAOMI J. SIMPSON**CASE NUMBER U-22058****PART I**

1 Systems, Applications & Products in Data Processing Project Manager for the Delphi
2 Lansing Cockpit Assembly Plant, in addition to my previous responsibilities. In November
3 2004, I was assigned the duties of Quality Manager, with responsibility for plant-wide first-
4 time quality goals, root cause analysis, supplier quality standards, and statistical defect
5 analysis.

6 In 2007, I accepted a position at Barnard Manufacturing, Inc. as a Commodity
7 Buyer of steel and aluminum raw material. My responsibilities included negotiation of
8 commodity contracts to create the most efficient pricing structure, while ensuring timely
9 delivery, creating material quality specifications, initiating build schedules based on
10 customer-desired completion dates, and maintaining a material pricing database for all
11 manufactured components.

12 In March of 2011, I accepted a position as a Public Utilities Engineer in the Smart
13 Grid Section of the MPSC. I was a member of the Smart Grid Collaborative as the co-
14 chair of the Customer Programs and Communication Work Group. In Case No. U-16794,
15 I supported MPSC Staff (Staff) witnesses with the analysis of Consumers Energy
16 Company's Advanced Metering Infrastructure / Smart Grid proposal and request for
17 recovery. I have also assisted with writing the Staff report to the Commission in Case No.
18 U-17000. Upon transfer to the Generation and Certificate of Need (nka Resource
19 Optimization and Certification) Section in May of 2012, I began testifying as an expert
20 witness in utility generation certificate of necessity application filings and utility
21 transmission certificate of public convenience and necessity application filings. In 2015,
22 the Commission established a Demand Response Programs Work Group, of which I remain
23 a member. In 2018, I accepted the position of Manager of the Resource Optimization and

QUALIFICATIONS OF NAOMI J. SIMPSON**CASE NUMBER U-22058****PART I**

1 Certification section in the Energy Resources Division that has the primary roles of leading
2 Staff's analysis of Public Act 341 of 2016, as amended by Public Act 231, Integrated
3 Resource Plan applications; Public Act 235 of 2023 Clean Energy Plan applications; Public
4 Act 286 of 2008 Certificate of Need applications; and Public Act 30 of 1995 Certificate of
5 Public Convenience and Necessity (CPCN) applications. Throughout 2020 and 2021, I led
6 the MI Power Grid Phase II Advanced Planning effort focused on integration of
7 transmission, generation resources, and distribution planning. In 2021 and 2022, I led the
8 MI Power Grid Phase III Advanced Planning effort, which resulted in the revised Michigan
9 Integrated Resource Planning Parameters and updated Integrated Resource Plan Filing
10 Requirements adopted by the Commission in October 2022. In 2020, the Commission
11 developed in internal battery storage team of which I remain a member. With the signing
12 of the 2023 Energy Laws, Public Acts 231 and 235, I continue to lead multiple efforts
13 related to the implementation of those Acts.

14 Q. Have you previously presented testimony before the Commission?

15 A. Yes. I prepared and filed testimony for the following cases:

- 16 1. Case No. U-16801, Indiana Michigan Power Company electric rate case.
- 17 2. Case No. U-17041, Michigan Electric Transmission Company, LLC's application
18 for a certificate of public convenience and necessity for the construction of a
19 transmission line.
- 20 3. Case No. U-17272, ATC Management Inc. and American Transmission Co.,
21 LLC's application for a certificate of public convenience and necessity for the
22 construction of a transmission line.

QUALIFICATIONS OF NAOMI J. SIMPSON**CASE NUMBER U-22058****PART I**

4. Case No. U-17429, Consumers Energy Company's application for a certificate of necessity for the Thetford Generating Plant.
5. Case No. U-17767, DTE Electric Company electric rate case.
6. Case No. U-18014, DTE Electric Company electric rate case.
7. Case No. U-18224, Upper Michigan Energy Resources Corporation's application for a certificate of necessity for two reciprocating internal combustion engine electric generation facilities.
8. Case No. U-18322, Consumers Energy Company electric rate case.
9. Case No. U-18255, DTE Electric Company electric rate case.
10. Case No. U-18419, DTE certificate of necessity case for a natural gas combined cycle electric generation facility.
11. Case No. U-20134, Consumers Energy Company electric rate case.
12. Case No. U-20165, Consumers Energy Company integrated resource plan case.
13. Case No. U-20202, Consumers Energy Company power supply cost recovery case.
14. Case No. U-20276, Upper Peninsula Power Company electric rate case.
15. Case No. U-20497, Michigan Electric Transmission Company, Wolverine Power Supply Cooperative, and Midwest Energy and Communication asset determination case.
16. Case No. U-20529, Indiana Michigan Power Company power supply cost recovery case.
17. Case No. U-21089, DTE Electric Company classification of assets case.
18. Case No. U-21090, Consumers Energy Company integrated resource plan case.

QUALIFICATIONS OF NAOMI J. SIMPSON**CASE NUMBER U-22058****PART I**

1 19. Case No. U-21193, DTE Electric Company integrated resource plan case.

2 20. Case No. U-21377, Indiana Michigan Power Company's application for a
3 certificate of necessity to construct a solar generation facility.

4 21. Case No. U-21471 (U-21471 consolidated with U-21742), Michigan Electric
5 Transmission Company's application for a certificate of public convenience and
6 necessity for the construction of transmission lines.

7 22. Case No. U-21809 consolidated with 21811, Upper Peninsula Power Company
8 integrated resource plan consolidated with its renewable energy plan.

9 Q. Have you assisted with other cases before the Commission?

10 A. Yes, I assisted Staff in the following integrated resource plan cases: U-20591, U-20350,
11 U-20470, U-20471, U-20300, U-21081, and U-21189.

DIRECT TESTIMONY OF NAOMI J. SIMPSON
CASE NUMBER U-22058
PART II

1 Q. What is the purpose of your testimony?

2 A. The purpose of my testimony is to provide Staff's recommendations to the Commission
3 regarding DTE Electric Company's (DTE or Company) request for approval of a Primary
4 Supply Agreement (PSA) and a Clean Capacity Accelerator Agreement (CCAA),
5 identified as the Special Contracts throughout my testimony. Specifically, I will be
6 providing some of Staff's recommendations for conditions of Special Contract approval
7 if the Commission chooses to grant DTE approvals requested in this case. These
8 recommendations include analyses that should be done in future planning cases to ensure
9 that other customers do not subsidize service to Google LLC (the Customer), Staff's
10 recommendation regarding the Company's Voluntary Green Pricing (VGP) program and
11 the treatment of renewable energy credits (RECs) generated by renewable resources
12 included in the CCAA, and recommendations regarding the Company's request to book
13 the financial compensation mechanism (FCM) whereby the Customer has agreed to pay
14 on 300 MW of MISO Zone 7 Zonal Resource Credits (ZRC) as non-refundable income.

15 Q. Are you sponsoring any exhibits?

16 A. Yes. I will be sponsoring the following exhibits:

17 Exhibit S-1.0, STDE-3.1a

18 Exhibit S-1.1, STDE-3.2

19 Exhibit S-1.2, STDE-1.2 and STDE-1.3

20 Exhibit S-1.3, STDE-1.6

21 Q. Please briefly describe the Special Contracts.

22 A. The PSA, as described in DTE witness Neal Foley's testimony, stipulates that the Customer
23 will receive electric service under the Company's Rates Schedule D11, which is the

DIRECT TESTIMONY OF NAOMI J. SIMPSON
CASE NUMBER U-22058
PART II

1 Company's Primary Supply rate, and establishes additional protections for the Company's
2 other customers that are not included in D11. The CCAA allows the Company to acquire
3 480 MW of energy storage projects and up to 1,600 MW of renewable energy projects and
4 recover the full costs of these projects from the Customer. In addition, the CCAA allows
5 the Company to receive 300 ZRCs from the Customer at no cost.

6 Q. Did the Company identify the resources proposed in the CCAA through a modeling process
7 similar to what is undertaken during an Integrated Resource Plan (IRP)?

8 A. No. Company witness Shawn D. Burgdorf states that "the modeling results are intended to
9 ensure resource adequacy needs were met with and without the Customer to evaluate the
10 impact on future costs."¹ They are not intended to determine the future generation resource
11 mix or provide a preview of the Company's proposed course of action in its next IRP.

12 Q. When is the Company planning to file its next IRP and first Clean Energy Plan (CEP)?

13 A. According to Company witness Burgdorf, the Company plans to file its next IRP later this
14 year and in accordance with the Commission's Order in Case No. U-21990, and the
15 Company also plans to file its next Amended Renewable Energy Plan (Amended REP)
16 alongside its IRP at that time.² As directed by Public Act 235 of 2023, Staff expects the
17 Company's Clean Energy Plan to be filed with its IRP as well.

18 Q. Does Staff have any recommendations for additional analysis that it finds should be
19 included with the Company's next IRP, Clean Energy Plan, or Amended REP filing?

20 A. Yes. Staff finds the need for additional analysis in this case to be similar to the Company's
21 request for Special Contract approval in Case No. U-21990. Therefore, Staff recommends

¹ Direct Testimony and Exhibits of Company witness Burgdorf, p. 7.

² *Id.*, at, p. 8.

DIRECT TESTIMONY OF NAOMI J. SIMPSON
CASE NUMBER U-22058
PART II

1 that the Commission adopt the same conditions that it directed in the December 18, 2025
2 order in that case, but that the analysis includes both of the Company's large load customers
3 rather than performing a separate analysis for each large load customer. Specifically, Staff
4 recommends that the Company's next Amended REP that is to be filed with its IRP and
5 CEP shall include all of the following, as specified on pages 43 and 44 of the Commission's
6 Order and modified to include both large load customers, listed below:

- 7 1. A comparison of the resource requirements needed to comply with the renewable
8 portfolio standard (RPS) targets, both with and without the Company's large load
9 customers' load and corresponding retail sales.
- 10 2. An analysis of options for recovery of any incremental costs of renewable portfolio
11 standard compliance that may result in a surcharge, such that the surcharge is not
12 collected on a per meter basis.
- 13 3. An analysis of equitable ways to recover the incremental costs of renewable
14 portfolio standard compliance, which ensures that costs and benefits are
15 appropriately distributed among rate classes.
- 16 4. In its next integrated resource plan application and its initial clean energy plan
17 application (filed together), DTE Electric Company shall include a comparison of
18 the resource requirements necessary to serve the Company's load and meet the
19 RPS, CES, and resource adequacy and reliability, both with and without the
20 addition of the Customer's load and Special Contract resources.

21 Q. For clarification, is Staff recommending that the Company do this analysis independently,
22 for both of the Company's large load customers?

DIRECT TESTIMONY OF NAOMI J. SIMPSON
CASE NUMBER U-22058
PART II

1 A. No. Staff is recommending that the large load customer loads, supply side resources paid
2 by the large loads, and demand side resources provided by the large loads be aggregated
3 for this analysis; Staff is not recommending a separate analysis for each large load
4 customer.

5 Q. How is the analysis that the Commission directed in Case No. U-21990 different from the
6 analysis that the Company has provided in this case?

7 A. The analysis that Staff is suggesting requires that the Company assess the total resources
8 needed to serve all customers, inclusive of its two large load customers, as compared to the
9 total resources needed to serve all customers, absent its two large load customers and their
10 Special Contract resources, in its next IRP. By comparing the results, the analysis that the
11 Commission directed will illustrate what additional resources are needed to serve the
12 Company's two large load customers to ensure reliability, resource adequacy, and
13 compliance with both the renewable portfolio standard and the clean energy standard. Case
14 No. U-21990 directed the Company to perform this analysis for just one large load
15 customer.

16 Q. Why is such an analysis important?

17 A. Consistent with the direction provided in the Commission's Order, p. 32, "the Commission
18 is conditioning its approval on the requirement that, at the very least, all current and future
19 costs caused by the Customer shall be covered by the Customer or by DTE Electric and
20 not existing customers." Staff witness David Isakson recommends the Commission apply
21 the same condition in this case. Such an analysis will provide data to aid in the
22 Commission's assessment and determination of whether or not the large load customers
23 are covering all current and future costs they cause.

DIRECT TESTIMONY OF NAOMI J. SIMPSON
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1 Q. How does the Company plan to procure the resources expected to be developed under the
2 Special Contracts in this case?

3 A. DTE witness Foley testifies on page 25 that the Special Contract resources will be procured
4 by issuing a Request for Proposal (RFP), following the Competitive Procurement
5 Guidelines and the terms of the Company's 2022 IRP Settlement, dated July 26, 2023.

6 Q. Does Staff have any recommendations regarding the Company's resource procurement?

7 A. Yes. Staff supports the use of the Competitive Procurement Guidelines established in Case
8 No. U-20852 and notes that Staff has been directed to convene a workgroup to address
9 potential revisions to the Competitive Procurement Guidelines for Rate-Regulated Electric
10 Utilities (not for Public Utility Regulatory Policies Act (PURPA) Compliance) in the
11 Commission's April 30, 2026 Order in Case No. U-20852. Staff recommends that the
12 Commission direct the Company to utilize the most recently adopted Competitive
13 Procurement Guidelines as appropriate and prioritize resources for meeting the Company's
14 IRP and those resources necessary to serve all customers first, such that the Customer is
15 not paying less for resources contracted under the CCAA as compared to the same
16 technology types contracted at a similar time for the purpose of meeting the IRP, Amended
17 REP, or CEP. In short, the Special Contracts should not result in the Company's other
18 customers paying more than the Special Contract customers for the same resources
19 contracted in a similar timeframe.

20 Q. Does Staff have any other recommendations to the Commission regarding the Special
21 Contracts and the Company's request to collect a Financial Compensation Mechanism
22 associated with resources acquired pursuant to the CCAA?

DIRECT TESTIMONY OF NAOMI J. SIMPSON
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1 A. Yes, Staff has two additional recommendations. The first recommendation is regarding the
2 transfer of RECs to the Customer under the CCAA term 4.3.1. The second recommendation
3 is regarding the Company's request to record the FCM associated with 300 MW of ZRCs
4 that the Customer has committed to transfer to the Company as non-refundable income,
5 like it does with the FCM pursuant to MCL 460.1028.

6 Q. Please describe Staff's recommendation regarding the transfer of RECs to the Customer,
7 as described under the CCAA term 4.3.1.

8 A. CCAA term 4.3.1 states that for each Renewable Energy Project in the Renewable
9 Portfolio, the Company shall deliver to the Customer and the Customer shall receive RECs
10 in an amount equal to the applicable REC Quantity by May 31st, following the end of the
11 calendar year in which such REC quantity was generated. It is Staff's understanding that
12 the RECs that will be delivered to the Customer are the RECs generated by the resources
13 that the Company is contracted to acquire through the CCAA and that the Customer will
14 only receive renewable energy credits in the amount that is generated directly by those
15 resources. Staff recommends the Company confirm whether or not that is true. In addition,
16 the Company provided a response to Staff's audit, Staff Exhibit S-1.0. The Company's
17 response confirmed that the RECs that it delivers to the Customer are not necessarily going
18 to be retired by the Customer or on the Customer's behalf. Staff's opinion is that this is in
19 conflict with the Commission's July 12, 2017 Order in Case No. U-18349 that states the
20 following:

21 "The Commission agrees that some system, such as MIRECS, should be used
22 to track RECs under the VGP programs. Using the same system to track RECs
23 under Section 61, as is used to track RECs under Section 28 of Act 295, should
24 simplify the task of ensuring that RECs generated under the VGP programs are
25 properly assigned and retired and that RECs are not double-counted.

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1 Nevertheless, other certification and tracking systems, such as Green-e
2 certification offered by CRS, would also be an option. Insofar as the party
3 retiring the RECs is concerned, the Commission agrees that for most
4 participants it would be preferable for the utility to ensure that RECs are
5 properly tracked and retired. However, for some large commercial and
6 industrial participants, it may be advantageous to provide an option for the
7 customer to own and retire (*emphasis added*) any RECs generated under the
8 program.”

9 Staff is concerned that DTE has interpreted the Commission’s Order to mean that,
10 by transferring the RECs to the Customer, it is alleviated of all responsibility to ensure that
11 RECs are retired in the amount of the VGP being contracted. Staff does acknowledge PA
12 295, as amended by PA 235, removes VGP sales from the denominator of the renewable
13 portfolio requirement. However, Staff believes that this only occurs when RECs are retired
14 in an amount that covers the associated sales that the Customer has enrolled in for an
15 approved VGP program, ensuring that those sales are indeed served by renewable energy.
16 In accordance with MCL 460.1061, “the amount of electricity attributable to the customer
17 that will be renewable energy.” Further emphasized by the Commission’s Order in Case
18 No. U-18349, it specifically uses the phrase “own and retire.” Contrary to the Company’s
19 response in Staff Exhibit S-1.0, it is the Company’s renewable portfolio requirement and,
20 therefore, the Company’s responsibility to ensure that those RECs are properly retired to
21 cover sales served by VGP, prior to the VGP sales being removed from the compliance
22 calculation. One REC equals one MWh of renewable energy, with the REC representing
23 the renewable attributes of that energy being real and certified. Staff recommends that the
24 Commission not approve a VGP program that does not require RECs be retired prior to
25 being removed from the RPS compliance calculation. To the extent that such a program is
26 proposed as part of a Special Contract, Staff recommends that the Commission deny it. In

DIRECT TESTIMONY OF NAOMI J. SIMPSON
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1 addition, to the extent that such a program already exists, it should be addressed and
2 changed in the Company's next VGP filing.

3 Q. Does the Company's treatment of RECs described in Staff Exhibit S-1.0 have a potential
4 impact on Clean Energy Compliance?

5 A. Yes. Staff Exhibit S-1.1 confirms that the Company intends to count these same RECs
6 toward Clean Energy Plan compliance. The Commission has stated, in its December 18,
7 2026 Order in Case No. U-21867, that one REC may be retired to meet one 1 MWh of
8 clean energy for the purpose of meeting the Clean Energy Standard, MCL 460.1051.³ The
9 Clean Energy Standard, as defined in MCL 460.1051, does not exclude sales from
10 Voluntary Green Pricing and, therefore at the very least, those RECs generated by the
11 CCAA renewable resources would need to be retired on behalf of the Customer or
12 immediately upon transfer, by the Customer, to allow those MWh to count toward
13 compliance, and that the RPS compliance year and the CEP compliance year must align to
14 ensure that RECs are only used once.

15 Q. Please describe Staff's recommendations regarding its request to record a financial
16 compensation mechanism (FCM) associated with 300 MW of ZRCs paid by the Customer
17 as non-refundable income, as described pages 31 and 32 of DTE witness Foley's testimony.

18 A. Staff recommends that the Commission deny the Company's request. Through Staff audit,
19 the Company admitted that it did not consider this transaction to be a power purchase
20 agreement, as there is no actual purchase of power as part of this transaction. The
21 Company's response can be found in Staff Exhibit S-1.2. The Company also provided a

³ Commission's December 18, 2026 Order in Case No. U-21867, Exhibits C, D, E, & F.

DIRECT TESTIMONY OF NAOMI J. SIMPSON
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description of how it intends to record the FCM as non-refundable income in Staff Exhibit S-1.3. Therefore, Staff recommends that the FCM revenue be used to benefit all customers and be recorded as revenue that will offset the Company's future revenue deficiencies. Allowing the Company to collect an FCM that is not directed by statute creates an incentive for the Company to seek customers willing to pay an increased rate and ultimately charge large customers excessive rates for the sole benefit of its shareholders. Instead, the FCM related to the 300 MW of ZRCs should be passed through for the benefit of all ratepayers, including those customers on D11.

Q. Does Staff have any recommendations for reporting?

A. Yes. Staff recommends the Commission direct the Company to file a report consistent with the Commission's December 18, 2025 Order in Case No. U-21990, p. 42. Staff recommends the Commission direct the Company to file a quarterly report detailing the Customer's load profile for the previous quarter; the amount of renewable and storage that is operational under the CCAA as of the end of the quarter; the Customer's total demand for the preceding 12 months, compared to the expected contract capacity and minimum billing demand (MBD) and any changes to the Customer's credit rating, as well as associated impacts to credit or collateral terms; and an assessment of the financial state of the Customer. Then, on an annual basis, in any report filed on June 30, the Company should include information related to the realization of the affordability benefit. Staff recommends the first report be filed in this docket on June 30, 2027.

Q. Please provide a summary of Staff's recommendations for conditional approval contained in your testimony.

A. My testimony includes the following recommendations for conditional approval:

DIRECT TESTIMONY OF NAOMI J. SIMPSON
CASE NUMBER U-22058
PART II

1. A comparison of the resource requirements needed to comply with the renewable portfolio standard targets, both with and without the Company's large load customers' load and corresponding retail sales.
2. An analysis of options for recovery of any incremental costs of renewable portfolio standard compliance that may result in a surcharge, such that the surcharge is not collected on a per meter basis.
3. An analysis of equitable ways to recover the incremental costs of renewable portfolio standard compliance, which ensures that costs and benefits are appropriately distributed among rate classes.
4. In its next integrated resource plan (IRP) application and its initial clean energy plan (CEP) application (filed together), DTE Electric Company shall include a comparison of the resource requirements necessary to serve the Company's load and meet the renewable portfolio standard (RPS), clean energy standard (CES), and resource adequacy and reliability, both with and without the addition of the large load Customer's load and Special Contract resources.
5. Staff recommends that the Company prioritize the lowest cost resources to fill its IRP resource need first and then select resources to fulfill the CCAA, similar to its strategy for the Company's large load customer in Case No. U-21990.
6. Staff recommends that the RECs transferred to the Customer from the renewable resources contained in the CCAA contract, as part of the Company's Voluntary Green Pricing Program, be retired in the year that the Company is subtracting those VGP sales from its renewable portfolio requirement calculation.

DIRECT TESTIMONY OF NAOMI J. SIMPSON
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- 1 7. Staff recommends that the Commission deny the Company's request to record the
2 FCM associated with the 300 MW of ZRCs as non-refundable income.
- 3 8. Staff recommends quarterly and annual reporting as stated above.
- 4 Q. Does this conclude your testimony?
- 5 A. Yes, it does.

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of	)	
DTE ELECTRIC COMPANY	)	
for approval of special contracts and	)	Case No. U-22058
related relief.	)	
_____	)	

REBUTTAL TESTIMONY OF
NAOMI J. SIMPSON
MICHIGAN PUBLIC SERVICE COMMISSION

June 17, 2026

**REBUTTAL TESTIMONY OF NAOMI J. SIMPSON
CASE NUMBER U-22058**

1 Q. Are you the same Naomi J. Simpson that filed direct testimony in this proceeding?

2 A. Yes. I am.

3 Q. What is the purpose of your rebuttal testimony?

4 A. The purpose of my rebuttal testimony is to provide Michigan Public Service Commission
5 Staff's (Staff) position on certain recommendations in Laura S. Sherman's direct
6 testimony, who is responding on behalf of Michigan Energy Innovation Business Council,
7 Institute for Energy Innovation, Ecology Center, Environmental Law & Policy Center,
8 Union of Concerned Scientists, and Vote Solar (Collectively MEI/CEO).

9 Q. Are you sponsoring any exhibits?

10 A. No, I am not.

11 Q. What are the specific recommendations by MEI/CEO witness Sherman you are rebutting?

12 A. Staff has specific concerns about the appropriateness of the following of MEI/CEO witness
13 Sherman's recommendation about directing an ownership split of 50% third-party owned
14 projects and 50% Company-owned projects, including Build-Transfer Agreements (BTAs)
15 and self-build projects (MEI/CEO witness Sherman Direct Testimony, p. 8.).

16 Q. What are Staff's concerns with the 50% ownership split?

17 A. Staff has consistently opposed a 50% ownership split in all cases on the simple premise
18 that if the Competitive Procurement Guidelines are met, the most economic projects should
19 be selected. In such a case, and to the extent that a special contract resource is being paid
20 by a specific customer under a voluntary program, Staff does not have the same concerns
21 as it does for the selection of resources that serve all DTE (the Company) customers.
22 However, as stated by MEI/CEO witness Sherman on page 23 of her direct testimony, to
23 the extent that "the Customer terminates the CRO Special Contract, those resources would

**REBUTTAL TESTIMONY OF NAOMI J. SIMPSON
CASE NUMBER U-22058**

1 first be allocated to other customers in the VGP Program. If there is not sufficient demand
2 for the resources by other customers in the VGP Program, the resources would be allocated
3 to all ratepayers through the Renewable Energy Plan or Clean Energy Plan.” Under this
4 premise, Staff would recommend that no ownership split be determined to allow for the
5 Competitive Procurement Guidelines to ensure that the most economic projects could be
6 contracted. As an example, requiring a specific split in project ownership effectively
7 creates two separate Request for Proposals (RFPs). Rather than competing against all
8 proposals on price and value in a single solicitation, projects would compete only against
9 others within their ownership category. This limits direct competition or comparison across
10 all bids and can result in higher-cost projects being selected over lower-cost alternatives.
11 Consequently, there is no way to ensure that the selected portfolio represents the most
12 economic set of bids available. Predetermining the ownership split could ultimately result
13 in increased cost, regardless of whether the resources are owned by the utility or a third
14 party. Staff also acknowledges that it fully expects the Company to adhere to its Company-
15 owned project cost that was used to determine that any Company-owned or BTA project
16 was indeed the most cost effective. Staff will conduct reviews and audit Company-owned
17 project costs in the appropriate cost recovery cases.

18 Q. Does this conclude your testimony?

19 A. Yes, it does.

1 MR. SONNEVELDT: Thank you, your Honor.

2 Next, Staff would move to bind in the Direct Testimony of
3 David W. Isakson. He sponsored or filed direct testimony
4 that is Confidential. His testimony consists of 33
5 pages, including a cover page with 32 pages of questions
6 and answers. He also sponsored Exhibits S-3.0, S-3.1,
7 S-3.2, Confidential S-3.3, S-3.4, and S-3.5. He
8 sponsored no rebuttal testimony.

9 JUDGE STALEY: Thank you. Is there any
10 objection to the binding in of the Confidential prefiled
11 Direct Testimony of David W. Isakson or the admission of
12 Exhibits S-3.0, S-3.1, S-3.2, Confidential S-3.3, Exhibit
13 S-3.4, and Exhibit S-3.5?

14 Hearing none, the prefiled Confidential
15 Testimony, Direct Testimony of David W. Isakson is bound
16 into the record, and Exhibits S-3.0 through S-3.5 are
17 admitted into evidence, with S-3.3 being Confidential.

18 (Public Direct Testimony bound in.)

19 - - -

20 (Confidential Direct Testimony found on Page 988 of
21 the Confidential Record.)

22 - - -

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

Case No. U-22058

In the matter of the Application of
DTE ELECTRIC COMPANY
for Approval of Special Contracts
and for other relief.

QUALIFICATIONS AND DIRECT TESTIMONY OF

DAVID W. ISAKSON

MICHIGAN PUBLIC SERVICE COMMISSION

June 5, 2026

**QUALIFICATIONS AND DIRECT TESTIMONY OF
DAVID W. ISAKSON
U-22058**

1 Q. Please state your name, address, and current position.

2 A. My name is David W. Isakson (he/him/his). My business address is 7109 West Saginaw
3 Hwy, Lansing, Michigan 48917. I am currently employed by the Michigan Public Service
4 Commission (MPSC or Commission) in the Rates and Tariff Section of the Regulated
5 Energy Division as a Departmental Analyst.

6 Q. Would you briefly describe your educational background?

7 A. I earned a B.S. in economics from Central Michigan University in 2008. In 2011, I
8 completed an M.A. in economics at Central Michigan University.

9 Q. Have you attended any seminars or other training courses?

10 A. Yes. In August 2012, I completed the National Association of Regulatory Utility
11 Commissioners (NARUC) Annual Regulatory Studies Program held at Michigan State
12 University. I attended the AEIC Advanced Load Research Seminar in October 2012, and
13 the Electric Cost of Service Study and Electric Utility Pricing courses hosted by EUCI in
14 July 2019.

15 Q. How long have you been employed by the MPSC and what are your responsibilities in
16 your current position?

17 A. I have been employed by the MPSC since 2011. I participate in rate, tariff amendment,
18 reconciliation, integrated resource plan (IRP), special contract, *ex parte* tariff, and other
19 cases under the supervision of the Rates and Tariff manager. My work involves
20 performing electric rate design, gas rate design, and tariff analysis. My duties also
21 involve performing research in special topics such as rate benchmarking, load research,
22 demand response, and the economics of public utility regulation.

**QUALIFICATIONS AND DIRECT TESTIMONY OF
DAVID W. ISAKSON
U-22058**

1 Q. Have you previously presented testimony in cases before the MPSC?

2 A. Yes, I have presented testimony in the following cases:

3	<u>MPSC Case</u>	<u>Company</u>	<u>Work Description</u>
4	U-17437	DTE Electric Company	PLD Transition Plan
5	U-17643	Consumers Energy Company	Gas Rate Design
6	U-17761	DTE Electric Company	PLD Trans. Reconciliation
7	U-17767	DTE Electric Company	Electric Rate Design
8	U-17999	DTE Gas Company	Gas Cost of Service Study
9	U-18014	DTE Electric Company	Electric Rate Design
10	U-18124	Consumers Energy Company	Gas Cost of Service Study
11	U-18322	Consumers Energy Company	Electric Rate Design
12	U-18424	Consumers Energy Company	Gas Cost of Service Study
13	U-18999	DTE Gas Company	Gas Cost of Service Study
14	U-20102	Consumers Energy Company	Electric TCJA Credit A
15	U-20103	Consumers Energy Company	Gas TCJA Credit A
16	U-20134	Consumers Energy Company	Electric Rate Design
17	U-20165	Consumers Energy Company	IRP- Demand Response (DR)
18	U-20287	Consumers Energy Company	Gas TCJA Credit B
19	U-20286	Consumers Energy Company	Electric TCJA Credit B
20	U-20309	Consumers Energy Company	TCJA Calculation C
21	U-20322	Consumers Energy Company	Gas Cost of Service Study
22	U-20471	DTE Electric Company	IRP - DR
23	U-20479	SEMCO Energy Gas Company	ASP Revenue
24	U-20561	DTE Electric Company	Electric Rate Design
25	U-20642	DTE Gas Company	Gas DR
26	U-20650	Consumers Energy Company	Gas DR, Tariffs
27	U-20940	DTE Gas Company	R&D Expense
28	U-20963	Consumers Energy Company	Electric Rate Design
29	U-21080	Consumers Energy Company	DR Reconciliation
30	U-21148	Consumers Energy Company	Renewable Natural Gas
31	U-21224	Consumers Energy Company	Electric Rate Design
32	U-21297	DTE Electric Company	Electric Rate Design
33	U-21389	Consumers Energy Company	Electric Rate Design
34	U-21540	Michigan Gas Utilities Corporation	Gas Cost of Service Study
35	U-21534	DTE Electric Company	Electric Rate Design
36	U-21585	Consumers Energy Company	Electric Rate Design
37	U-21859	Consumers Energy Company	Large Load Tariff Amendment
38	U-21860	DTE Electric Company	Electric Rate Design
39	U-21918	Consumers Energy Company	IRM Reconciliation

40
41

**QUALIFICATIONS AND DIRECT TESTIMONY OF
DAVID W. ISAKSON
U-22058**

1 Q. What is the purpose of your testimony?

2 A. The purpose of my testimony is to present MPSC Staff's (Staff's) analysis of DTE
3 Electric Company's ("DTE" or "the Company") proposed Power Supply Agreement
4 ("PSA") and Clean Capacity Accelerator Agreement ("CCAA" and together with the PSA
5 "special contracts") to serve Google LLC ("Google" or "the Customer"). Specifically, I
6 will discuss the impact on and overall net benefit to customers, potential cost allocation
7 issues to address in the future, certain provisions of the special contracts, scenarios under
8 which impacts and net benefits may change, and Staff's recommendations related to those
9 topics.

10 Q. Are you sponsoring any exhibits?

11 A. Yes, I am sponsoring the following exhibits:

12 Exhibits:

13 Exhibit S-3.0 "Staff Customer Benefit"

14 Exhibit S-3.1 "Staff Cost of Service Study Analysis"

15 Exhibit S-3.2 "Staff Customer Choice Assumption Comparison"

16 Exhibit S-3.3 "Staff Scenario Analysis" CONFIDENTIAL

17 Exhibit S-3.4 "Audit Response DWI-2"

18 Exhibit S-3.5 "Discovery Response STDE-8.2"

19

20 Q. Did you use a large language model or any other generative artificial intelligence in any
21 capacity to prepare this testimony or sponsored exhibits?

22 A. No, I did not.

**QUALIFICATIONS AND DIRECT TESTIMONY OF
DAVID W. ISAKSON
U-22058**

Background

- 1
- 2 Q. Has the Commission previously considered the effect of large load customers (LLCs),
- 3 including data center customers, and their treatment under the regulated rate and tariff
- 4 authority of the Commission?
- 5 A. No. Beginning in 2025 with Case U-21859 the Commission approved a modified tariff
- 6 provision for Consumers Energy Company (Consumers) for serving customers with loads
- 7 of 100MW or more.¹ That tariff included several mechanisms meant to protect existing
- 8 customers and the utility from potential harms that may occur when serving LLCs, such
- 9 as the increased impact of LLCs leaving the utility's system before adequate cost
- 10 recovery. The Commission also approved an ex parte special contract case for DTE to
- 11 serve Green Chile Ventures LLC, a subsidiary of Oracle Corporation ("Oracle"), on
- 12 December 18, 2025 in Case No. U-21990. On-going proceedings related to serving LLCs
- 13 include Indiana Michigan Power's application to modify its Large Power Tariff, and
- 14 DTE's Large Load Provision tariff proposal, similar to the one approved for Consumers.
- 15 The Company was required by the Commission as part of its order approving the Oracle
- 16 special contracts to file a proposed large load tariff.²
- 17 Q. What does it mean for the Commission to approve service to customers on special
- 18 contracts?
- 19 A. A special contract is used to provide service to a customer under terms and conditions
- 20 other than what is found in a regulated utility's rates and tariffs. These special terms or

¹ November 6, 2025 Order in MPSC Case No. U-21859.

² December 18, 2025 Order in MPSC Case No. U-21990, p 45, paragraph H.

**QUALIFICATIONS AND DIRECT TESTIMONY OF
DAVID W. ISAKSON
U-22058**

1 conditions can include anything from special charges or discounts to unique methods of
2 revenue or cost sharing between customer and utility. For example, the Power Supply
3 Agreement in the instant case³ is a special contract because it differs from the standard
4 tariff for service on Rate D11, on which the Customer would normally take service. The
5 Company does not yet have a large load tariff comparable to Consumers, so the Customer
6 would otherwise take service on Rate D11 like any other primary customer at
7 transmission voltage level, but without any of the customer protections described by the
8 Company in the PSA or clean energy benefits from CCAA.

9 Q. How is your testimony organized?

10 A. I will address the following topics in my direct testimony:

- 11 1. The estimated sales and revenue impact on customers as a result of serving
12 Google's new load on the special contracts.
- 13 2. Potential cost allocation issues and when those issues should be addressed.
- 14 3. Specific terms of the special contract and how they relate to previous
15 Commission-approved mechanisms for serving LLCs and those proposed by the
16 Company in its tariff case.
- 17 4. An analysis of minimum bill revenue, collateral, termination payment, and
18 potential scenarios.⁴
- 19 5. Finally, I will provide Staff's recommendations for the Commission to consider

³ The term "instant case" refers to the case in which this testimony appears, so it is a shorthand to refer to Case No. U-22058. The terminology also avoids the ambiguous phrase "this case" when referring to any number of other proceedings before the Commission.

⁴ This section relies on confidential data provided by the Company and will contain redactions.

**QUALIFICATIONS AND DIRECT TESTIMONY OF
DAVID W. ISAKSON
U-22058**

1 when deciding whether or not to conditionally approve the special contracts.

2
3 **Customer Sales Revenue Impact**

4 Q. How did Staff analyze the Company's base sales benefit?

5 A. Staff audited the billing determinants and rates used by the Company to calculate the
6 annual revenue generated by the Customer. The resulting revenue was incorporated into
7 the Company's final Commission-approved cost of service study (COSS) from Case U-
8 21534 which was adjusted to include sales and revenue for the previous special contract
9 data center customer, Oracle. The Company relied on rates approved in Case U-21297
10 (i.e. present rates for Case U-21534), which were in effect beginning in December 2023.
11 Updating the Company's models to use currently approved rates, which went into effect
12 in March 2026, increases the overall base sales benefit from the Customer taking service
13 by about the same amount as the rate increase for transmission voltage level customers.
14 Staff found the increase in revenue from using the Company's most recently approved
15 rates did not have a significant impact on the outcome of the overall net customer benefit.
16 In order to easily compare Staff's review with the Company's filing, Staff did not update
17 the rates used to calculate revenues for inclusion in Company Exhibit A-20.⁵

18 Q. Please describe Staff Exhibit S-3.0.

19 A. Staff Exhibit S-3.0 largely matches Company Exhibit A-19, which presents the total net
20 benefit or cost of serving the Customer to all other customers. Staff found the base sales

⁵ For example, the overall revenue sufficiency when using rates approved in U-21860 was \$203.9M compared to a revenue sufficiency of \$201.5M when using rates approved in U-21297.

**QUALIFICATIONS AND DIRECT TESTIMONY OF
DAVID W. ISAKSON
U-22058**

1 benefit and cost assumptions made by the Company to be an adequate starting point for
2 Staff's initial analysis. Staff's audit confirmed that the values in Exhibit A-19 match the
3 Company's other exhibits. Staff's exhibit removes the escalation of base rate revenue
4 from line 2 and calculates the cumulative effect of the total net benefit to customers.

5 Q. Why did Staff remove the 1.5% escalation in rate revenue over the initial 20-year term of
6 the special contract?

7 A. Because typically rates increase after the Company files a rate case requesting a higher
8 revenue requirement as costs go up, as approved by the Commission. It is therefore not
9 reasonable to assume increasing revenues from the Customer without considering that
10 those revenues are actually increasing to offset new cost recovery. In fact, additional
11 revenue collected from Oracle via base D11 rates may put downward pressure on rates
12 prior to Google taking service, which means that general rate increases may not
13 necessarily be as certain as in the recent decade or so. Furthermore, Staff's analysis here
14 represents a lower-bound for the impact of new revenue provided by the Customer, so
15 that the Commission may have a fuller picture when it decides whether or not to approve
16 the special contracts.

17 Q. What is the impact of removing the 1.5% rate escalation over the term of the contract?

18 A. Without rate escalation the net benefit using the Company's other assumptions results in a
19 total net benefit of \$860.3M (this compares to \$1.697B as filed by the Company). Staff
20 does not argue that this scenario is likely. All else equal, it is more likely that the
21 Company files rate cases at some point during the contract term, particularly for at least
22 some of the years between 2035 and 2038 when the annual net benefit of the customer is

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negative. Rather than argue that a rate escalation is unreasonable, Staff instead presents the scenario where rates do not increase separately from all other utility costs over 20 years.

Q. Please describe Staff Exhibit S-3.1.

A. Exhibit S-3.1 relies on three COSSs provided by the Company: the final approved COSS from Case U-21534 without either LLC included, the COSS from Case U-21990 that includes only Oracle, and the COSS for the instant case that includes both Oracle⁶ and Google. Exhibit S-3.1 simply takes the difference between the results of the three studies and compares the impact of each LLC's new revenue. A summary of this comparison can be found on Table 1 below:

Table 1

Power Supply (\$000)	Oracle	Google	Total
Total Residential	\$ (114,601)	\$ (72,102)	\$ (186,703)
Total Commercial	(62,278)	(38,860)	(101,138)
Total Primary	(64,619)	(92,745)	(157,364)
Total Lighting	(753)	(451)	(1,204)
Total Production	\$ (242,251)	\$ (204,158)	\$ (446,408)

Distribution (\$000)	Oracle	Google	Total
Residential Secondary	\$ 5,156	\$ 4,668	\$ 9,823
Commercial Secondary	2,059	1,941	4,000
Primary	3,834	2,998	6,832
Subtransmission	2,572	73	2,645
Transmission	25,793	(7,266)	18,528
Lighting	316	215	531
Total Distribution	\$ 39,730	\$ 2,628	\$ 42,358

Total	\$ (202,521)	\$ (201,529)	\$ (404,050)

⁶ The impact and effect of Oracle's sales is not at issue in the instant case, and only included as a means to isolate the impact of Google's new service under the special contracts.

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1
2 This table shows what the revenue deficiency (sufficiency) would be in Case U-21534
3 with either or both LLCs in service.⁷ If the sales and revenue from the Customer were
4 added directly into the COSS from Case U-21534, then all customer classes (i.e.,
5 residential, commercial, primary, and lighting) would receive an overall decrease in
6 revenue requirement enough to completely negate the revenue deficiency resulting from
7 Case U-21534 and then some. Table 1 shows that the primary class would receive the
8 highest share of the revenue benefit of including the Customer. Intuitively, this makes
9 sense because the Customer would be part of the primary class and thus their revenue
10 would offset their own class's costs. The benefit to the primary class may be offset,
11 however, because the increased sales of demand and energy may cause more costs to be
12 allocated to the class as well.

13 Furthermore, the large reduction in revenue requirement for power supply
14 (\$204.1M from Google-only) is offset by a revenue requirement *increase* for distribution
15 (\$2.6M from Google, \$39.7M from Oracle). This analysis does not include any
16 exogenous cost increases for serving the LLCs, as such the different outcomes for power
17 supply and distribution are purely a result of the increased sales and revenue.

18 Q. How can the distribution revenue requirement increase when sales and revenue increase?

19 A. Answering this question will require more study by the Company, Staff, and intervenors,

⁷ Staff adjusted the final Commission-approved COSS for the Company's most recent case U-21860 in the same manner as the Company did to include the LLCs in the instant case but found no material difference. There were no significant changes to allocators or other COSS mechanisms between Cases U-21534 and U-21860 that would noticeably change the results of the analysis. In order to better compare with the Company's filing Staff also relied on U-21534 as the base case.

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1 but Staff identified several avenues by which a lopsided impact on revenue requirement
2 by function⁸ could result from simply inserting sales and revenue from LLCs into the
3 COSS. For example, one of the main drivers of the increase in revenue requirement for
4 distribution is the increase in income taxes that result from the increase in revenue
5 received by the Company. Higher income means a higher tax expense and therefore
6 higher revenue requirement. Some allocators in the COSS are based on sales (i.e.,
7 electricity sold to customers in terms of MW or MWh) or net income, which would be
8 affected by the new service to LLCs, and thus changes to those allocators could affect
9 how different customers' revenue requirements are impacted. The workpapers for Exhibit
10 S-3.1 contain more granular line-item differences between the base case COSS from U-
11 21534 and including both LLCs separately, and the change to distribution income tax
12 expense is but one of many.

13 Q. If there is an overall reduction to revenue requirement then why does it matter if there is
14 an increase to distribution revenue requirement? Aren't all customers still better off?

15 A. Not all customers would be better off with the base sales benefit if it were included in the
16 previously approved COSS as-is because choice customers only take distribution service
17 from the Company and thus do not pay power supply rates. Therefore, choice customers
18 would only receive the increase in revenue requirement and not the offsetting decrease to
19 power supply. If the COSS is not adjusted to account for the increase in distribution
20 revenue requirement then choice customers would be worse off, which may lead them to

⁸ Functionalization is the process in a COSS where costs are separated by *function* such as: production, transmission, distribution, customer service, and administrative and general. In this discussion I am referring to the impact of new revenues on the functions of power supply and distribution.

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1 consider a move back to taking power supply service from the Company. The
2 Commission should consider the impact of the Customer and LLCs on *all* customers.

3 Q. What effect does customer choice have on the revenue requirement impact of serving the
4 Customer and Oracle?

5 A. Customers may take service from an alternative electric supplier up to 10% of a utility's
6 annual retail sales.⁹ The Company assumed that because Oracle's new load increased the
7 overall system sales by 10,903,572 MWh then 10% of that increase would move to
8 choice.¹⁰ However, the Company did not make the same assumption for the increase of
9 7,884,000 MWh due to Google's new service. As I explain later in this testimony, the
10 effect of both LLCs' new revenue has implications on cost allocation that may complicate
11 other customers' decisions on whether to move to choice or take power supply service
12 from the Company. These new LLCs have not completed their full load ramp schedules
13 and therefore the cap for customer choice has not yet increased to its fullest extent.
14 Because we don't yet know how the addition of Google's new load will affect rates and
15 choice customers, Staff prepared Exhibit S-3.2 which shows the impact of choice sales on
16 the revenue sufficiency created by the new LLC sales under 3 scenarios. Column (a) of
17 Staff Exhibit S-3.2 shows the revenue sufficiency¹¹ by rate and class assuming that the
18 full 10% of increased sales for both LLCs moved to choice service, Column (b) assumes
19 the Company's base case that only Oracle's sales increase would move to choice, and
20 Column (c) assumes no customers would move to choice even when the cap is raised.

⁹ MCL 460.10a.

¹⁰ Staff Exhibit S-3.4

¹¹ Based on the COSS approved in U-21534.

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1 The total revenue sufficiency impact remains the same and distribution impacts by class
2 are unaffected because all customers, full service and choice, pay the same distribution
3 rates. For example, line 31 of Exhibit S-3.2 shows the total impact of both LLCs'
4 revenues on rates are \$186.4M, which matches the Company's finding on Exhibit A-20
5 (column h, line 20), so Staff's exhibit shows how that sales benefit falls among the
6 different rate classes.

7 This analysis shows the primary class receives more of the benefits of the LLCs'
8 sales as more primary class customers move to choice. For example, if the full 10% of
9 increased sales moves to choice, then the primary class would receive a \$178M revenue
10 sufficiency. Whereas if no customers moved to choice, the primary class would receive a
11 \$138M sufficiency. This has the opposite effect on the other classes, so more movement
12 to choice reduces the revenue sufficiency for residential customers. This occurrence
13 could also be described as: when customers move from full service to choice, the
14 remaining full service primary customers will be better off compared to all other
15 customers. As one can see from Staff Exhibit S-3.2, all customers would still see a
16 revenue sufficiency regardless of how many customers move or do not move to choice.

17 This analysis is intended to explore a range of possible outcomes as a result of serving the
18 Customer and other LLCs. This illustrates the fact that when the two LLCs complete their
19 full load ramp then the total impact on revenue requirement for other classes will also
20 depend on the choices made by other customers, which is beyond the control of either the
21 LLCs or the Company.

22

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Cost Allocation Issues and Timing

Q. Should the Commission make specific cost allocation decisions in the instant case?

A. Not directly, no. The purpose of the instant case is for the Commission to determine whether it is reasonable to approve service on the special contracts. Cost allocation issues associated with the Customer are more appropriately addressed in the Company's general rate cases along with all other utility costs and revenues. The purpose of my testimony on the subject is to highlight for the Commission that there will need to be a concerted effort to address any lingering effects on the COSS from including these new customers. The picture should become clearer once actual costs and revenues become available to analyze in a rate case. As it stands in the instant case, we must rely on cost estimates, but the total revenue generated by these customers is relatively straightforward. Furthermore, the Commission found in Case U-21990 that "approval of the special contracts, in and of itself, does not approve or require future approval of subsidization by existing customers, or cost recovery of stranded costs from existing customers."¹² The Commission should state the same in its order in the instant case.

Q. Does the base sales benefit, which relies on a previously-approved COSS, include any new costs to serve the Customer?

A. No, the analysis of increased sales and revenue only examines the impact of new revenue from the Customer, not new costs. Calculating the revenue is a relatively simple exercise of applying expected billing determinants, which are known due to the load ramp schedule, to approved rates and then including that revenue and sales in the COSS. New

¹² December 18, 2025 Order in MPSC Case No. U-21990, p 33.

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costs to serve the Customer are included in Company Exhibit A-19, which combines all the other expected costs and other miscellaneous benefits (i.e., offsetting PSCR and storage pull ahead) to arrive at a total net benefit or cost to other customers. The costs presented by the Company in Exhibit A-19 are not allocated among customer classes. The matter of allocating those costs will, again, be addressed as those costs become known and included in future general rate cases.

Q. What does Staff recommend regarding cost allocation?

A. Staff recommends that the Commission require the Company to file the six cost allocation and rate design studies that the Commission ordered the Company and Consumers to produce for any new LLC. Those six studies are as follows:

1. Under traditional ratemaking as exemplified by DTE Electric's current COSS from its most recent rate case order including the expected full contract capacity of any large load customer(s) on Rate D11;
2. Same as (1), but with the inclusion of a new large load customer rate class;
3. Same as (2), but using 12CP to allocate costs instead of 4CP where 4CP is currently being utilized;
4. Under traditional ratemaking utilizing the most recently approved COSS without the large load customer(s) in service;
5. **Utilizing a direct assignment of costs to a new large load customer rate class, including transmission, generation, and distribution costs;**
6. Utilizing a direct assignment of costs to the individual large load customer, again including transmission, generation, and distribution costs.¹³

Q. Does Staff have any alterations to the six cost allocation and rate design studies previously approved by the Commission for the Company to provide?

A. Yes. Regarding study number six "Utilizing a direct assignment of costs to the individual large load customer, again including transmission, generation, and distribution costs."

¹³ December 18, 2025 Order in Case No. U-21990, p 39-40, emphasis added.

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1 Staff recommends that the direct assignment should be to each large load customer
2 individually. This will account for any differences in cost burden or contract terms
3 between LLCs.

4 Q. What is the difference between requiring a COSS with LLCs on a new *rate* as opposed to
5 a new *rate class*?

6 A. Customer rate schedules, such as D-11, are part of a broader class of customers that share
7 a similar type of electric service. For example the primary class includes Rate D-11, D-
8 6.2, D-8, D-10, D-12, D-14, R-1.1, R-1.2, and R-20 which each apply to different types
9 of customers (e.g., Rate D-6.2 is only available to educational institutions) or offer
10 different pricing methods (e.g., Rate D-14 is a primary time-of-use rate). Within the
11 primary class and among those rate schedules customers are grouped by what voltage
12 level they take service on —primary, subtransmission, or transmission— and they are
13 charged different power supply and distribution rates depending on that voltage level.
14 Creating a new *rate* for LLCs but not creating a new *class* would mean that the LLC rate
15 would be within the primary class and be allocated costs just as any other customer in
16 that same class would. Further, because LLCs take service at the transmission level they
17 would be charged the same transmission level distribution charges as any other customer
18 in the same class, because distribution charges are universal within class.

19 The Company has four classes of customers: residential secondary, commercial
20 secondary, primary (which I just covered, and are sometimes called the “industrial”
21 class), and lighting. The COSS assigns revenue requirement to each class separately,
22 though sometimes it does so directly to a particular rate schedule. Revenue requirement

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1 assignment also depends on whether it is for power supply or distribution. For example,
2 the COSS produces separate power supply revenue requirements for Rate D-2, residential
3 space heating, and D1.11/other. "D1.11/other" includes the standard residential rate
4 D1.11 and a number of other residential rate schedules, so that power supply revenue
5 requirement is further split based on each individual rate's present revenue and then
6 applied.

7 The COSS only produces one distribution revenue requirement for the entire
8 class, except for the primary class which is split by voltage level. This is all by design,
9 because customers in the same class or voltage level use the distribution system in the
10 same way, whereas they may cause power supply costs differently. Just because the
11 COSS exists in its current configuration today, does not mean that it always did and
12 cannot change.

13 Creating a new *class* for large load customers would further separate them from
14 all other customers. This may be appropriate because as we see from the special contracts
15 in the instant case LLCs can impact cost allocation more significantly than other
16 customers (e.g., the aforementioned effect of their revenue on income taxes). A new class
17 for LLCs would also require that those customers be allocated their own distribution
18 revenue requirement, which likely would look quite different than other customers. For
19 example, the Customer in the instant case will pay for its own substation and contribute
20 up to \$50M towards its distribution system costs. This means that a new distribution rate
21 for Google could be effectively \$0.00, depending on how other general shared costs are
22 allocated to the Customer. Continuing this hypothetical: if the Customer pays zero dollars

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1 in base rates for distribution, that means they would also not contribute to embedded
2 distribution costs for any other class. In the future the Commission may find that it is
3 appropriate to create a new class for LLCs, but it would be wise to compare that method
4 of ratemaking against other feasible options at a later date.

5 Once again, Staff is not advocating in the instant case to engage in any cost
6 allocation or recommending any particular COSS adjustments, but rather requests that the
7 Commission require the Company provide the six different COSSs and rate designs in its
8 next rate case so that the Commission may make a judgement on how to create fair rates
9 for *all* customers.

10 Staff also recommends that the Commission require the Company to provide all
11 the data necessary to allow Staff and intervenors to recreate the six COSS proposals with
12 formulas intact, as well as track any costs that may be directly tied to the Customer so
13 that it is possible to determine the effect of directly assigning costs to either the Customer
14 or a potential new LLC class.

Contract Terms

16
17 Q. How do the terms of the special contracts in the instant case differ from those in Case U-
18 22061?

19 A. The terms of the Company's proposed Large Load Provision tariff in Case U-22061 are
20 largely present in the contracts considered in the instant case. For example, the minimum
21 billing demand of 80%, collateral may be provided via letter of credit or parent company
22 guarantee, minimum notice of discontinuance of 2 years, [REDACTED] all

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1 match the Company's proposed tariff. The main deviations are in contract term (20 years
2 for the special contracts instead of the minimum 15), collateral amount (discussed
3 below), contribution in aid of construction (CIAC), and virtually all the components of
4 the CCAA. Regarding CIAC, the Customer agrees to pay up to \$50M toward
5 infrastructure upgrades to serve the Customer, whereas the Company's LLP sets this
6 amount at the cost of the infrastructure needed for grid interconnection less an allowance
7 of 2-years-worth of distribution revenue. Under current rates set in Case U-21860, 2
8 years of distribution revenue for the Customer would create a CIAC allowance of about
9 \$30M. As described by the Company, under the current tariffs the Customer's CIAC
10 allowance would be approximately \$550M.¹⁴

11 Q. What does Staff recommend regarding the Customer's line extension agreement and
12 CIAC allowance?

13 A. Staff recommends that if the Commission approves the proposed tariff in Case U-22061
14 with a CIAC provision, then that same standard should be applied to the Customer for
15 costs beyond the \$50M identified in the line extension agreement. For example, if
16 infrastructure costs exceed \$50M by less than 2-years of distribution revenue then those
17 costs should be included for recovery in future rate cases, but the Customer should be
18 responsible for any costs over the CIAC allowance approved for the LLP.

19 Q. How do the terms of the special contracts in the instant case and Case U-22061 materially
20 compare to the LLP approved for Consumers in Case No. U-21859 in November 2025?

21 A. First, the termination payment, called the "exit fee" in the Consumers tariff, is similar:

¹⁴ Direct Testimony of Company witness Steven N. Benyard, p 6-7.

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1 equal to the remaining minimum bills for up to 15 years with a minimum termination
2 payment equal to 2 years of minimum bill revenue for the Customer. The exit fee for the
3 Consumers tariff is equal to the customers minimum bill for the remainder of the
4 contract, which is also a minimum of 15 years. The termination fee in DTE's PSA is
5 basically an extended version of the exit fee due to the contract lasting longer than 15
6 years. Second, the collateral amount under Consumers' tariff is equal to half of the exit
7 fee, [REDACTED]

8 [REDACTED]

9 [REDACTED]

10 [REDACTED]

11 [REDACTED]

12 [REDACTED]

13 [REDACTED]

14 [REDACTED]

15 [REDACTED]

16 [REDACTED]

17 [REDACTED]

18 [REDACTED]

19 [REDACTED] Third, the method of

20 providing said collateral differs from Consumers' tariff because the PSA allows the

21 customer to provide collateral via a parent guaranty, a letter of credit, or a combination of

22 the two. The Consumers tariff requires a letter of credit or cash for the collateral

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1 requirement, but also allows Consumers to require a different amount or form of
2 collateral pursuant to Commission review and approval. Essentially, DTE's request for
3 approval of the PSA is a proposal for a different collateral requirement and form, which is
4 allowable on the Consumers tariff established in U-21859. The PSA requires a letter of
5 credit depending on the parent company's credit rating, so there is a mechanism by which
6 a more secure form of collateral may be required if needed if the credit rating of the
7 parent company changes following execution of the special contracts.

8 Q. Has the Commission previously addressed the burden of risk involved if a LLC's
9 collateral falls short?

10 A. The Commission already cautioned the Company that in the event that an LLC's
11 collateral is not sufficient to cover remaining financial exposure caused by an LLC's exit
12 from service, that the Company would be responsible for unrecovered costs. In Case U-
13 21990, when conditionally approving the special contracts to serve Oracle, the
14 Commission included the following in its order:

15 "In addition, in the event of a failure to pay the [minimum billing demand] under the
16 PSA, or in the event of a termination, default, or other event whereby DTE Electric is
17 required to draw on the letter of credit or parental guaranty, if the company determines
18 that the specified collateral is not sufficient to cover the full amount of the remaining
19 financial exposure associated with the [special contracts] (minus the value to customers),
20 the Commission specifically cautions DTE Electric that any unrecovered costs shall not
21 be borne by ratepayers and that DTE Electric bears responsibility for any remaining
22 liability. All risk associated with the sufficiency of the collateral shall be borne by DTE
23 Electric."¹⁵
24

25 Staff recommends that the Commission make the same determination in the instant case.

¹⁵ December 18, 2025 Order in MPSC Case No. U-21990, p 41.

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1 The Company, as required by the Commission, filed a letter in the docket for Case U-
2 21990 accepting the conditions set forth by the Commission, including the quoted
3 paragraph above. The affordability backstop terms of the PSA enable the Company to
4 recover any related costs denied by the Commission from the Customer.¹⁶ In other words,
5 the affordability backstop not only insulates other customers, which is a priority shared
6 by the Commission and Staff, but also protects the Company from potential detrimental
7 effects resulting from serving the Customer. As the Commission found in Case U-21990,
8 and it should again find in the instant case, that approval of the special contracts is
9 conditioned “on the requirement that, at the very least, all current and future costs caused
10 by the Customer shall be covered by the Customer or by DTE Electric and not existing
11 customers.”¹⁷ This statement working in tandem with the affordability backstop should
12 prevent adverse outcomes for existing customers.

13
14 **Minimum Bill, Collateral, Termination Payment, and Scenario Analysis**

15 Q. Does Staff’s analysis here of minimum bill, collateral, and termination payment include
16 the effects of the CCAA?

17 A. No, staff did not include the termination payment for the CCAA in this analysis. Staff
18 understands that the CCAA may not be terminated by the Customer unless the Customer
19 defaults, and even then the Customer is still obligated to pay the termination payment for
20 the CCAA.

¹⁶ Direct Testimony of Company witness Neal T. Foley, p 19-20.

¹⁷ December 18, 2025 Order in MPSC Case No. U-21990, p 33.

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1 Q. Please describe Staff Exhibit S-3.3.

2 A. The first 22 lines of Staff Exhibit S-3.3 match Staff Exhibit S-3.0, which in turn mostly
3 replicates Company Exhibit A-19, which presents the total net benefit or cost of serving
4 the Customer to all other customers. Exhibit S-3.3 differs from Exhibit S-3.0 in that it
5 compares minimum bill revenue to the termination fee and collateral obligation and also
6 includes two possible scenarios: one in which the Customer takes service initially at the
7 full contracted capacity but then pays minimum bills for the remainder of the contract
8 term; and a potential “worst case scenario” that I will describe later.

9 Q. What is the minimum monthly charge identified by the Company?

10 A. Company witness Foley testified that based on D11 rates approved in the Company’s
11 latest rate case, U-21860, he expects minimum monthly bills to equal \$165.1M per
12 year.¹⁸ There is a slight mismatch between the rates starting point because the example
13 given in the PSA relies on the most recently approved rates, where the preceding data
14 from Exhibit S-3.0 and A-19 (lines 1-16) rely on rates approved in U-21297 and then
15 included in U-21534. As discussed previously, there is not significant impact of relying
16 on rates from different recent cases. Lines 24-25 of Exhibit S-3.3 calculate annual
17 minimum bill revenue throughout the 20 year contract period as well as the cumulative
18 amount of minimum revenue over that time. The termination payment and collateral
19 amounts by year are also included in the exhibit. That data comes from the redacted
20 version of the PSA and is used to evaluate both scenarios.

21 Q. How did Staff determine revenue and costs for the scenario where the Customer only

¹⁸ Direct Testimony of Company witness Neal Foley, p 15, lines 1-2.

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1 pays its minimum bills throughout the contract period?

2 A. Staff escalated the minimum bill revenue by 1.5% over the contact term (line 25), and
3 then found the cumulative effective of minimum bill revenue. Staff re-assumes the rate
4 escalation because this scenario is meant as a possible outcome and not necessarily the
5 other end of a spectrum of possibilities. In other words Staff is not attempting to change
6 too many variables for the minimum bill scenario compared to the Company's base case
7 with the Customer. Next, Staff isolated the net transmission cost by year by finding the
8 difference between Company Exhibit A-9, line 30 and Exhibit A-7, line 30, which is the
9 difference in transmission cost between the base case and case with the Customer. If the
10 Customer only pays its minimum bill, then it will not contribute to net PSCR benefits
11 because PSCR is an energy charge. In this scenario the Company would still have to pay
12 the marginal transmission costs to ITC, so it was necessary to separate those costs from
13 the overall PSCR benefit calculated in Company Exhibit A-13. Finally, Staff calculated
14 the net impact of minimum bill revenues, transmission costs, and other non-fuel and
15 purchase power O&M (line 6) to arrive at the annual and cumulative net impact on
16 customers for this scenario.

17 Q. Why are the costs for the CCGT, CCS, and benefits of the storage pull-ahead not included
18 in the costs and benefits for the minimum bill scenario?

19 A. For this scenario Staff assumes that the Customer completes its ramp schedule but never
20 pays beyond its minimum bill. This means that the Company never has the need to build
21 the new generation plant or accelerate storage to serve the customer, and also will not
22 have to purchase power to serve the customer. Transmission costs are still included

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1 because if the Customer completed its load ramp then it would still have needed
2 transmission capacity to begin service. Because it excludes the simulated CCGT, CCS,
3 storage, and also any benefits and costs associated with purchased power via the PSCR
4 this scenario represents how much the minimum bill covers the non-production cost
5 burden.

6 Q. What are Staff's findings from the minimum bill scenario?

7 A. This scenario shows that the minimum bill will cover non-production costs to serve the
8 Customer. Line 32 of Staff Exhibit S-3.3 shows how much the minimum bill will cover
9 those costs in percentage. For example, in 2035 the minimum bill will be 116.64% of
10 non-production costs, which is the lowest value for minimum bill coverage over the term.
11 Because the termination payment is made up of future minimum bill revenue one can
12 conclude that the termination payment also will cover non-production costs over the
13 contract term. An easy way to test that the termination payment will pay for non-
14 production costs is to compare the total non-production costs of \$2.476B¹⁹ to the
15 termination payment beginning with the full ramp period in 2028, which is also
16 \$2.476B²⁰.

17 Another insight to take away from this scenario is how the impact of the CCGT
18 and CCS are the largest cost drivers for serving the Customer. This is unsurprising
19 because the Company explained that the Customer will pay for up to \$50M in distribution
20 costs, which is above the Company's estimated cost for infrastructure enhancement

¹⁹ Exhibit S-3.0, line 27, column x.

²⁰ Exhibit S-3.0, line 34, column b.

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1 needed to serve the Customer.²¹ If distribution costs are expected to have little to no
2 impact on other customers and the minimum bill is sufficient to pay for transmission and
3 other non-production costs, then the only remaining costs to cover are production.

4 While not included in this scenario, the storage pull-ahead benefit would offset
5 total production costs somewhat.

6 This is a bit of a unique and unlikely scenario because the Customer would be
7 better off paying the termination fee instead of continuing to pay the minimum bill
8 indefinitely if it never expected to return to the full load ramp. For example, the
9 cumulative value of 20 years of minimum bills is about \$3.6B (Exhibit S-3.0, line 25,
10 column v), but paying the termination payment would save on future minimum bills
11 because those minimum bills and future termination payments will track any increases in
12 base rates. Also, the Company would likely renegotiate the special contracts if the
13 Customer's load ramp schedule changed that drastically.

14 If the Customer pays its minimum billing demand but also uses any amount of
15 energy, then the additional revenues that would flow through the PSCR and other energy
16 charges would also provide additional customer benefit.²²

17 Q. How does the collateral amount compare to termination payments in the minimum bill
18 scenario?

19 A. Lines 41 and 42 of Exhibit S-3.3 show that the collateral amount for the first 5 years of
20 the contract following completion of the load ramp is less than the termination payment.

²¹ Direct Testimony of Company Witness Beynard, p 6, line 19-p 7, line 3.

²² For example, if the customer has 500MW of load and a 90% load factor they would still be charged as if demand was 800MW, and energy sales would create more revenue than the minimum bill otherwise would.

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1 As previously discussed, the Commission has previously found that the Company is
2 responsible for any shortfall if the collateral is not sufficient to recoup costs.²³

3 Q. Why did Staff include a worst case scenario in its analysis?

4 A. The Company's filing and exhibits represent the best version of serving the Customer if
5 the Customer follows the committed ramp schedule and pay bills in full and on time.
6 Staff has shown two scenarios where those benefits are less than this ideal—with no rate
7 escalation and with the Customer only paying minimum bills— and in both of these
8 scenarios it is likely that there would still be a net benefit to other customers. Examining
9 a worst case scenario will illuminate gaps in coverage so that the Commission can
10 prepare for potential negative outcomes. Staff reiterates here that the Commission has
11 made it clear that it does not intend to place any burden on other customers for any
12 deficiencies resulting from the operation of or service to LLCs or the Company's special
13 contracts to serve them, and that the Commission will still need to consider cost
14 allocation questions regarding LLCs, including the Customer. Also, it's important to note
15 that the Company's affordability backstop will help mitigate a burden placed on the
16 Company should this worst case scenario come to fruition.

17 Q. Please describe Staff's hypothetical worst case scenario.

18 A. As explained earlier, a major driver of costs is the proxy CCGT and CCS. Staff's worst
19 case scenario is one where the Customer's load necessitates building a new CCGT and
20 CCS but then that load and thus the associated marginal revenue disappears due to the
21 Customer's early exit from service; like cancelling a party after the host already bought

²³ December 18, 2025 Order in MPSC Case No. U-21990, p 41.

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the cake. The scenario assumes that the customer takes service according to its ramp schedule through 2032, and the Commission authorizes the new CCGT/CCS resource in the Company's appropriate integrated resource plan (IRP). Then, beginning in 2033 the Customer reverts to only paying minimum bills for the remainder of the contract. The details of this scenario are displayed by year in Staff Exhibit S-3.3 on lines 36-40. In 2033 the total remaining cost obligation for all cost is \$7.5B (line 38, column [g]) and the total cumulative net benefits of full bill payment in prior years plus the minimum bill for 2033 plus the termination payment to cover remaining minimum bills beyond 2033 is [REDACTED] (line 39, column [g]). This produces a net cost of [REDACTED] in 2033, which [REDACTED]

Removing most of the benefits produced via PSCR (line 4) and a portion of the sales benefit (line 2) but retaining the net effect of the new CCGT, CCS, and storage pull-ahead (lines 8, 10, and 12) will approximate the results of Staff's worst case scenario. Note that if the Customer only pays minimum bills and does not use capacity or energy from the CCGT then the Company may still recoup some revenue by selling capacity on the market or to other customers if capacity need increases over time.

Q. How does collateral factor into the worst case scenario?

A. [REDACTED]

²⁴ Please note that the values on line 40 are the total differences if the Customer made the termination payment at the end of any particular year, so they are already cumulative. For example, [REDACTED].

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1 [REDACTED]

2 [REDACTED]

3 [REDACTED]

4 [REDACTED]

5 [REDACTED]

6 [REDACTED]

7 [REDACTED]

8 [REDACTED]

9 [REDACTED] The

10 Commission previously cautioned the Company that:

11 “[I]n the event of a failure to pay the [minimum billing demand] under the PSA, or in the

12 event of a termination, default, or other event whereby DTE Electric is required to draw

13 on the letter of credit or parental guaranty, if the company determines that the specified

14 collateral is not sufficient to cover the full amount of the remaining financial exposure

15 associated with the [special contracts] (minus the value to customers), the Commission

16 specifically cautions DTE Electric that any unrecovered costs shall not be borne by

17 ratepayers and that DTE Electric bears responsibility for any remaining liability. All risk

18 associated with the sufficiency of the collateral shall be borne by DTE Electric.”²⁶

19

20 Staff recommends that the Commission make the same finding in the instant case.

21 Q. If the Commission approves the special contracts how does Staff recommend the

22 Commission address potential negative outcomes like the worst case scenario?

23 A. The worst case scenario is simply a possibility, and there is still much to be determined

24 for serving the Customer. The Company’s next IRP may result in a different resource mix

²⁵ Staff Exhibit S-3.3, line 41, column (g).

²⁶ December 18, 2025 Order in MPSC Case No. U-21990, p 41.

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1 than the one contemplated in the instant case, along with commensurate differences in
2 costs or changes to the timing of the need for new capacity. Service to other LLCs may
3 also change the landscape of costs and benefits resulting from service to the Customer.
4 For example, if the Company's current LLC, Oracle, exits service then it may create a
5 capacity sufficiency and thus negate any need for new capacity resources to serve the
6 Customer.

7 In the Company's next and subsequent IRPs, the Commission should consider
8 how to eventually assign production costs to the Customer, or to the Customers' rate class
9 if it is separated, so that any marginal cost of new capacity resources will not be passed
10 on to other customers unfairly. Costs are not allocated nor is revenue collected via IRP
11 proceedings, but the Commission will have more information on the Company's
12 generation resource mix after it issues decisions in the case. The Commission may be
13 able to identify costs specific enough to the Customer to be able to use in future rate
14 cases if Staff's worst case scenario comes to be. In other words, the Commission could
15 determine, using data from the IRP, what an adjustment to future revenue requirements
16 would be in the event that the Customer or any other LLC leave service before the end of
17 their special contract. Much like with the cost allocation issues previously discussed in
18 my testimony it may be more prudent to address the issue of power supply cost
19 responsibility when and if it arises in future proceedings.

20 Q. Can the Commission re-open the instant case if any of its assumptions change or when
21 actual costs to serve and revenues collected from the Customer become known?

22 A. Yes. The Commission may wish to re-examine the termination payment and collateral

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1 amount following the first IRP where new capacity resources are needed to serve the
2 Customer, when costs should be more well known than the proxy included in the instant
3 case. In the order in Case U-21990, when describing the Commission's ability to return to
4 the case approving the Company's special contracts with Oracle, the Commission averred
5 that it "retains jurisdiction of this matter and reserves the authority to reopen this case at
6 any time and/or issue an order to show cause if DTE Electric's claimed affordability
7 benefit fails to materialize or vanishes or costs associated with serving the Customer are
8 expected to fall upon existing customers."²⁷ The Commission should repeat this
9 statement in its order in the instant case. As the Commission has repeated, the burden of
10 lost load from LLCs and the associated cost burden should not fall on other customers
11 and instead on the Company.²⁸ As such, the collateral amount and termination payment
12 should be re-examined within three years of the load ramp completion date. A periodic
13 review of the affordability benefit should be made in future rate cases and require the
14 Company to confirm that the special contracts are contingent on the Customer's rate
15 revenue and special contracts will cover the cost to serve the customer including
16 generation, transmission, distribution, and other costs.

17 According to the PSA, the Customer may take service on a new rate approved by
18 the Commission 2 years after the load ramp completion date, so it is possible that in the
19 future the minimum bill will reflect a new rate on which the Customer takes service. In
20 that case, the Commission must ensure that other customers are still protected from any

²⁷ December 18, 2025 Order in MPSC Case No. U-21990, p 43.

²⁸ November 6, 2025 Order in MPSC Case No. U-21859, p 125, paragraph D. December 18, 2025 Order in MPSC Case No. U-21990, p 32, p 40, and p 43, paragraph B.

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1 potential harms related to serving the Customer on a new rate and thus potentially
2 different minimum bill and termination payment.

3 Staff has no reason to believe that the Commission would shift any cost burden
4 from serving the Customer on to other customers, which means that the Company is most
5 at risk from any negative effects of the Customer leaving service at an inopportune time.
6 The affordability backstop will help the Company to recover any costs that may be
7 denied by the Commission, and if the Company determined that a parental guarantee is
8 adequate to protect its shareholders from that negative externality, then the Commission
9 should continue to place the burden on the Company.

10
11 **Recommendations Summary**

12 Q. Please summarize your recommendations.

13 A. Staff's recommendations are as follows:

- 14 • Issues of cost allocation should be addressed in future rate case proceedings.
15 When considering cost allocation the Commission should consider effects on full-
16 service and choice customers.
- 17 • The Commission should continue to require the Company to submit the six cost
18 of service studies required in Cases U-21589 and U-21990 in future proceedings,
19 including the alteration proposed by Staff concerning study number 6.
- 20 • The Commission should require the Company to track any costs that may be
21 directly tied to the Customer so that it is possible to determine the effect of
22 directly assigning costs to either the Customer or a potential new large load

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1 customer class.

- 2 • If a CIAC allowance is approved in Case U-22061, then it should be applied to
- 3 the Customer for any costs in excess of the line extension agreement.
- 4 • The Commission should again find that it retains authority to re-open the instant
- 5 case at any time or issue a show-cause if DTE Electric's claimed affordability
- 6 benefit fails to materialize or vanishes or costs associated with serving the
- 7 Customer are expected to fall upon existing customers..
- 8 • The Commission should require the Company to submit a letter to the docket
- 9 explicitly accepting all conditions deemed by the Commission as necessary for
- 10 approval of the special contracts within 15 days of the final order in the instant
- 11 case.

12 Q. Does this conclude your direct testimony?

13 A. Yes, it does.

1 MR. SONNEVELDT: Thank you, your Honor.

2 Next, Staff moves to bind in the Direct Testimony of
3 Katie J. Smith. Ms. Smith's direct testimony consists of
4 seven pages, including a cover page, with six pages of
5 question and answers. She also sponsors Exhibit S-2.0.
6 She filed no rebuttal testimony.

7 JUDGE STALEY: Thank you. Is there any
8 objection to the binding in of the prefiled Direct
9 Testimony of Katie J. Smith, or the admission of Exhibit
10 S-2.0?

11 Hearing none, the prefiled Direct
12 Testimony of Katie J. Smith is bound into the record, and
13 Exhibit S-2.0 is admitted into evidence.

14 (Direct Testimony bound in.)

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STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of	)	
DTE ELECTRIC COMPANY	)	
for approval of special contracts and	)	Case No. U-22058
related relief.	)	
_____	)	

QUALIFICATIONS AND DIRECT TESTIMONY OF
KATIE J. SMITH
MICHIGAN PUBLIC SERVICE COMMISSION

June 5, 2026

QUALIFICATIONS OF KATIE J. SMITH
CASE NUMBER U-22058
PART I

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

2 A. My name is Katie J. Smith and my business address is 7109 W. Saginaw
3 Highway, Lansing, MI 48917. I am employed by the Michigan Public Service
4 Commission (MPSC or Commission) as an Economic Specialist in the Energy
5 Optimization (EO) Section of the Energy Resources Division.

6 Q. Please describe your educational background.

7 A. I earned a dual Bachelor's degree in Finance and Economics from Lake Superior
8 State University.

9 Q. What is your work experience?

10 A. I worked for the Eastern Upper Peninsula Intermediate School District from 2006
11 to 2009, where I conducted data analysis and data processing of the Michigan
12 Educational Assessment Program (MEAP), as well as with several other
13 standardized tests. In August of 2009, I began employment with the MPSC as an
14 Economic Analyst working in the Energy Efficiency Section, currently the EO
15 Section. In June of 2018, I accepted the position of Economic Specialist in the
16 Resource Adequacy & Retail Choice (RARC) Section within the MPSC. In
17 February of 2020, I transferred back to the EO Section.

18 Q. What does your work at the MPSC consist of and what training have you completed
19 related to that work?

20 A. I serve at the Commission as an Economic Specialist working in the EO Section.
21 Public Act (PA) 295 (the Act), amended by PA 342 of 2016 and amended again by
22 PA 229 of 2023, requires regulated electric and natural gas utility providers to file
23 energy waste reduction (EWR or energy efficiency) plans and annual EWR

QUALIFICATIONS OF KATIE J. SMITH**CASE NUMBER U-22058****PART I**

reconciliations. My position in the EO Section includes assessing the reasonableness and feasibility of the utility EWR plans and reconciliations. The amended Act now allows for efficient electrification (EFEL) plans, which I also have oversight over. In addition, I work on the demand response (DR) team to assess DR programs proposed and implemented by utility providers. I am also the MPSC Staff (Staff) lead for EWR, DR, and EFEL potential studies.

In September of 2009, I attended the Building Financial Institute's Building Analyst Training. This was a comprehensive home energy assessment with coursework in building envelope evaluation, thermal and pressure boundaries, air sealing, and building airflow standards and calculations. Furthermore, I annually attend the National Association of Regulatory Utility Commissioners (NARUC) Regulatory Studies Program when programs and subject matter are presented that relate specifically to my duties. I have also traveled to conferences and trainings that were provided nationally on the subjects of DR, forecasting, and EWR.

Q. Have you previously filed testimony in proceedings before the Commission?

A. Yes. I have provided testimony in the following cases:

<u>Case No.</u>	<u>Description</u>	<u>Case No.</u>	<u>Description</u>
U-16180	Revenue Decoupling	U-16289	EO Plan
U-16358	EO Plan Financial Incentive	U-16169	Revenue Decoupling
U-16472	Revenue Decoupling	U-16566	Revenue Decoupling
U-16670	EO Plan Surcharge Clarification	U-16568	Revenue Decoupling
U-16794	Revenue Decoupling	U-16730	EO Plan
U-16855	Revenue Decoupling	U-16999	Revenue Decoupling
U-17603	EO Plan Revenue Decoupling	U-17771	EWR Plan

QUALIFICATIONS OF KATIE J. SMITH**CASE NUMBER U-22058****PART I**

1	U-18270	EWR Plan	U-18333	EWR Reconciliation
2	U-18370	Revenue Decoupling	U-18419	Demand Response
3	U-18424	Revenue Decoupling	U-18999	Revenue Decoupling
4	U-20028	EWR Credits/Financial Incentive	U-20165	Demand Response
5	U-20164	Demand Response	U-20591	Demand Response
6	U-20563	Demand Response	U-20373	EWR Plan Amend
7	U-20702	EWR Plan Reconciliation	U-20881	EWR Plan
8	U-20876	EWR Plan	U-20877	EWR Plan
9	U-20879	EWR Plan	U-20875	EWR Plan
10	U-21081	Integrated Resource Plan	U-21090	IRP
11	U-21189	Integrated Resource Plan	U-21053	EWR PSCR
12	U- 21654	EU Framework	U-21809	IRP
13	U-21684	EO Plan		

DIRECT TESTIMONY OF KATIE J. SMITH
CASE NUMBER U-22058
PART II

1 Q. What is the purpose of your testimony?

2 A. The purpose of my testimony is to provide Staff's recommendation for Energy
3 Waste Reduction (EWR) related to DTE's (the Company) Special Contract.

4 Q. Are you sponsoring any exhibits?

5 A. Yes, I am sponsoring Staff Exhibit S-2.0, Discovery Response.

6 Q. Was this exhibit prepared by you or under your direction?

7 A. Yes.

8 Q. Is the Company requesting anything related to EWR for this case?

9 A. No, however the Company does discuss that Google LLC (the Customer) is
10 planning to self-direct its legislative EWR goals and Staff discusses
11 recommendations related to that in this direct testimony.

12 Q. Will the Customer listed in the Company's Special Contract be required to
13 participate in the Company's EWR plan?

14 A. Yes, the Customer will either be required to pay the Company's EWR surcharges
15 as part of its rates or the Customer can self-direct its EWR program. The
16 Customer will still be required to pay a surcharge based on their obligation to the
17 low-income programs of the Company's EWR plan if it chooses to self-direct its
18 EWR plan.

19 Q. Has the Company stated whether the Customer will self-direct?

20 A. Yes, Company witness N.T. Foley states in direct testimony that the Customer
21 intends to self-direct their EWR goals.

22 Q. Has the Company made the Customer aware of the requirements of self-directing?

DIRECT TESTIMONY OF KATIE J. SMITH
CASE NUMBER U-22058
PART II

1 A. Yes, in the Staff’s discovery request, as shown in Staff Exhibit S-2.0, the
 2 Customer’s commitment related to a self-directed energy waste reduction plan is
 3 governed by Section 9.4 of the Purchase-Sale Agreement (PSA), which states:
 4 “Customer agrees to reasonably cooperate with Company to pursue the energy
 5 waste reduction standards set forth in Michigan Public Act 295 of 2008, MCL
 6 460.1001 et seq. and to participate in and comply with the self-directed energy
 7 waste reduction plan requirements set forth in MCL 460.1093.”

8 As such, the Customer has agreed to comply with Michigan’s self-
 9 directed energy waste reduction plans, as codified in MCL 460.1093.

10 Q. Does Staff have any recommendations for the Company when cooperating with
 11 the Customer in complying with self-direct EWR plans?

12 A. Staff recommends the Commission direct the Company to work with the
 13 Customer to establish an EWR plan in coordination with the stipulations in Case
 14 No. U-21627.¹ The Order in this case has the form for self-directing and it has
 15 expectations for a new build to reach the 1.5% target in their projected first year
 16 energy usage of operation.

17 Q. Does Case No. U-21627 explain how a new build can calculate its 1.5% target?

18 A. Yes, the Order explains how to rely on estimated future sales for the new build.

19 Q. Does Staff have a recommendation for the Company to make the Customer aware
 20 of Section 93 (9) of the Act?²

¹ [Case No. U-21627 Order Approves the revised forms and instructions](#)

² [Clean and Renewable Energy and Energy Waste Reduction Act – Act 295 of 2008](#)

DIRECT TESTIMONY OF KATIE J. SMITH
CASE NUMBER U-22058
PART II

1 A. Staff recommends the Commission order the Company to cooperate with the
2 Customer to make it aware of Section 93 (9) of the Act, which states: “....The
3 report shall provide sufficient information for the provider and the commission to
4 monitor progress toward the goals in the self-directed plan and to develop reliable
5 estimates of the energy savings that are being achieved from self-directed plans.”
6 Staff will be conducting audits and reviewing subsequent reports as they do with
7 all other EWR plans.

8 Q. Is the Customer required to meet the self-direct EWR goals?

9 A. Yes, Staff recommends the Company discuss with the Customer that there is a
10 financial penalty for not meeting the goals with newly implemented EWR
11 measures annually, and that self-direct plans must be multi-year in duration.

12 Q. In summary, what does Staff recommend the Commission order the Company to
13 do related to EWR?

14 A. Staff recommends the Commission order the Company to communicate the
15 requirements of Case No. U-21627, Section 93 (9) of the Act, and expectations of
16 self-directing an EWR plan to the Customer.

17 Q. Does this complete your testimony?

18 A. Yes, it does.

1 MR. SONNEVELDT: And finally, your Honor,
2 Staff, through stipulation with DTE, has one hearing room
3 exhibit, has been marked as S-4, and it is Confidential,
4 it consists of three pages of Confidential discovery
5 responses to Staff's Discovery Request No. 9.

6 JUDGE STALEY: All right. Thank you. Is
7 there any objection to the admission of Confidential
8 Exhibit, Hearing Room Exhibit S-4?

9 Hearing none, Confidential Exhibit S-4 is
10 admitted into evidence.

11 MR. SONNEVELDT: That is all for Staff,
12 your Honor.

13 JUDGE STALEY: All right. Thank you very
14 much.

15 I believe that covers all parties. Does
16 anyone else believe I've missed anything?

17 All right. This basically concludes the
18 close of the record in this matter. We are adjourned,
19 with initial briefs being due July 26 -- I'm sorry --
20 July 20 I believe -- I'm sorry -- July 20 of 2026, with
21 reply briefs due, be due August 3, 2026, and the
22 Commission will be reading the record.

23 Is there anything further for the record,
24 Mr. Janiszewski?

25 MR. JANISZEWSKI: Nothing from the
Penn Reporting, LLC - lori.penn@yahoo.com

1 Company your Honor. Thank you very much.

2 JUDGE STALEY: All right. Anything from
3 any other parties before we adjourn for the day?

4 Hearing none, we are adjourned for the
5 day. Thank you very much everyone for your
6 participation, and have a wonderful week. Oh, and don't
7 forget to file your official exhibits. Thank you.

8 (Collective "Thank you.")

9 (At 4:15 p.m., cross-examination concluded.)

10 - - -

11 (Transcript continues with Confidential bound-in
12 testimony on Page 895 of the Confidential Record.)

13 - - -

C E R T I F I C A T E

I, Lori Anne Penn (CSR-1315), do hereby
certify that I reported in stenotype via Microsoft Teams
the proceedings had in the above-entitled matter, that
being Case No. U-22058, before Theresa A.G. Staley, J.D.,
Administrative Law Judge with Michigan Office of
Administrative Hearings and Rules, for the Michigan
Public Service Commission, Lansing, Michigan, on Tuesday,
June 30, 2026; and do further certify that the foregoing
transcript, consisting of Volume 3 PUBLIC RECORD, pages
62-894, constitutes a true and correct transcript of my
stenotype notes.

Lori Anne Penn

Lori Anne Penn, CSR-1315
Penn Reporting, LLC
lori.penn@yahoo.com

Dated: July 8, 2026