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August 16, 2024

VIA ELECTRONIC CASE FILING

Executive Secretary
Michigan Public Service Commission
7109 W. Saginaw Highway
Lansing, Michigan 48917

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

Dear Executive Secretary:

Enclosed for filing please find the ***Proof of Service*** as it relates to the Association of Businesses Advocating Tariff Equity's following documents in the above-referenced matter:

1- Rebuttal Testimony & Exhibits of James R. Dauphinais
2- Rebuttal Testimony & Exhibits of Brian C. Andrews
3- Rebuttal Testimony of Christopher C. Walters

Sincerely,

CLARK HILL PLC

Stephen Campbell

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Stephen A. Campbell

SAC/lkd
cc: Parties of Record

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

Rebuttal Testimony and Exhibits of

James R. Dauphinais

On behalf of

Association of Businesses Advocating Tariff Equity

August 16, 2024

BRUBAKER & ASSOCIATES, INC.

Project 11638

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

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Rebuttal 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 ARE YOU THE SAME JAMES R. DAUPHINAIS WHO PREVIOUSLY FILED DIRECT TESTIMONY ON JULY 26, 2024 ON BEHALF OF ASSOCIATION OF BUSINESSES ADVOCATING TARIFF EQUITY ("ABATE")?

A Yes, I am.

Q WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A My rebuttal testimony addresses the Direct Testimony of Citizens Utility Board of Michigan ("CUB"), Sierra Club ("SC"), Michigan Environmental Council ("MEC"), and Natural Resources Defense Council ("NRDC") (collectively, "MNSC") witness Douglas B. Jester with respect to his proposal to change the demand portion of the current DTE Electric Company ("DTE" or "Company") 4-CP 75-0-25 production facility cost allocator

used in DTE's Class Cost of Service ("CCOS") Study from being based on customer class demand at the time of DTE's four summer monthly system peaks (June, July, August and September) (i.e., summer four coincident peak ("4-CP") demand) to being based on what he refers to as a "weighted incremental share of production plant by season" method, or, in the alternative, a 9-CP demand method that uses the class monthly coincident peak demands of March through November.[1] I also address MNSC witness Jester's related rate design proposal with respect to the recovery in rates of the production facility costs allocated to each customer class.[2] Finally, I briefly address his proposal to change DTE's distribution rate design to be based on seasonal distribution capacity utilization.[3]

In addition, I address the Direct Testimony of Michigan Energy Innovation Business Council ("Michigan EIBC"), Institute for Energy Innovation ("IEI") and Advanced Energy United ("United") (collectively, "MEIU") witness Dr. Laura S. Sherman with respect to her proposal to require DTE to account for societal benefits, including greenhouse gas and criteria pollutant emissions reductions, in its benefit to cost analysis for its Transportation Electrification Plan ("TEP").[4]

My silence with regard to any issue should not be construed as an endorsement of the position of any party on that issue in this proceeding.

Q PLEASE BRIEFLY SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS IN THIS PROCEEDING.

A My rebuttal testimony conclusions and recommendations are as follows:

- MNSC witness Jester's proposal to modify the demand portion of DTE's current 4-CP 75-0-25 production facility allocator to use either a "weighted incremental share

[1]Jester Direct at 12-20 and 44.
[2]Jester Direct at 21-23 and 44.
[3]Jester Direct at 23 and 44.
[4]Sherman Direct at 24-36 and 64.

of production plant by season" method or, alternatively, a 9-CP method, rather than the current 4-CP method, is not reasonable for the following reasons:

- MNSC witness Jester, with respect to MISO's capacity credit requirements, only considered the MISO-wide requirement. He failed to consider the MISO Local Clearing Requirement ("LCR") for MISO Local Resource Zone ("LRZ" or "Zone") 7, the Zone DTE is located within, and how DTE's peak system demand, not DTE's demand at the time of the MISO-wide system peak, drives that need.

- MNSC did not update the system peak demand test analyses that were performed in Case No. U-17689 by DTE and ABATE and were the basis of the Commission's adoption of the 4-CP method in that proceeding. As I present in my testimony herein, when those analyses are updated, they show an even stronger case for the use of 4-CP for DTE than they did in Case No. U-17689.

- Even if DTE's MISO-wide capacity credit requirement for each season were alone used to determine the appropriate demand allocation for production facility costs, which as I have noted should not be done, that information at best potentially supports the use of a summer 5-CP (May, June, July, August and September) demand allocation, not a March through November 9-CP allocation or MNSC witness Jester's "weighted incremental share of production plant by season" method.

- For the foregoing reasons, MNSC witness Jester's proposal in this proceeding with respect to changing the demand portion of DTE's production plant cost allocator from a 4-CP method should be rejected and the current 4-CP method should continue to be used.

- In addition, given his production facility cost rate design proposal was contingent on Commission adoption of one of his proposed changes to the demand portion of DTE's production plant cost allocator, that proposal should be rejected as well.

- With respect to MNSC witness Jester's proposal to have the Commission require DTE in its next rate case to file a distribution rate design based on seasonal utilization, ABATE cautions that utilization and cost causation are not necessarily always in alignment. As such, while ABATE does not object to MNSC's purely informational request for the next rate case filing by DTE, ABATE reserves the right to respond to any proposals in future DTE rate proceedings for DTE to actually adopt a distribution class cost of cost service method or distribution rate design based on seasonal utilization.

- With respect to MEIU witness Sherman's proposal for the Commission to require DTE to account for societal benefits, including greenhouse gas and criteria pollutant emissions reductions, in its benefit to cost analysis for its TEP, while ABATE would not object to the use of the Societal Cost Test ("SCT") or societal benefits for informational purposes as a sensitivity case, the Commission should not require DTE use the SCT, or any other inclusion of societal benefits, including greenhouse gas and criteria pollutant emissions, in DTE's base case BCA for its TEP. In addition, DTE's TEP should not be expanded on the basis of societal benefits associated with avoided transportation emissions, as that would amount to

mandating electric ratepayers subsidize the cost of providing the claimed societal benefits and is likely be beyond the authority of the Commission to require.

II. Response to MNSC Production Facility Cost Allocation and Rate Design Proposals

A. Background on the Current 4-CP 75-0-25 Production Facility Cost Allocator

Q PLEASE BRIEFLY DESCRIBE DTE'S CURRENT 4-CP 75-0-25 PRODUCTION FACILITY COST ALLOCATOR AND HOW THE DEMAND PORTION OF THAT ALLOCATOR CAME TO BE BASED ON 4-CP DEMAND.

A The 4-CP 75-0-25 production facility cost allocator is used in DTE's CCOS Study to allocate production facility costs to customer classes. Production facility costs (or fixed production costs) are the costs associated with the recovery of the capital expenditures for DTE's generation facilities -- specifically, the cost of capital, depreciation expense and taxes associated with those capital expenditures. DTE's production facility costs do not include the fuel or non-fuel O&M costs of DTE's generation facilities. They also do not include DTE's purchased power expenses. However, DTE's capacity-related purchased power expenses recovered through base rates are currently separately allocated to customer classes using a 4-CP 100-0-0 allocator that uses the same 4-CP method as DTE's 4-CP 75-0-25 production facility cost allocator.

Under the 4-CP 75-0-25 production facility cost allocator, which has been used by DTE since the Commission's Final Order in Case No. U-17689 in 2015, 75% of production facility costs are allocated based on the demand of each customer class at the time of DTE's four summer monthly peaks (June, July, August and September) (i.e., summer 4-CP demand) and 25% of production facility costs are allocated based on the annual energy consumption of each customer class.

Use of the 4-CP method for the demand allocation portion of the overall 4-CP 75-0-25 allocator was proposed and supported by DTE and ABATE in the direct testimony they each provided in Case No. U-17689. That testimony included a review of system demand tests that showed DTE is a summer peaking utility and that DTE's production facilities costs should be allocated to customer classes using four summer coincident peaks (June, July, August and September) for the demand allocation portion of the overall production facility cost allocator.[5] The Commission Staff ("Staff') in Case No. U-17689 concurred with this conclusion.[6] The Commission found the following:

> "The Commission agrees with DTE Electric, the Staff, and ABATE, that a change from a 12CP to a 4CP demand allocator is fully supported by the evidence presented in this proceeding. Martin L. Heiser, Consultant, Regulatory Economics for DTE Energy Corporate Services, LLC, explained that the company applied four system demand tests that have been used by the Federal Energy Regulatory Commission to determine the appropriate demand portion of the allocator. The results of these tests are consistent with the results for other utilities for which FERC has authorized a 4CP allocator. *See*, 2 Tr 234-236; Exhibit A-14. The Commission therefore rejects the ALJ's recommendation to retain the 12CP demand allocator."[7]

Q PLEASE EXPLAIN THE BASIS OF ALLOCATING PRODUCTION FACILITY COSTS BASED ON CUSTOMER CLASS DEMAND COINCIDENT WITH THE TIME OF A UTILITY'S SYSTEM PEAK.

A The total amount of production facility capacity a utility needs is directly dependent on the total demand of its load at the time of its annual system peak. Furthermore, it is solely dependent upon this if the capacity the utility acquires to reliably meet its annual system peak is alone sufficient to reliably serve the utility's load for the balance of the year, including during periods of scheduled production facility maintenance outages.

[5]Case No. U-17689, Final Order, June 15, 2015 at 3-5.
[6]*Id.* at 5.
[7]*Id.* at 20.

The higher the demand of a customer class at the time of the utility's system peak, the more that customer class contributes to the utility's total demand at the utility's system peak and, thus, the utility's total need for production facility capacity. Hence, it is appropriate to allocate production facility costs to customer classes based on the demand of the customer class at the time of (i.e. coincident with) the utility' system peak.

Q PLEASE EXPLAIN WHY MORE THAN ONE COINCIDENT PEAK IS SOMETIMES USED.

A When only customer class demand at the time of the annual system peak for the utility is utilized for allocating production facility costs, the method is typically referred to as a 1-CP method. The 1-CP method is an appropriate method when the utility's demand at its annual system peak is significantly higher than its demand at the time of its system peaks in other months such that the utility's load can be reliably served throughout the rest of the year without additional production facility capacity while accommodating scheduled maintenance outages for the utility's fleet of production facilities.

However, when the time of the utility's annual system peak moves around between a few adjacent months such that those monthly system peaks on average over several years are very close in magnitude, it may be more appropriate to allocate production facility costs to customer classes based on demand of each customer class at the time of the system peak of the utility in each of those months. This is what was found to be the case for DTE through the system peak tests DTE and ABATE presented in their respective direct testimonies in Case No. U-17689. Specifically, as I have noted, both DTE and ABATE found from the application of system demand tests that the demand allocation for DTE's production facility costs should be based on customer

class demand at the time of DTE's monthly system peaks during the summer months of June, July, August and September.

Q PLEASE EXPLAIN HOW THE NUMBER OF MONTHLY COINCIDENT PEAKS UTILIZED IS DETERMINED FROM SYSTEM PEAK TESTS SUCH AS THOSE THAT WERE PERFORMED BY DTE AND ABATE IN CASE NO. U-17689.

A The appropriate number of monthly coincident peaks to utilize for allocation is typically determined by performing what are referred to as system peaks tests over several years of historical data. This is what DTE and ABATE did in their testimony in Case No. U-17689.

DTE witness Heiser, in his direct testimony in Case No. U-17689, used a method under which the utility's demand at each of its monthly system peaks over several years is run through four tests that are based on past Federal Energy Regulatory Commission ("FERC") precedent with respect to awarding specific numbers of CPs to various utilities for production facility cost allocation in wholesale electric service ratemaking. Mr. Heiser used six years of DTE historical data, for 2008 through 2013, from FERC Form 1 and compared the use of 1-CP, 3-CP, 4-CP and 12-CP. From his analysis, he arrived at the conclusion that the results of the tests for DTE using the six years of historical data he examined were consistent with those of other utilities for which FERC has allowed the 4-CP method of allocating production facility costs.[8] Specifically, his results showed use of 4-CP demand for DTE passed all four of the system demand tests he utilized that are based on FERC precedent.[9]

In Case No. U-17689 ABATE witness Selecky used a method in which he utilized ten years, rather than six years, of DTE historical data, for 2004 through 2013,

[8]Case No. U-17689 at 2 Tr 234-236 and Exhibit A-14.
[9]*Id.*

from FERC Form 1 and then calculated DTE's average system peak demand for each month over that ten-year period. He found July had the highest average system peak demand and the average system peak demands for June, August and September were, respectively, 94%, 98% and 87% of the July value. He also found that DTE's average system peak demand in all other months was 76% or lower than that for July. He concluded these results support the use of no more than 4-CP (June, July, August and September) demand for DTE and that a case could be made from them for the use of 3-CP demand instead of 4-CP demand given the drop off from the 94% of the July result for June to the 87% of the July result for September.[10]

Q AT THE TIME OF CASE NO. U-17689, WAS DTE A MEMBER OF THE MIDCONTINENT INDEPENDENT SYSTEM OPERATOR, INC. ("MISO") AND WAS THIS CONSIDERED BY EITHER MR. HEISER OR MR. SELECKY?

A DTE was a member of MISO at the time of Case No. U-17689 and Mr. Selecky addressed the relevance of this in his direct testimony in that proceeding. He noted DTE was subject to MISO's resource adequacy requirements that impose a capacity requirement on DTE based on DTE's forecasted system demand at the time of MISO's annual system peak -- a 1-CP allocation method. Mr. Selecky also noted that MISO's annual system peak in the most recent past five years had consistently occurred in summer months, specifically June and July. This further supported the use of no more than 4-CP (June, July, August and September) as the demand allocation for production facility costs for DTE.[11] In addition, it should be noted that MISO then, and today, defines it summer season as consisting only of the calendar months of June, July and August. It does not include September. As a result, this was further evidence that a

[10]Case No. U-17689 at 3 Tr 476 and Exhibit AB-1.
[11]Case No. U-17689 at 3 Tr 476-477.

case at the time could have been made to use a 3-CP demand allocator for DTE rather than a 4-CP demand allocator for DTE. Hence, the selection of the 4-CP allocator at the time was conservative.

B. MNSC Witness Jester's Proposed Modifications to the Current 4-CP 75-0-25 Production Facility Cost Allocator and Associated Rate Design

Q PLEASE BRIEFLY SUMMARIZE MNSC WITNESS JESTER'S PROPOSAL IN THIS CURRENT PROCEEDING WITH RESPECT TO DTE'S PRODUCTION PLANT COST ALLOCATOR AND RATE DESIGN ASSOCIATED WITH THE RECOVERY OF THOSE COSTS FORM CUSTOMER CLASSES.

A MNSC witness Jester proposes to change the current summer four month coincident peak ("Summer 4-CP") demand method used for the demand allocated portion of fixed production costs to either what he refers to as a "weighted incremental share of production plant by season" method, or, in the alternative, a nine month coincident Peak ("9-CP") demand method that includes the monthly coincident peaks of March through November.[12] He justifies his proposal on the basis of MISO's June 2023 move from an annual to seasonal resource adequacy construct, MISO's definition of seasons, and the utilization by DTE's load in each season of the seasonal capacity credits (specifically, MISO Zonal Resource Credits ("ZRCs")) DTE has from its production facilities, purchased capacity and other sources.[13]

In addition, if the Commission accepts either of his proposed modifications to DTE's current 4-CP 75-0-25 production facility cost allocator, MNSC witness Jester proposes DTE's rate design for the recovery of demand allocated production facility

[12]Jester Direct at 18-20 and 44.
[13]Jester Direct at 14-18.

costs through capacity charges be modified to essentially mimic his proposed cost allocation of those costs to customer classes.[14]

Q IS MNSC WITNESS JESTER'S PROPOSAL WITH RESPECT TO MODIFYING THE DEMAND PORTION OF DTE'S CURRENT 4-CP 75-0-25 PRODUCTION PLANT COST ALLOCATOR REASONABLE?

A MNSC witness Jester's proposal to modify the demand portion of DTE's current 4-CP 75-0-25 production facility allocator to use either a "weighted incremental share of production plant by season" method or, alternatively, a 9-CP method, rather than the current 4-CP method, is not reasonable and, as a result, should be rejected by the Commission. The proposal is not reasonable for the following reasons:

- MNSC witness Jester, with respect to MISO's capacity credit requirements, only considered the MISO-wide requirement. He failed to consider the MISO Local Clearing Requirement ("LCR") for MISO Local Resource Zone ("LRZ" or "Zone") 7, the Zone DTE is located within, and how DTE's peak system demand, not DTE's demand at the time of the MISO system peak, drives that need.

- MNSC did not update the system peak demand test analyses that were performed in Case No. U-17689 by DTE and ABATE and were the basis of the Commission's adoption of the 4-CP method in that proceeding. As I present later in this testimony, when those analyses are updated, they show an even stronger case for the use of 4-CP for DTE than they did in Case No. U-17689.

- Even if DTE's MISO-wide capacity credit requirement for each season was alone used to determine the appropriate demand allocation for production facility costs, which as I have noted should not be done, that information at best potentially supports the use of a summer 5-CP (May, June, July, August and September) demand allocation, not a March through November 9-CP allocation or MNSC witness Jester's "weighted incremental share of production plant by season" method.

For these reasons, MNSC witness Jester's proposal in this proceeding with respect to changing the demand portion DTE's production plant cost allocator from a 4-CP method should be rejected and the current 4-CP method should continue to be

[14]Jester Direct at 21-23 and 44.

used. Given his production facility cost rate design proposal was contingent on Commission adoption of one of his proposed changes to the demand portion of DTE's production plant cost allocator, that proposal should be rejected as well.

Q PLEASE EXPLAIN THE MISO LCR AND WHY MNSC WITNESS JESTER'S FAILURE TO CONSIDER IT IS UNREASONABLE.

A MISO's resource adequacy requirements require that both a Zone's share of its MISO-wide capacity requirement, the Zone's Planning Reserve Margin Requirement ("PRMR"), be met and the Zone's LCR be met.[15] If the LCR is not met for a Zone for a particular season, it causes the Zone's loss of load probability to exceed MISO's annual target of no more than one loss of load event day in ten years and causes MISO to set the daily Auction Clearing Price ("ACP") for that season to an amount potentially as high as four times the MISO annual daily gross Cost of New Entry ("CONE") price.[16] For Zone 7, the MISO Zone in which DTE's load is located, for the MISO 2024/2025 Planning Year, this would have been four times $348.32 per MW-day, or $1,393.28 per MW-day.[17]

Given the foregoing consequences, the LCR cannot be ignored when considering the appropriate allocation of production facility costs as MNSC witness Jester did in his direct testimony. This is particularly important for MISO Zone 7 because the Zone 7 LCR typically makes up a very large percentage of the Zone 7 PRMR. For example, for Zone 7 for the MISO 2024/2025 Planning Year, the MISO Summer LCR is approximately 89% of the MISO Summer PRMR, the MISO Fall LCR

[15]MISO Tariff, Module E-1 at Sections 68 and 69A.
[16]MISO Tariff, Module E-1, Sections 69A.7.1 a. and x.
[17]MISO Presentation "Planning Resource Auction Results for Planning Year 2024/2025, April 25, 2024 (https://cdn.misoenergy.org/2024%20PRA%20Results%20Posting%20202404256326 65.pdf) at Slide 26.

is approximately 98% of the MISO Fall PRMR, the MISO Winter LCR is approximately 101% of the Winter PRMR, and the MISO Spring LCR is approximately 83% of the Spring PRMR.[18] Production facility capacity located within Zone 7 can simultaneously meet both the Zone 7 LCR and the Zone 7 PRMR. However, production facility capacity located outside of Zone 7 can only be used to meet the Zone 7 PRMR -- it cannot be used to meet the Zone 7 LCR.

In addition, the LCR for a Zone is directly dependent on the Local Reliability Requirement ("LRR") for the Zone, which is determined by multiplying a LRR ratio (determined by MISO in its annual Loss of Load Expectation Study) by the forecasted peak system demand of the Zone, not the forecasted demand of the Zone at the time of MISO's peak system demand.[19] As a result, the LCR for a Zone is not driven by MISO-wide system peaks, but instead the peak system demand of the Zone, which can be significantly higher than the demand of that Zone at the time of the MISO-wide system peaks. Furthermore, in the case of Zone 7, DTE's system demand is the single largest driver of system demand in the Zone as DTE's system demand makes up approximately 50% of total system demand within Zone 7.[20]

In summary, the LCR of Zone 7 is as important as, if not more important than, the PRMR for Zone 7 and DTE's system demand is the largest single driver of the magnitude of the LCR for Zone 7, not MISO-wide system demand. As a result, the nature of DTE' system peaks is as important of a consideration, if not a more important consideration, with respect to the total amount of production facility capacity DTE needs, as the nature of the MISO-wide capacity requirements. Witness Jester's

[18]MISO Presentation "Planning Resource Auction Results for Planning Year 2024/2025, April 25, 2024 (https://cdn.misoenergy.org/2024%20PRA%20Results%20Posting%20202404256326665.pdf) at Slides 16-19.

[19]MISO Tariff, Module E-1 at Section 69A.5.

[20]DTE's total system demand is the neighborhood of 10,000 MW while the total system demand for Zone 7 is in the neighborhood of 20,000 MW.

approach to basing his recommendation on the MISO-wide capacity credit requirement without considering the Zone 7 LCR therefore fails to accurately reflect the relevant peak system demand.

Q PLEASE EXPLAIN WHY MNSC'S FAILURE TO UPDATE THE SYSTEM PEAK TESTS PERFORMED IN CASE NO. U-17689 IS UNREASONABLE.

A There are two reasons. First, as I have discussed earlier in this testimony, the results of system peak tests performed for, and presented in, Case No. U-17689 were the basis upon which the 4-CP method was proposed by DTE and ABATE and what the Commission cited, in conjunction with the remainder of the record, in approving the use of the 4-CP method by DTE. Second, as I have discussed, the nature of DTE's system peaks is still relevant with respect to determining the allocation of DTE's production facility costs since it is the single largest driver of the Zone 7 LCR.

Q HAVE YOU PERFORMED AN UPDATE OF THE SYSTEM PEAK TESTS ANALYSES THAT WERE PERFORMED IN CASE NO. U-17689?

A Yes, I have downloaded from the FERC website DTE's FERC Form 1 filings and utilized DTE's reported monthly system peak data on page 401b of its FERC Form 1 filings to update the system peak tests performed in Case No. U-17689 by both DTE witness Heiser and ABATE witness Selecky. I have provided the update of DTE witness Heiser's system peaks tests analysis as Exhibit AB-19. I have provided the update of ABATE witness Selecky's system peak tests as Exhibit AB-20.

My update of DTE witness Heiser's analysis uses DTE's monthly system peaks for six years from 2018 through 2023. It shows that all four of the FERC precedent

tests continue to be passed for 4-CP.[21] In addition, the updated analysis shows September has grown in merit with respect to being included in the monthly CPs. Specifically, in DTE witness Heiser's original analysis from Case No. U-17689, five of the DTE annual system peaks occurred in July and one in June.[22] In my update of his analysis, one of the annual peaks occurred in June, two occurred in July, one occurred in August and two occurred in September.[23] Note that none of DTE's annual system peaks occurred during May or during any other month besides the current DTE 4-CP months of June, July, August and September.[24]

My update of ABATE witness Selecky's Case No. U-17689 analysis, which I have provided in Exhibit AB-20, uses DTE's monthly system peaks for the ten years from 2014 through 2023. It also shows that that 4-CP continues to be appropriate for DTE and that September has grown in merit with respect to being included in the monthly CPs. Specifically, in the updated analysis, July remains the highest average monthly peak system demand month and the average monthly system peak demand for June, August and September, as a percentage of July's average peak system demand, are respectively 95%, 98% and 93%.[25] All other months are at 81% or lower.[26] September grew from 87% of July demand in ABATE witness Selecky's original analysis in Case No. U-17689 to 93% of July demand in my update of his analysis -- a six-percentage point increase.[27] While May grew from 76% to 81%, a five-percentage point increase,[28] this is a slower rate of growth than for September and, more

[21]Exhibit AB-19 at page 1, lines 25 through 29.
[22]Case No. U-17689, Exhibit A-14 at page 2, lines 6 through 7.
[23]Exhibit AB-19 at page 2, lines 6 through 9.
[24]Exhibit AB-19 at page 2, lines 1 through 13.
[25]Exhibit AB-20 at lines 6-9.
[26]*Id.* at lines 1 through 5 and lines 10 through 12.
[27]Comparing Exhibit AB-20 at line 9 to Case No. U-17689, Exhibit AB-1 at line 9.
[28]Comparing Exhibit AB-20 at line 5 to Case No. U-17689, Exhibit AB-1 at line 5.

1 importantly, May's 81% of July demand in the updated analysis is still much less than
2 the 95%, 98% and 93% of July demand for June, August and September.

3 **Q YOU INDICATED EARLIER THAT DTE'S SYSTEM DEMAND IS THE LARGEST**
4 **SINGLE DRIVER OF MISO ZONE 7 SYSTEM DEMAND AND, AS A RESULT, DTE'S**
5 **SYSTEM DEMAND IS THE SINGLE LARGEST DRIVER OF THE MISO ZONE 7 LCR**
6 **VALUE. CAN YOU PROVIDE EVIDENCE THAT SUPPORTS THAT THE MISO**
7 **ZONE 7 LCR, JUST LIKE DTE'S SYSTEM DEMAND, EXHIBITS 4-CP**
8 **CHARACTERISTICS?**
9 A Yes. The MISO Zone 7 LCR values for the MISO 2024/2025 Planning Year are 19,271
10 MW for Summer, 19,443 MW for Fall, 17,597 MW for Winter and 16,372 MW for
11 Spring.[29] The MISO Winter and MISO Spring LCR values for Zone 7 are well below
12 the MISO Summer and MISO Fall LCR values. This is consistent with a 4-CP allocation
13 that excludes the six calendar months associated with these two MISO seasons
14 (December, January, February, March, April and May). In addition, as I will discuss
15 further later in this testimony, since January 2016, MISO has been compiling the date
16 and time of the monthly and seasonal MISO-wide and Zonal system peaks. That
17 historical information shows that, to date, the MISO Fall seasonal Zone 7 system peak
18 has always occurred in September, never in October or November. This is also
19 consistent with a 4-CP allocation, as the exclusion of these two additional months
20 (October and November) only leaves the four months: the three MISO Summer months
21 of June, July and August and the one MISO Fall month of September. Hence, the

[29]MISO Presentation "Planning Resource Auction Results for Planning Year 2024/2025, April 25, 2024 (https://cdn.misoenergy.org/2024%20PRA%20Results%20Posting%20202404256326655.pdf) at Slides 16-19.

MISO Zone 7 LCR is driven by the same 4-CP (June, July, August and September) demand that drives DTE's system peaks.

Q YOU HAVE EXPLAINED WHY DTE'S SEASONAL MISO-WIDE CAPACITY CREDIT REQUIREMENTS (I.E, DTE'S SEASONAL PRMR VALUES) SHOULD NOT BE USED ALONE TO DETERMINE THE APPROPRIATE DEMAND ALLOCATION FOR DTE'S PRODUCTION FACILITY COSTS AND THAT THE NATURE OF DTE'S SYSTEM PEAKS SHOULD BE GIVEN SIMILAR OR GREATER WEIGHT. IN ADDITION, YOU HAVE INDICATED THAT, EVEN IF DTE'S SEASONAL PRMR WAS USED ALONE TO DETERMINE THE APPROPRIATE DEMAND ALLOCATION FOR DTE'S PRODUCTION FACILITY COSTS, IT WOULD NOT SUPPORT A MARCH THROUGH NOVEMBER 9-CP DEMAND METHOD OR MNSC WITNESS JESTER'S "WEIGHTED INCREMENTAL SHARE OF PRODUCTION PLANT BY SEASON" METHOD. PLEASE EXPLAIN WHY THIS IS SO.

A MNSC witness Jester developed his recommendation that the Commission adopt either his "weighted incremental share of production plant by season" method, or, alternatively, a 9-CP (March through November) demand method, based on a comparison of DTE's seasonal PRMR (MISO-wide Required ZRCs) to the seasonal ZRCs DTE has available from its production facilities, its purchased capacity and other sources to meet its PRMR (Accredited ZRCs) that he presented on pages 17 and 18 of his direct testimony. In his comparison contained in a confidential table on page 18 of his direct testimony, he calculated the ratio for each MISO season of DTE's Megawatts ("MWs") of PRMR to DTE's MWs of Available ZRCs, which he labeled as DTE's "ZRC utilization percentage." While the table as witness Jester presented it is confidential, the "utilization percentage" values for each season are also identified on

pages 18 and 19 of the public version of his direct testimony. Furthermore, DTE's available ZRCs surplus for each season as a percentage of DTE's PRMR can be derived from the "ZRC utilization percentage" values since it is simply 100% less the inverse of the "ZRC utilization percentage" values. Based on this public information, I have tabulated for each MISO season for the 2024/2025 Planning Year DTE's "ZRC utilization percentage" values and DTE's ZRC surplus values in Table JRD-Rebuttal-1 below.

Table JRD-Rebuttal-1

2024/2025 PY – Comparison of DTE PRMR to DTE Available ZRCs

Description	MISO Summer	MISO Fall	MISO Winter	MISO Spring
DTE ZRC Utilization %	98.4%	98.2%	71.9%	96.5%
DTE's Surplus ZRCs as % of DTE's PRMR	1.6%	1.9%	39.1%	3.6%

Source: Public Jester Direct at 18-19.

Based on the seasonal "DTE ZRC utilization values" presented above, MNSC witness Jester first recommended that a Spring/Summer/Fall 9-CP method be adopted claiming it was "close to the Commission's past practice of allocating Production Plant Demand cost based on the months during which DTE Electric's Production Plant portfolio is most heavily utilized".[30]

He then proceeded to claim that the 9-CP method, despite utilizing seasonal PRMR and ZRC values, failed to "adjust the nominal MW of customer demand for the seasonality of the resources needed to support that load."[31] To address this claimed

[30] Jester Direct at 18.
[31] *Id.*

shortcoming of the 9-CP method, he proposed his "weighted incremental share of production plant by season" method and indicated that it was his preferred method.[32] Under his "weighted incremental share of production plant by season", witness Jester, instead of focusing on the seasons that drive DTE's total Production Facility capacity need, focuses on the Season that clearly does not, MISO Winter. He essentially argues the percent of DTE's total production facility capacity necessary to meet DTE's MISO Winter PRMR (71.9%) is needed in all seasons and therefore that percentage of DTE's Production Facility Costs should be first allocated to customer classes based on 12-CP demand. He then incrementally works his way up to MISO Spring and argues the additional capacity necessary to cover MISO Spring (24.6% = 96.5% - 71.9%) should be allocated to customer classes on a Spring/Fall/Summer 9-CP demand method. He then further moved incrementally up to MISO Fall and argues the additional necessary capacity to cover MISO Fall (1.6%) should be allocated using a Summer/Fall 6-CP method. Finally, he proposed the amount of additional capacity to get up to 100% and also cover MISO Summer (1.8%) would be allocated using a summer 3-CP (June, July and August) demand method.[33]

Both of MNSC witness Jester's proposals and his rationales underlying them are seriously flawed, inconsistent with cost causation and not supported by the data witness Jester utilized.

Q PLEASE EXPLAIN WHY MNSC WITNESS JESTER'S 9-CP PROPOSAL AND THE RATIONALE UNDERLYING IT ARE SERIOUSLY FLAWED.

A With respect to MNSC witness Jester's 9-CP proposal, his claim about the Commission allocating Production Plant Demand cost based on the months during which DTE

[32] *Id*. at 18-19.
[33] *Id.* at 19.

Electric's Production Plant portfolio is most heavily utilized is not an accurate characterization of how the current 4-CP method was arrived at in Case No. U-17689. The current 4-CP method that was approved in Case No. U-17689 was based on the results of system demand tests, which are used to determine the monthly system peaks that that drive the total amount of production facility capacity DTE needs in order to reliably serve its load over the entire year.[34] The tests explicitly exclude from those monthly system peaks the months where system peak demand does not rise to the level of requiring production facility capacity near that necessary at the annual system peak. Specifically, the system demand tests are designed to determine the months where customer demand at the time of the system peak will affect the total amount of production facility capacity the utility needs. As such, the system demand tests are designed to determine cost causation consistent with cost of service principles, something that utilization does not generally reflect.

This said, if MISO-wide capacity credit requirements (i.e., PRMR) are considered alone, the data MNSC witness Jester utilized that I have summarized in my Table JRD-Rebuttal-1 would potentially support DTE's system demand at the time of MISO Spring, Sumer and Fall <u>seasonal</u> system peaks driving DTE's total required amount of ZRCs. However, it is very important to note that the data does <u>not</u> potentially support a 9-CP (March through November) demand method. It only potentially supports a 5-CP (May through September) demand method at best. The reason for this is twofold.

First, MISO does not allocate seasonal PRMR amounts to Load Serving Entities ("LSEs"), including DTE, on the basis of the LSE's demand at the time of each of the three monthly MISO-wide system peaks of the season, which would be a 3-CP

[34]Case No. U-17689, Final Order, June 15, 2015 at 3-5 and 20.

seasonal allocation method. Instead, MISO allocates seasonal PRMR to LSEs based on the forecasted demand of the LSE at the time of the MISO-wide system peak for the season, which is a 1-CP seasonal allocation method.[35]

Second, it is important to note that the MISO Fall (September through November) and Spring (March through May) seasons each include months within them that have very different characteristics. Specifically, for Fall, September is predominately a cooling load month while November is predominately a heating load month. Similarly, with respect to Spring, May is predominantly a cooling load month while March is predominately a heating load month. Because of this and MISO being a summer peaking system, MISO's Fall MISO-wide and Fall Zone 7 system peaks have always occurred in September and MISO's Spring MISO-wide and Spring Zone 7 system peaks have nearly always occurred in May. This is shown in Exhibit AB-21, which is a file MISO maintains of the date and time of its historical seasonal MISO-wide and Zonal system peaks from January 2016 to date.[36] In this file (Exhibit AB-21), MISO highlights in orange coloring the monthly system peak for each season on which the seasonal system peak occurred. For the MISO Summer and Winter seasons, the seasonal system peak has been fairly evenly distributed over the MISO Summer and Winter months both on a MISO-wide and Zone 7 basis, but for the MISO Fall season the system peak has always occurred in September and for the MISO Spring season the system peak has, except on one occasion, always occurred in May. This is summarizing in Table JRD-Rebuttal-2 below:

[35]MISO Tariff, Module A at Section 1.C and Module E-1 at Section 68A.7.

[36]The version of the file provided in Exhibit AB-21 was accessed on August 11, 2024. The latest version of this file can be accessed from the MISO website at: https://cdn.misoenergy.org/Historical%20Monthly_Seasonal%20Peak%20Dates%20and%20Times%20MISO%20LRZ_Settled%20Load%20(Spring%202024)636872.xlsx.

Table JRD-Rebuttal-2

Historical Frequency of Seasonal System Peak Occurrence
January 2016 through May 2024

MISO Season	Calendar Month	Number of Times Seasonal MISO-wide System Peak Occurred in Month	Number of Times Seasonal MISO Zone 7 System Peak Occurred in Month
Summer	June	2	1
Summer	July	3	5
Summer	August	3	2
Fall	September	8	8
Fall	October	0	0
Fall	November	0	0
Winter	December	2	3
Winter	January	5	5
Winter	February	2	1
Spring	March	1	1
Spring	April	0	0
Spring	May	8	8

Source: Exhibit AB-21

Given these results, it would be appropriate to include June, July and August CP demand for Summer since the MISO-wide seasonal system peak occurs in all three months on a regular basis and, as a result, demand at the time of any of those monthly system peaks could impact the amount of PRMR the LSE (i.e., DTE) is assigned for that season in the future. However, it would not be appropriate to include either October and November CP demand for Fall or March and April CP demand for Spring since the MISO-wide seasonal system peak is unlikely to occur in those months such that demand at the time of the MISO-wide system peaks during these months is unlikely

to impact the amount of PRMR the LSE is assigned in the future for Fall and Spring. For these reasons, as I have indicated, even if DTE's MISO-wide capacity credit requirement for each season could be used alone to determine the appropriate demand allocation for production facility costs, which it cannot, that information at best potentially supports the use of a 5-CP (May, June, July, August and September) demand allocation method, not a March through November 9-CP demand allocation.

Given the reasons I have discussed with respect to why DTE's system peaks are still relevant with respect to determining the appropriate CP method, my update of the system demand tests performed in Case No. U-17689 supporting continuation of a summer (June, July, August and September) 4-CP method for DTE, and DTE's MISO-wide capacity requirements at best potentially supporting a 5-CP (May, June, July, August and September) method, MNSC witness Jester's proposal to change the demand allocation portion of DTE's current 4-CP 75-0-25 production facility cost allocator from the current 4-CP (June, July, August and September) demand method to a 9-CP (March through November) demand method should be rejected and the current 4-CP method continued.

Q PLEASE EXPLAIN WHY MNSC WITNESS JESTER'S "WEIGHTED INCREMENTAL SHARE OF PRODUCTION PLANT BY SEASON" METHOD PROPOSAL AND THE RATIONALE UNDERLYING IT ARE SERIOUSLY FLAWED.

A First, MNSC witness Jester does not explain what he means with respect to why a traditional CP method using ZRCs rather than nominal MW fails to "adjust the nominal MW of customer demand for the seasonality of the resources needed to support that load using ZRCs in place of nominal MW". Nor does he explain how his "weighted

incremental share of production plant by season" method addresses the claimed problem.

Second, MNSC Jester's "weighted incremental share of production plant by season" method is not based on cost causation. As he readily admits in his direct testimony, it is instead based on the idea that "Production Plant capacity should be allocated to customer classes based on the seasons in which the Production Plant is used."[37] Usage and cost causation are not the same. To be clear, the data summarized in Table JRD-Rebuttal-1 shows that DTE has a very large Winter 2024/2025 ZRC surplus equal to 39.1% of its total MISO-wide PRMR for that season. This is very likely due to a combination of DTE's monthly system peaks in December, January and February being 64% to 66% of DTE's annual system peak in the summer[38] and DTE's current production facility fleet likely being accredited a largely similar amount of ZRCs in the winter as in the summer. Given this level of ZRC surplus, customer demand at the time of DTE's December, January and February system peaks is highly unlikely to have any significant impact on DTE's total need for production facility capacity. As a result, allocating demand allocated production facility costs to customer classes based on their demand at the time of those monthly system peaks would not be consistent with cost causation. In addition, shifting the allocation of these costs toward customer demand at the time of the MISO Winter monthly system peaks would necessarily involve shifting costs away from customer demand at the time of the Summer monthly system peaks -- the time when customer demand at the time of the monthly system peaks <u>does</u> impact DTE's total need for production capacity. This would create a cross subsidy and a price signal that would foster inefficient customer behavior.

[37]Jester Direct at 19.
[38]Exhibit AB-20 at lines 1, 2 and 12.

Given all of the above, MNSC witness Jester's proposal to change the demand allocation of DTE's current 4-CP 75-0-25 production facility cost allocator from the current 4-CP method to witness Jester's "weighted incremental share of production plant by season" method should be rejected and the current 4-CP method continued for the reasons I have previously discussed in this testimony. Also, as I earlier noted, given MNSC witness Jester's production facility cost rate design proposal is contingent on Commission adoption of one of his proposed changes to the demand portion DTE's production plant cost allocator, that proposal should be rejected as well.

III. Response to MNSC Distribution Rate Design Proposal

Q PLEASE BRIEFLY DESCRIBE MNSC WITNESS JESTER'S PROPOSAL TO CHANGE THE RATE DESIGN FOR DISTRIBUTION COSTS.

A Leveraging the direct testimony of MNSC witnesses Gard and Woolley with respect to transformer loss of life and the temperature impact on distribution facility ratings,[39] MSC witness Jester argues the proper basis of both cost of service and rate design of distribution costs is the degree of capacity utilization, not nominal loading and, thus, the rates should be seasonal. While he makes this argument, his requested relief is limited to asking the Commission to direct DTE to submit in its next rate case a seasonal approach to distribution rates reflecting that the relative utilization of the distribution system is seasonal.[40]

[39]Jester Direct at 23-26.
[40]Jester Direct at 44.

Q HOW DO YOU RESPOND?

A In general, utilization does not align with cost causation unless either the cost in question involves incurring a variable cost based on utilization or the utilization period being used is limited to demand in the specific hours that cause the utility to incur infrastructure costs. In this regard, just because the loss of life of a distribution transformer may be higher in certain seasons than others, it does not mean the allocation of all distribution costs should be based on seasonal utilization even if distribution equipment ratings are sensitive to ambient temperature. This said, given MNSC witness Jester has not requested the Commission to find in this proceeding that distribution rates be based on seasonal utilization, only that the Commission require certain information be filed by DTE in its next rate case filing, I will at this time simply reserve ABATE's right to respond to any proposal in future rate case proceedings that the Commission require DTE to adopt either a distribution class cost of service method, or a distribution rate design, that is based on seasonal utilization.

IV. Response to MEIU Proposal to Require DTE to Revise its Transmission Electrification Plan to Account for Societal Benefits

Q PLEASE BRIEFLY DESCRIBE MEIU WITNESS SHERMAN'S PROPOSAL TO REQUIRE DTE TO CHANGE ITS TRANSMISSION ELECTRIFICATION PLAN ("TEP") BENEFIT TO COST ANALYSIS ("BCA") TO ACCOUNT FOR SOCIETAL BENEFITS.

A MEIU witness Sherman presents extensive testimony that argues that the Commission should require DTE to account for societal benefits, including greenhouse gas and criteria pollutant emissions reductions, in its BCA for its TEP.[41] While ABATE would

[41]Sherman Direct at 24-36 and 64.

not object to the use of the SCT ("Societal Cost Test") for informational purposes as a sensitivity case, the Commission should not order the use of the SCT, or any other the inclusion of societal benefits, including greenhouse gas and criteria pollutant emissions, in DTE's base case BCA for its TEP. In addition, the Commission should not direct DTE to pursue or expand its TEP on the basis of societal benefits associated with avoided transportation emissions, as that would amount to mandating electric ratepayers to subsidize the cost of providing the claimed societal benefits. To the extent the Commission grants the request of MEIU witness Sherman, it should be limited to the provision of a sensitivity case for the BCA for the DTE TEP.

Q DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A Yes, it does.

Michigan Public Service Commission
ABATE
DTE Electric System Demand Tests

DTE Electric Company
FERC Tests for Coincident Peak Allocation

							TEST 1	TEST 2	TEST 3	TEST 4
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
Line	Year	CP	Peak	Peak as % Single High	Ave Off Peak	Off Peak as % of Single High (e)/(b) 1CP	Difference (d) - (f)	Lowest Peak as % of High	Off-Peak Month Higher than Peak?	Average of 12 Peaks as % of High
1	2018	1CP	11,418					55%		
2		3 CP	11,192	98%	7,917	69%	29%		No	
3		4 CP	11,248	99%	7,479	66%	33%		No	
4		12 CP	8,735							77%
5	2019	1CP	10,630					58%		
6		3 CP	10,207	96%	7,261	68%	28%		No	
7		4 CP	9,995	94%	6,998	66%	28%		No	
8		12 CP	7,997							75%
9	2020	1CP	11,005					45%		
10		3 CP	10,593	96%	6,798	62%	34%		No	
11		4 CP	10,165	92%	6,538	59%	33%		No	
12		12 CP	7,747							70%
13	2021	1CP	10,992					55%		
14		3 CP	10,721	98%	7,057	64%	33%		No	
15		4 CP	10,233	93%	6,844	62%	31%		No	
16		12 CP	7,973							73%
17	2022	1CP	10,933					54%		
18		3 CP	10,858	99%	6,977	64%	35%		No	
19		4 CP	10,305	94%	6,768	62%	32%		No	
20		12 CP	7,947							73%
21	2023	1CP	10,340					59%		
22		3 CP	9,417	91%	7,173	66%	25%		No	
23		4 CP	9,648	93%	6,777	62%	31%		No	
24		12 CP	7,734							75%
25	Average	3 CP					31%			
26	Average	4 CP					31%			
27	Average							54%	None	74%
28	Precedent for 12 CP						18 to 19%	70% range	Yes	Min 81%
29	Precedent for 3 or 4 CP						16 to 31%	below 60%	No	

Michigan Public Service Commission
ABATE
DTE Electric System Demand Tests

DTE Electric Company Monthly Peaks (MW)
Annual Report to the MPSC (Form P-521, page 401b, column d)

Line		2018	2019	2020	2021	2022	2023
1	January	7,358	7,514	6,664	6,537	6,825	6,402
2	February	6,956	6,910	6,621	6,679	6,569	6,560
3	March	6,609	6,934	6,155	6,265	6,225	6,124
4	April	6,322	6,153	4,919	6,001	6,032	6,288
5	May	10,361	6,804	8,968	8,770	9,681	8,477
6	June	11,287	9,879	10,060	10,321	10,933	9,029
7	July	11,317	10,630	11,005	10,850	10,839	9,907
8	August	10,971	10,112	10,715	10,992	10,802	9,315
9	September	11,418	9,359	8,878	8,768	8,647	10,340
10	October	8,277	7,890	5,897	7,517	5,921	7,634
11	November	6,954	6,731	6,446	6,329	6,289	6,399
12	December	6,995	7,050	6,636	6,651	6,604	6,334
13	12 Max	11,418	10,630	11,005	10,992	10,933	10,340
14	3 CP	11,192	10,207	10,593	10,721	10,858	9,417
15	4 CP	11,248	9,995	10,165	10,233	10,305	9,648
16	12 CP	8,735	7,997	7,747	7,973	7,947	7,734
17	3 Off Peak	7,917	7,261	6,798	7,057	6,977	7,173
18	4 Off Peak	7,479	6,998	6,538	6,844	6,768	6,777
19	12 Min	6,322	6,153	4,919	6,001	5,921	6,124
20	4 Min	10,971	9,359	8,878	8,768	8,647	9,029
21	3 Min	10,971	9,879	10,060	10,321	10,802	9,029
22	Off-Peak max	10,361	7,890	8,968	8,770	9,681	8,477

DTE Electric Company

Historical Monthly Maximum Coincident Peaks

MW

Line	Month	2014 (1)	2015 (2)	2016 (3)	2017 (4)	2018 (5)	2019 (6)	2020 (7)	2021 (8)	2022 (9)	2023 (10)	Average (11)	Percent of Highest Peak (12)
1	January	7,685	7,594	7,084	7,074	7,358	7,514	6,664	6,537	6,825	6,402	7,074	66%
2	February	7,322	7,398	6,833	6,828	6,956	6,910	6,621	6,679	6,569	6,560	6,868	64%
3	March	7,165	6,978	6,978	6,626	6,609	6,934	6,155	6,265	6,225	6,124	6,606	62%
4	April	6,370	6,334	6,320	6,275	6,322	6,153	4,919	6,001	6,032	6,288	6,101	57%
5	May	8,165	8,258	8,812	8,368	10,361	6,804	8,968	8,770	9,681	8,477	8,666	81%
6	**June**	**10,014**	**9,131**	**10,475**	**10,499**	**11,287**	**9,879**	**10,060**	**10,321**	**10,933**	**9,029**	**10,163**	**95%**
7	**July**	**10,314**	**10,651**	**11,269**	**10,554**	**11,317**	**10,630**	**11,005**	**10,850**	**10,839**	**9,907**	**10,734**	**100%**
8	**August**	**10,510**	**10,331**	**11,422**	**9,702**	**10,971**	**10,112**	**10,715**	**10,992**	**10,802**	**9,315**	**10,487**	**98%**
9	**September**	**10,939**	**10,660**	**10,888**	**10,260**	**11,418**	**9,359**	**8,878**	**8,768**	**8,647**	**10,340**	**10,016**	**93%**
10	October	6,390	6,268	7,335	7,277	8,277	7,890	5,897	7,517	5,921	7,634	7,041	66%
11	November	7,152	6,651	6,591	6,446	6,954	6,731	6,446	6,329	6,289	6,399	6,599	61%
12	December	7,125	6,854	7,404	7,177	6,995	7,050	6,636	6,651	6,604	6,334	6,883	64%

Source: FERC Form 1

Monthly Zonal Non-Coincident and MISO Coincident Peak (Date and Hour Ending EST)

Seasonal Peak (Highlighted)

		LRZ										MISO
Month/Year	Season	1	2	3	4	5	6	7	8	9	10	
05/2024		05/20/24 HE 20	05/23/24 HE 14	05/20/24 HE 18	05/19/24 HE 18	05/21/24 HE 17	05/21/24 HE 17	05/21/24 HE 17	05/20/24 HE 18	05/27/24 HE 17	05/27/24 HE 16	5/21/24 HE 17
04/2024	Spring	04/03/24 HE 8	04/02/24 HE 14	04/03/24 HE 10	04/04/24 HE 9	04/15/24 HE 18	04/04/24 HE 9	04/29/24 HE 13	04/30/24 HE 19	04/30/24 HE 18	04/30/24 HE 18	04/30/24 HE 18
03/2024		03/27/24 HE 8	03/18/24 HE 11	03/18/24 HE 9	03/11/24 HE 8	03/19/24 HE 8	03/19/24 HE 7	03/21/24 HE 8	03/19/24 HE 8	03/14/24 HE 17	03/19/24 HE 8	03/19/24 HE 8
02/2024		02/28/24 HE 20	02/28/24 HE 20	02/28/24 HE 9	02/16/24 HE 20	02/17/24 HE 9	02/19/24 HE 8	02/15/24 HE 11	02/13/24 HE 9	02/19/24 HE 9	02/19/24 HE 9	02/19/24 HE 9
01/2024	Winter	01/15/24 HE 19	01/16/24 HE 19	01/15/24 HE 19	01/15/24 HE 19	01/14/24 HE 19	01/15/24 HE 10	01/16/24 HE 19	01/17/24 HE 8	01/17/24 HE 9	01/17/24 HE 9	01/16/24 HE 10
12/2023		12/11/23 HE 19	12/18/23 HE 19	12/18/23 HE 19	12/11/23 HE 9	12/19/23 HE 9	12/19/23 HE 8	12/18/23 HE 19	12/19/23 HE 9	12/29/23 HE 9	12/11/23 HE 9	12/19/23 HE 9
11/2023		11/27/23 HE 19	11/27/23 HE 19	11/28/23 HE 9	11/27/23 HE 20	11/28/23 HE 9	11/28/23 HE 8	11/27/23 HE 18	11/27/23 HE 9	11/29/23 HE 8	11/29/23 HE 9	11/28/23 HE 9
10/2023	Fall	10/02/23 HE 18	10/02/23 HE 17	10/02/23 HE 17	10/01/23 HE 18	10/02/23 HE 17	10/02/23 HE 17	10/03/23 HE 16	10/09/23 HE 17	10/01/23 HE 17	10/03/23 HE 17	10/02/23 HE 17
09/2023		09/04/23 HE 19	09/05/23 HE 15	09/04/23 HE 18	09/03/23 HE 18	09/04/23 HE 17	09/05/23 HE 16	09/05/23 HE 16	09/06/23 HE 15	09/07/23 HE 16	09/07/23 HE 15	09/05/23 HE 17
08/2023		08/22/23 HE 19	08/23/23 HE 16	08/23/23 HE 18	08/24/23 HE 17	08/25/23 HE 17	08/24/23 HE 18	08/03/23 HE 16	08/25/23 HE 16	08/23/23 HE 17	08/24/23 HE 16	08/23/23 HE 17
07/2023	Summer	07/27/23 HE 17	07/27/23 HE 17	07/26/23 HE 18	07/27/23 HE 17	07/28/23 HE 17	07/28/23 HE 18	07/05/23 HE 16	07/28/23 HE 17	07/31/23 HE 16	07/27/23 HE 16	07/27/23 HE 17
06/2023		06/21/23 HE 19	06/29/23 HE 17	06/22/23 HE 16	06/24/23 HE 18	06/30/23 HE 17	06/01/23 HE 16	06/02/23 HE 16	06/29/23 HE 19	06/29/23 HE 16	06/30/23 HE 15	06/30/23 HE 17
05/2023		05/31/23 HE 19	05/31/23 HE 15	05/31/23 HE 16	05/31/23 HE 17	05/31/23 HE 18	05/31/23 HE 16	05/31/23 HE 16	05/31/23 HE 15	05/19/23 HE 17	05/15/23 HE 16	05/31/23 HE 17
04/2023	Spring	04/04/23 HE 18	04/13/23 HE 16	04/06/23 HE 8	04/17/23 HE 9	04/04/23 HE 18	04/17/23 HE 10	04/18/23 HE 10	04/19/23 HE 18	04/03/23 HE 17	04/05/23 HE 14	04/04/23 HE 17
03/2023		03/29/23 HE 8	03/14/23 HE 8	03/14/23 HE 8	03/13/23 HE 20	03/20/23 HE 8	03/20/23 HE 8	03/14/23 HE 8	03/20/23 HE 8	03/20/23 HE 8	03/20/23 HE 8	03/20/23 HE 8
02/2023		02/03/23 HE 11	02/03/23 HE 10	02/28/23 HE 13	02/03/23 HE 9	02/01/23 HE 9	02/03/23 HE 8	02/03/23 HE 11	02/01/23 HE 11	02/03/23 HE 9	02/04/23 HE 9	02/03/23 HE 9
01/2023	Winter	01/31/23 HE 9	01/31/23 HE 10	01/31/23 HE 9	01/26/23 HE 20	01/31/23 HE 9	01/31/23 HE 9	01/31/23 HE 10	01/31/23 HE 14	01/27/23 HE 9	01/27/23 HE 9	01/31/23 HE 20
12/2022		12/22/22 HE 19	12/22/22 HE 19	12/22/22 HE 19	12/23/22 HE 19	12/23/22 HE 19	12/23/22 HE 19	12/19/22 HE 18	12/23/22 HE 8	12/23/22 HE 10	12/23/22 HE 21	12/23/22 HE 19
11/2022		11/30/22 HE 19	11/30/22 HE 19	11/30/22 HE 19	11/19/22 HE 21	11/17/22 HE 9	11/21/22 HE 8	11/30/22 HE 18	11/17/22 HE 8	11/18/22 HE 8	11/18/22 HE 8	11/18/22 HE 9
10/2022	Fall	10/18/22 HE 8	10/04/22 HE 14	10/19/22 HE 8	10/20/22 HE 8	10/19/22 HE 8	10/20/22 HE 8	10/20/22 HE 10	10/06/22 HE 17	10/12/22 HE 16	10/12/22 HE 15	10/19/22 HE 8
09/2022		09/01/22 HE 19	09/01/22 HE 17	09/20/22 HE 17	09/20/22 HE 17	09/20/22 HE 17	09/21/22 HE 16	09/02/22 HE 16	09/20/22 HE 17	09/22/22 HE 17	09/21/22 HE 16	09/01/22 HE 17
08/2022		08/02/22 HE 19	08/02/22 HE 18	08/02/22 HE 18	08/06/22 HE 17	08/01/22 HE 18	08/08/22 HE 16	08/03/22 HE 15	08/15/22 HE 16	08/16/22 HE 17	08/15/22 HE 17	08/03/22 HE 15
07/2022	Summer	07/18/22 HE 18	07/18/22 HE 17	07/05/22 HE 17	07/21/22 HE 17	07/05/22 HE 16	07/05/22 HE 17	07/19/22 HE 16	07/26/22 HE 16	07/20/22 HE 17	07/21/22 HE 16	07/21/22 HE 17
06/2022		06/20/22 HE 18	06/21/22 HE 17	06/21/22 HE 16	06/16/22 HE 19	06/16/22 HE 18	06/16/22 HE 17	06/15/22 HE 17	06/22/22 HE 17	06/24/22 HE 16	06/23/22 HE 16	06/21/22 HE 17
05/2022		05/12/22 HE 19	05/12/22 HE 17	05/12/22 HE 17	05/12/22 HE 17	05/12/22 HE 17	05/31/22 HE 16	05/31/22 HE 16	05/12/22 HE 18	05/18/22 HE 17	05/19/22 HE 17	05/12/22 HE 17
04/2022	Spring	04/18/22 HE 9	04/18/22 HE 12	04/01/22 HE 8	04/08/22 HE 10	04/01/22 HE 8	04/19/22 HE 7	04/04/22 HE 11	04/01/22 HE 8	04/30/12 HE 17	04/30/22 HE 17	04/01/22 HE 8
03/2022		03/09/22 HE 21	03/10/22 HE 20	03/10/22 HE 12	03/11/22 HE 22	03/12/22 HE 9	03/12/22 HE 9	03/03/22 HE 10	03/11/22 HE 20	03/12/22 HE 10	03/13/22 HE 9	03/12/22 HE 10
02/2022		02/22/22 HE 20	02/02/22 HE 19	02/03/22 HE 9	02/03/22 HE 12	02/23/22 HE 20	02/14/22 HE 8	02/04/22 HE 11	02/04/22 HE 21	02/05/22 HE 9	02/04/22 HE 22	02/04/22 HE 10
01/2022	Winter	01/07/22 HE 19	01/10/22 HE 19	01/06/22 HE 19	01/06/22 HE 19	01/21/22 HE 9	01/07/22 HE 9	01/10/22 HE 19	01/21/22 HE 9	01/22/22 HE 9	01/23/22 HE 9	01/21/22 HE 9
12/2021		12/20/21 HE 19	12/07/21 HE 19	12/06/21 HE 19	12/06/21 HE 19	12/07/21 HE 19	12/07/21 HE 19	12/07/21 HE 19	12/20/21 HE 9	12/22/21 HE 9	12/22/21 HE 10	12/22/21 HE 9
11/2021		11/22/21 HE 19	11/29/21 HE 19	11/22/21 HE 10	11/24/21 HE 23	11/23/21 HE 9	11/23/21 HE 8	11/29/21 HE 19	11/19/21 HE 9	11/29/21 HE 9	11/29/21 HE 9	11/23/21 HE 9
10/2021	Fall	10/06/21 HE 20	10/01/21 HE 16	10/01/21 HE 14	10/01/21 HE 16	10/10/21 HE 17	10/11/21 HE 15	10/11/21 HE 15	10/08/21 HE 17	10/15/21 HE 16	10/15/21 HE 15	10/01/21 HE 16
09/2021		09/16/21 HE 18	09/20/21 HE 17	09/27/21 HE 17	09/17/21 HE 16	09/14/21 HE 16	09/14/21 HE 16	09/14/21 HE 14	09/01/21 HE 16	09/20/21 HE 17	09/01/21 HE 16	09/20/21 HE 17
08/2021		08/19/21 HE 16	08/10/21 HE 16	08/10/21 HE 16	08/27/21 HE 16	08/25/21 HE 17	08/24/21 HE 17	08/24/21 HE 16	08/10/21 HE 16	08/23/21 HE 17	08/10/21 HE 17	08/24/21 HE 16
07/2021	Summer	07/27/21 HE 18	07/06/21 HE 15	07/28/21 HE 17	07/23/21 HE 17	07/29/21 HE 16	07/29/21 HE 16	07/06/21 HE 15	07/27/21 HE 16	07/30/21 HE 16	07/29/21 HE 15	07/28/21 HE 17
06/2021		06/07/21 HE 18	06/08/21 HE 17	06/17/21 HE 17	06/18/21 HE 16	06/18/21 HE 16	06/29/21 HE 15	06/09/21 HE 16	06/25/21 HE 16	06/14/21 HE 17	06/14/21 HE 17	06/11/21 HE 17
05/2021		05/24/21 HE 18	05/25/21 HE 15	05/24/21 HE 17	05/24/21 HE 17	05/26/21 HE 18	05/24/21 HE 17	05/25/21 HE 15	05/27/21 HE 16	05/27/21 HE 17	05/27/21 HE 17	05/25/21 HE 16
04/2021	Spring	04/01/21 HE 8	04/07/21 HE 14	04/27/21 HE 14	04/01/21 HE 8	04/01/21 HE 8	04/01/21 HE 8	04/01/21 HE 10	04/14/21 HE 18	04/29/21 HE 17	04/28/21 HE 16	04/01/21 HE 8
03/2021		03/01/21 HE 10	03/01/21 HE 20	03/01/21 HE 20	03/15/21 HE 11	03/02/21 HE 9	03/02/21 HE 8	03/01/21 HE 20	03/02/21 HE 9	03/03/21 HE 9	03/02/21 HE 21	03/02/21 HE 9
02/2021		02/11/21 HE 20	02/15/21 HE 19	02/16/21 HE 10	02/12/21 HE 20	02/15/21 HE 20	02/17/21 HE 8	02/15/21 HE 19	02/15/21 HE 12	02/14/21 HE 21	02/15/21 HE 20	02/15/21 HE 20
01/2021	Winter	01/27/21 HE 10	01/04/21 HE 19	01/28/21 HE 10	01/28/21 HE 9	01/28/21 HE 9	01/29/21 HE 9	01/28/21 HE 19	01/12/21 HE 9	01/12/21 HE 9	01/11/21 HE 21	01/29/21 HE 9
12/2020		12/29/20 HE 19	12/15/20 HE 19	12/14/20 HE 19	12/18/20 HE 19	12/25/20 HE 9	12/15/20 HE 9	12/16/20 HE 19	12/01/20 HE 8	12/18/20 HE 9	12/18/20 HE 9	12/16/20 HE 19

11/2020		11/12/20 HE 19	11/30/20 HE 19	11/30/20 HE 20	11/30/20 HE 19	11/30/20 HE 19	11/30/20 HE 19	11/30/20 HE 19	11/30/20 HE 21	11/30/20 HE 21	11/30/20 HE 23	11/30/20 HE 20
10/2020	Fall	10/27/20 HE 9	10/26/20 HE 12	10/09/20 HE 16	10/08/20 HE 17	10/09/20 HE 17	10/30/20 HE 8	10/27/20 HE 11	10/21/20 HE 16	10/21/20 HE 17	10/12/20 HE 16	10/22/20 HE 17
09/2020		09/23/20 HE 18	09/02/20 HE 16	09/02/20 HE 17	09/06/20 HE 18	09/07/20 HE 18	09/03/20 HE 16	09/01/20 HE 15	09/09/20 HE 16	09/10/20 HE 17	09/03/20 HE 17	09/03/20 HE 16
08/2020		08/26/20 HE 17	08/26/20 HE 16	08/24/20 HE 17	08/27/20 HE 15	08/10/20 HE 15	08/24/20 HE 17	08/10/20 HE 16	08/10/20 HE 16	08/16/20 HE 17	08/11/20 HE 17	08/24/20 HE 17
07/2020	Summer	07/24/20 HE 18	07/07/20 HE 15	07/08/20 HE 15	07/09/20 HE 17	07/09/20 HE 17	07/09/20 HE 16	07/09/20 HE 14	07/20/20 HE 14	07/13/20 HE 16	07/20/20 HE 16	07/09/20 HE 15
06/2020		06/08/20 HE 18	06/30/20 HE 17	06/08/20 HE 16	06/26/20 HE 17	06/26/20 HE 17	06/29/20 HE 15	06/30/20 HE 17	06/30/20 HE 17	06/30/20 HE 17	06/30/20 HE 16	06/30/20 HE 17
05/2020		05/26/20 HE 18	05/27/20 HE 15	05/26/20 HE 14	05/28/20 HE 14	05/26/20 HE 16	05/26/20 HE 17	05/26/20 HE 17	05/22/20 HE 14	05/22/20 HE 16	05/22/20 HE 16	05/26/20 HE 17
04/2020	Spring	04/03/20 HE 13	04/01/20 HE 11	04/03/20 HE 12	04/08/20 HE 18	04/08/20 HE 18	04/16/20 HE 8	04/22/20 HE 12	04/08/20 HE 18	04/09/20 HE 17	04/09/20 HE 16	04/08/20 HE 18
03/2020		03/10/20 HE 8	03/16/20 HE 12	03/10/20 HE 8	03/06/20 HE 9	03/16/20 HE 11	03/06/20 HE 11	03/06/20 HE 11	03/16/20 HE 11	03/27/20 HE 16	03/27/20 HE 17	03/06/20 HE 9
02/2020		02/13/20 HE 9	02/13/20 HE 20	02/13/20 HE 20	02/13/20 HE 20	02/14/20 HE 9	02/14/20 HE 8	02/14/20 HE 10	02/14/20 HE 8	02/07/20 HE 8	02/21/20 HE 9	02/14/20 HE 9
01/2020	Winter	01/16/20 HE 9	01/16/20 HE 19	01/21/20 HE 9	01/19/20 HE 20	01/20/20 HE 20	01/20/20 HE 9	01/08/20 HE 19	01/21/20 HE 8	01/21/20 HE 9	01/21/20 HE 8	01/21/20 HE 9
12/2019		12/10/19 HE 19	12/18/19 HE 19	12/10/19 HE 19	12/19/19 HE 9	12/16/19 HE 19	12/19/19 HE 8	12/18/19 HE 19	12/11/19 HE 8	12/18/19 HE 8	12/19/19 HE 9	12/19/19 HE 9
11/2019		11/11/19 HE 19	11/13/19 HE 19	11/12/19 HE 9	11/15/19 HE 8	11/12/19 HE 9	11/13/19 HE 8	11/13/19 HE 19	11/13/19 HE 8	11/13/19 HE 8	11/13/19 HE 8	11/13/19 HE 9
10/2019	Fall	10/30/19 HE 8	10/01/19 HE 11	10/01/19 HE 15	10/01/19 HE 17	10/01/19 HE 17	10/01/19 HE 16	10/01/19 HE 15	10/01/19 HE 17	10/02/19 HE 17	10/02/19 HE 17	10/01/19 HE 17
09/2019		09/17/19 HE 18	09/11/19 HE 14	09/16/19 HE 16	09/12/19 HE 17	09/16/19 HE 17	09/12/19 HE 16	09/11/19 HE 13	09/04/19 HE 17	09/06/19 HE 17	09/13/19 HE 15	09/11/19 HE 17
08/2019		08/06/19 HE 18	08/05/19 HE 16	08/07/19 HE 17	08/13/19 HE 17	08/12/19 HE 18	08/19/19 HE 17	08/05/19 HE 16	08/20/19 HE 17	08/12/19 HE 17	08/13/19 HE 16	08/05/19 HE 16
07/2019	Summer	07/15/19 HE 16	07/19/19 HE 16	07/19/19 HE 17	07/19/19 HE 16	07/19/19 HE 17	07/19/19 HE 15	07/19/19 HE 14	07/09/19 HE 17	07/09/19 HE 17	07/09/19 HE 16	07/19/19 HE 16
06/2019		06/07/19 HE 17	06/27/19 HE 15	06/29/19 HE 18	06/28/19 HE 15	06/05/19 HE 17	06/27/19 HE 17	06/28/19 HE 15	06/21/19 HE 17	06/19/19 HE 17	06/21/19 HE 16	06/27/19 HE 16
05/2019		05/31/19 HE 18	05/31/19 HE 16	05/16/19 HE 17	05/25/19 HE 18	05/28/19 HE 17	05/28/19 HE 16	05/28/19 HE 14	05/23/19 HE 17	05/28/19 HE 17	05/28/19 HE 17	05/31/19 HE 16
04/2019	Spring	04/11/19 HE 12	04/11/19 HE 12	04/02/19 HE 10	04/17/19 HE 21	04/01/19 HE 8	04/01/19 HE 7	04/01/19 HE 9	04/01/19 HE 8	04/30/19 HE 17	04/30/19 HE 17	04/01/19 HE 8
03/2019		03/04/19 HE 9	03/04/19 HE 20	03/04/19 HE 10	03/04/19 HE 21	03/04/19 HE 9	03/05/19 HE 8	03/05/19 HE 11	03/04/19 HE 9	03/06/19 HE 8	03/06/19 HE 8	03/04/19 HE 20
02/2019		02/07/19 HE 20	02/01/19 HE 10	02/08/19 HE 10	02/08/19 HE 8	02/08/19 HE 9	02/08/19 HE 9	02/01/19 HE 10	02/08/19 HE 9	02/08/19 HE 21	02/08/19 HE 21	02/08/19 HE 10
01/2019	Winter	01/29/19 HE 20	01/31/19 HE 19	01/30/19 HE 20	01/25/19 HE 9	01/30/19 HE 9	01/31/19 HE 9	01/30/19 HE 19	01/31/19 HE 9	01/24/19 HE 9	01/30/19 HE 9	01/30/19 HE 20
12/2018		12/06/18 HE 19	12/06/18 HE 19	12/07/18 HE 9	12/06/18 HE 19	12/10/18 HE 9	12/11/18 HE 8	12/10/18 HE 19	12/11/18 HE 8	12/11/18 HE 8	12/11/18 HE 9	12/11/18 HE 9
11/2018		11/12/18 HE 19	11/27/18 HE 19	11/12/18 HE 20	11/15/18 HE 19	11/27/18 HE 9	11/27/18 HE 19	11/28/18 HE 18	11/15/18 HE 9	11/15/18 HE 8	11/14/18 HE 20	11/13/18 HE 20
10/2018	Fall	10/29/18 HE 19	10/09/18 HE 14	10/03/18 HE 17	10/03/18 HE 16	10/03/18 HE 17	10/08/18 HE 16	10/09/18 HE 16	10/03/18 HE 17	10/04/18 HE 16	10/04/18 HE 16	10/03/18 HE 17
09/2018		09/16/18 HE 18	09/04/18 HE 16	09/17/18 HE 16	09/20/18 HE 16	09/20/18 HE 17	09/04/18 HE 16	09/05/18 HE 16	09/20/18 HE 16	09/17/18 HE 16	09/19/18 HE 17	09/04/18 HE 16
08/2018		08/13/18 HE 18	08/13/18 HE 17	08/09/18 HE 17	08/28/18 HE 16	08/28/18 HE 17	08/28/18 HE 16	08/28/18 HE 17	08/07/18 HE 17	08/21/18 HE 17	08/15/18 HE 16	08/27/18 HE 16
07/2018	Summer	07/12/18 HE 17	07/13/18 HE 15	07/12/18 HE 16	07/10/18 HE 15	07/05/18 HE 17	07/10/18 HE 15	07/05/18 HE 16	07/19/18 HE 17	07/20/18 HE 17	07/20/18 HE 17	07/13/18 HE 17
06/2018		06/29/18 HE 17	06/29/18 HE 17	06/18/18 HE 16	06/18/18 HE 17	06/18/18 HE 16	06/18/18 HE 15	06/18/18 HE 16	06/28/18 HE 16	06/28/18 HE 17	06/28/18 HE 17	06/29/18 HE 17
05/2018		05/29/18 HE 15	05/29/18 HE 17	05/31/18 HE 17	05/28/18 HE 17	05/30/18 HE 17	05/29/18 HE 14	05/29/18 HE 16	05/30/18 HE 18	05/30/18 HE 17	05/30/18 HE 16	05/29/18 HE 16
04/2018	Spring	04/06/18 HE 8	04/03/18 HE 11	04/04/18 HE 8	04/04/18 HE 9	04/02/18 HE 10	04/05/18 HE 7	04/04/18 HE 10	04/07/18 HE 12	04/03/18 HE 17	04/03/18 HE 17	04/05/18 HE 8
03/2018		03/05/18 HE 20	03/05/18 HE 20	03/05/18 HE 20	03/14/18 HE 8	03/14/18 HE 8	03/09/18 HE 8	03/08/18 HE 20	03/13/18 HE 8	03/19/18 HE 17	03/08/18 HE 8	03/14/18 HE 8
02/2018		02/05/18 HE 20	02/05/18 HE 20	02/02/18 HE 9	02/05/18 HE 9	02/05/18 HE 9	02/05/18 HE 8	02/05/18 HE 19	02/08/18 HE 8	02/08/18 HE 9	02/08/18 HE 9	02/08/18 HE 9
01/2018	Winter	01/11/18 HE 20	01/04/18 HE 19	01/15/18 HE 20	01/16/18 HE 10	01/16/18 HE 10	01/02/18 HE 9	01/04/18 HE 19	01/17/18 HE 9	01/17/18 HE 9	01/18/18 HE 9	01/17/18 HE 9
12/2017		12/27/17 HE 19	12/27/17 HE 19	12/27/17 HE 19	12/27/17 HE 19	12/31/17 HE 20	12/27/17 HE 9	12/13/17 HE 19	12/28/17 HE 9	12/08/17 HE 20	12/31/17 HE 22	12/27/17 HE 20
11/2017		11/21/17 HE 19	11/09/17 HE 19	11/09/17 HE 20	11/10/17 HE 10	11/22/17 HE 9	11/20/17 HE 8	11/09/17 HE 19	11/20/17 HE 9	11/06/17 HE 17	11/20/17 HE 10	11/06/17 HE 19
10/2017	Fall	10/31/17 HE 8	10/03/17 HE 20	10/03/17 HE 14	10/09/17 HE 17	10/02/17 HE 17	10/03/17 HE 17	10/04/17 HE 13	10/09/17 HE 15	10/13/17 HE 17	10/09/17 HE 16	10/09/17 HE 16
09/2017		09/22/17 HE 17	09/22/17 HE 15	09/22/17 HE 16	09/22/17 HE 16	09/20/17 HE 17	09/21/17 HE 16	09/26/17 HE 16	09/21/17 HE 16	09/22/17 HE 16	09/21/17 HE 17	09/22/17 HE 16
08/2017		08/01/17 HE 16	08/01/17 HE 16	08/01/17 HE 17	08/15/17 HE 17	08/21/17 HE 17	08/16/17 HE 16	08/21/17 HE 13	08/21/17 HE 17	08/18/17 HE 17	08/22/17 HE 17	08/01/17 HE 16
07/2017	Summer	07/17/17 HE 18	07/20/17 HE 17	07/20/17 HE 17	07/21/17 HE 16	07/21/17 HE 16	07/21/17 HE 16	07/19/17 HE 17	07/20/17 HE 17	07/20/17 HE 17	07/20/17 HE 17	07/20/17 HE 17
06/2017		06/13/17 HE 18	06/12/17 HE 15	06/13/17 HE 17	06/13/17 HE 17	06/13/17 HE 17	06/12/17 HE 18	06/12/17 HE 16	06/14/17 HE 18	06/19/17 HE 17	06/15/17 HE 16	06/12/17 HE 16
05/2017		05/16/17 HE 17	05/17/17 HE 14	05/16/17 HE 16	05/18/17 HE 17	05/18/17 HE 18	05/18/17 HE 16	05/18/17 HE 14	05/31/17 HE 17	05/27/17 HE 17	05/18/17 HE 17	05/16/17 HE 17
04/2017	Spring	04/27/17 HE 11	04/26/17 HE 12	04/05/17 HE 12	04/19/17 HE 21	04/19/17 HE 17	04/26/17 HE 16	04/06/17 HE 10	04/19/17 HE 17	04/28/17 HE 16	04/29/17 HE 15	04/19/17 HE 17
03/2017		03/14/17 HE 8	03/01/17 HE 20	03/15/17 HE 8	03/15/17 HE 8	03/15/17 HE 8	03/16/17 HE 7	03/15/17 HE 7	03/15/17 HE 8	03/28/17 HE 17	03/15/17 HE 9	03/15/17 HE 8
02/2017		02/09/17 HE 9	02/02/17 HE 20	02/09/17 HE 9	02/09/17 HE 9	02/09/17 HE 9	02/09/17 HE 8	02/02/17 HE 20	02/09/17 HE 9	02/16/17 HE 9	02/04/17 HE 10	02/02/17 HE 20
01/2017	Winter	01/04/17 HE 19	01/05/17 HE 19	01/06/17 HE 9	01/06/17 HE 19	01/06/17 HE 9	01/06/17 HE 9	01/05/17 HE 19	01/06/17 HE 11	01/07/17 HE 10	01/08/17 HE 10	01/06/17 HE 19

12/2016		12/14/16 HE 19	12/19/16 HE 19	12/15/16 HE 19	12/19/16 HE 10	12/19/16 HE 9	12/19/16 HE 9	12/19/16 HE 19	12/19/16 HE 9	12/19/16 HE 9	12/19/16 HE 10	12/19/16 HE 9
11/2016		11/22/16 HE 19	11/30/16 HE 19	11/30/16 HE 19	11/30/16 HE 19	11/30/16 HE 19	11/21/16 HE 8	11/21/16 HE 19	11/01/16 HE 17	11/03/16 HE 17	11/21/16 HE 9	11/21/16 HE 9
10/2016	Fall	10/17/16 HE 14	10/17/16 HE 19	10/17/16 HE 17	10/17/16 HE 16	10/17/16 HE 16	10/06/16 HE 17	10/06/16 HE 14	10/05/16 HE 17	10/05/16 HE 17	10/05/16 HE 17	10/17/16 HE 16
09/2016		09/06/16 HE 17	09/06/16 HE 16	09/06/16 HE 16	09/06/16 HE 17	09/07/16 HE 17	09/07/16 HE 16	09/06/16 HE 16	09/07/16 HE 16	09/01/16 HE 17	09/01/16 HE 16	09/06/16 HE 17
08/2016		08/03/16 HE 18	08/10/16 HE 17	08/10/16 HE 16	08/11/16 HE 17	08/11/16 HE 16	08/11/16 HE 16	08/11/16 HE 15	08/02/16 HE 17	08/04/16 HE 16	08/03/16 HE 17	08/10/16 HE 16
07/2016	Summer	07/20/16 HE 17	07/22/16 HE 17	07/21/16 HE 17	07/21/16 HE 17	07/21/16 HE 17	07/21/16 HE 15	07/22/16 HE 16	07/21/16 HE 15	07/07/16 HE 17	07/21/16 HE 16	07/21/16 HE 16
06/2016		06/10/16 HE 14	06/20/16 HE 14	06/15/16 HE 17	06/20/16 HE 17	06/16/16 HE 17	06/20/16 HE 15	06/20/16 HE 16	06/16/16 HE 17	06/17/16 HE 17	06/16/16 HE 16	06/20/16 HE 16
05/2016		05/24/16 HE 17	05/26/16 HE 17	05/26/16 HE 15	05/31/16 HE 17	05/31/16 HE 18	05/31/16 HE 15	05/26/16 HE 16	05/26/16 HE15	05/31/16 HE 16	05/26/16 HE 16	05/31/16 HE 16
04/2016	Spring	04/08/16 HE 10	04/18/16 HE 14	04/18/16 HE 13	04/25/16 HE 16	04/25/16 HE 18	04/05/16 HE 7	04/06/16 HE 10	04/27/16 HE 18	04/26/16 HE 17	04/28/16 HE 17	04/26/16 HE 14
03/2016		03/01/16 HE 9	03/01/16 HE 20	03/01/16 HE 21	03/01/16 HE 20	03/02/16 HE 9	03/01/16 HE 21	03/01/16 HE 20	03/21/16 HE 8	03/21/16 HE 8	03/21/16 HE 8	03/01/16 HE 21
02/2016		02/08/16 HE 20	02/10/16 HE 20	02/11/16 HE 9	02/09/16 HE 20	02/10/16 HE 9	02/10/16 HE 8	02/10/16 HE 20	02/10/16 HE 8	02/05/16 HE 9	02/10/16 HE 8	02/10/16 HE 9
01/2016		01/11/16 HE 19	01/18/16 HE 19	01/18/16 HE 20	01/18/16 HE 20	01/18/16 HE 9	01/19/16 HE 8	01/11/16 HE 19	01/11/16 HE 9	01/11/16 HE 9	01/19/16 HE 8	01/19/16 HE 9

1. All times are Hour-Ending, MISO-time (Eastern Standard Time)
2. Based on hourly integrated data from RT Settled Load data source
3. Data is up to date at time of release (June 2024)

Source: https://cdn.misoenergy.org/Historical%20Monthly_Seasonal%20Peak%20Dates%20and%20Times%20MISO%20LRZ_Settled%20Load%20(Spring%202024)636872.xlsx (as accessed on August 12, 2024)

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

Rebuttal Testimony and Exhibits of

Brian C. Andrews

On behalf of

Association of Businesses Advocating Tariff Equity

August 16, 2024

BRUBAKER & ASSOCIATES, INC.

Project 11638

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

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Rebuttal Testimony of Brian C. Andrews

I. Introduction

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Brian C. Andrews. 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 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"

or "Company"). They primarily take service under DTE Rider D8, Rate D11, Rider 3 and/or Rider 10.

Q WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A My Rebuttal Testimony responds to Michigan Public Service Commission Staff ("Staff") witness Mark J. Pung's testimony. Specifically, I will respond to his proposal to change the allocation of DTE's purchased capacity costs

Q PLEASE BRIEFLY SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS IN THIS PROCEEDING.

A My conclusions and recommendations are as follows:

1. I recommend that Staff witness Mr. Pung's proposal to allocate DTE's purchased capacity costs using the 75-0-25 Production Cost Allocator be rejected.

2. DTE's purchased capacity costs are largely related to renewable energy assets (wind, solar, and biomass) that were required for compliance with PA 295. These costs are largely fixed costs, and the majority of these costs are already allocated on the basis of energy.

3. DTE's proposal for $138 million of these costs to be allocated using 4 Coincident Peak ("4CP") demands should be approved.

4. Staff's proposal would inappropriately shift $4.5 million out of the Residential classes, with the Primary classes receiving $4.1 million.

5. DTE's renewable energy assets are largely fixed costs. They have no fuel cost and low Operation and Maintenance ("O&M"). DTE's Federal Energy Regulatory Commission ("FERC") Form 1 data shows that just 11% of its costs for renewable energy assets are variable and 89% of the costs are fixed.

6. Due to the process by which renewable assets are included in rates, DTE allocates about 60% of these costs on the basis of energy and 40% of the costs on the basis of demand.

7. The Michigan Public Service Commission ("Commission") should reject Staff witness Mr. Pung's proposal to allocator purchased capacity costs using the 75-0-25 allocator, and instead approve DTE's proposal to allocate these costs solely on the basis of 4CP demands.

II. Rebuttal to Staff Witness Pung

Q WHAT IS MR. PUNG'S PROPOSAL FOR THE ALLOCATION OF PURCHASED CAPACITY COSTS?

A Mr. Pung disagrees with the Company's position that purchased capacity costs should be allocated using allocator 251, which is based on the 4CP (coincident peak), 100% demand but excluding the R10 rate class. Instead, he proposes that purchased capacity costs be allocated using the 4CP 75-0-25 allocator.[1]

Q WHAT IS THE IMPACT OF MR. PUNG'S PROPOSAL TO ALLOCATE PURCHASED CAPACITY COSTS USING THE 4CP 75-0-25 ALLOCATOR?

A I have updated DTE's Class Cost of Service Study ("CCOSS") model to incorporate only this change. The results are shown in Table 1 below.

Table 1

Impact of Changing the Allocation of Purchased Capacity

Group	DTE Proposed Revenue Requirement ($000)	Revenue Requirement with Purchased Capacity Allocated with 75-0-25 Allocator ($000)	Change ($000)
Residential	$ 1,435,793	$ 1,431,252	$ (4,540)
Secondary	$ 814,280	$ 814,484	$ 205
Primary	$ 951,851	$ 955,996	$ 4,145
Lighting	$ 11,253	$ 11,444	$ 190
Total	**$ 3,213,177**	**$ 3,213,177**	**$ (0)**

[1]Direct Testimony of Mark J. Pung at page 11, line 3 through page 12, line 4.

As can be seen, this proposal would shift $4.5 million out of the Residential classes, with the Primary classes picking up $4.1 million, Secondary and Lighting each would receive approximately $0.2 million.

Q WHAT ARE DTE'S PURCHASED CAPACITY COSTS IN THIS PROCEEDING?

A In Table 2 below, I show DTE's $138.1 million of purchased capacity costs by group.

Table 2

DTE's Purchased Capacity Costs

PURPA/PA2 Contracts	$ 8,892
PA295/342 Renewable - Company Owned	$ 95,126
PA295/342 Renewable - PPA Wind	$ 30,503
PA295/342 Renewable - PPA LFG/Biomass	$ 4,840
Capacity Purchases	$ (1,308)
Total 2025 Purchased Capacity Costs	**$ 138,054**

Source: Exhibit A-26, Schedule P3

As shown above, the vast majority (95%) of these costs are related to renewable facilities required under PA 295. DTE's owned renewable assets comprise 69% of the total. The Public Utility Regulatory Policies Act ("PURPA") contracts and other renewable Purchased Power Agreements ("PPA") make up the rest, along with a small offset for DTE's capacity sales.

Q DO THE VALUES IN TABLE 2 REFLECT THE ENTIRE COST OF THE PA 295 ASSETS?

A No. Table 2 only shows what DTE has determined to be the capacity related portion of these assets, which is based on the fixed priced component of the transfer price at

the time the assets were approved. In total, the PA 295 assets have a cost of $388.3 million. DTE has separated these costs into "fuel related"[2] and "capacity-related" buckets in its Exhibit AB-26, Schedule P2. DTE's shows that $130.4 million is capacity-related and $257.9 million is "fuel-related."

Q UNDER DTE'S POSITION HOW ARE THE $388.3 MILLION OF PA 295 COSTS ALLOCATED?

A The $130.4 million deemed capacity-related is allocated using Allocator 251 which is 100% 4CP demands, excluding the R10 class. The $257.9 million of "fuel-related" PA 295 assets costs is allocated using allocator 192, which is 90% energy, 10% 4CP demands, excluding the R10 class. In my Exhibit AB-22, I have determined that 60% of these costs are allocated on the basis of energy and 40% are allocated on the basis of 4CP demands under DTE's proposal. Under Staff's proposal to allocate the capacity-related portion with the 4CP 75-0-25, the amount allocated on energy would increase to approximately 68%, and demand would decrease to 32%.[3]

Q ARE DTE'S COSTS FOR ITS OWNED RENEWABLE FACILITIES LARGELY FIXED?

A Yes. According to data compiled by S&P, from DTE's FERC Form 1 filings, DTE reports that roughly 89% of the costs of its renewable assets (wind, biomass, and solar) are fixed. With just 11% being variable. See Exhibit AB-23. This clearly makes sense. Wind and solar assets have no fuel costs. The majority of the costs of these assets

[2]With the exception of biomass plants, these assets would have no fuel costs as they are wind and solar resources. Fuel-related is the nomenclature used by DTE, and is simply the portion of the asset cost that has not been deemed to be capacity-related based on the fixed-cost proportion of the transfer prices.

[3]Demand-related portion would be $130.47 million x 75% + 257.862 million x 10% = $123.638 million or 32% of 388.332 million. Energy portion would then be 1-32% = 68%.

are incurred when they are installed, with little variable production expense. That is, regardless of customer energy consumption, or even energy generation of DTE's facilities, 89% of the costs would remain fixed.

Q DOES IT MAKE SENSE TO ALLOCATE THE CAPACITY-RELATED PORTION OF THE PA 295 RENEWABLE ASSETS USING THE 4CP 75-0-25 ALLOCATOR?

A No. As I have demonstrated, DTE's PA 295 renewable resources are largely fixed costs assets, and 60% of the costs of these assets are already allocated on the basis of energy. The 4CP 75-0-25 allocator might be appropriate for these costs if the entirety of them were allocated in the same manner, as with DTE's traditional production resources. That simply is not the case with the PA 295 renewable resource costs. If Staff's proposal were to be adopted, then 68% of the costs of the PA 295 renewable resource costs would be allocated on the basis of energy; despite as much as 89% of these costs being fixed costs. Since DTE's owned facilities represent the majority of the purchased capacity costs, the bulk of the purchased capacity costs would be unchanged, regardless of energy production or customer usage. Therefore, no additional energy allocation should be approved, and the currently approved methodology should remain in effect. The current methodology already over-allocates on the basis of energy because the majority of the purchased capacity costs are related to DTE's owned renewable generation facilities. If the Commission is to make any modification to the allocation of DTE's PA 295 renewable assets, it should allocate them more on the basis of demand than is currently approved and in the opposite direction of Staff's proposal.

Q HOW SHOULD DTE'S PURCHASED CAPACITY COSTS BE ALLOCATED?

A DTE'S purchased capacity costs should continue to be allocated using the 100% 4CP allocator, specifically, DTE's allocator 251.

Q DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A Yes, it does.

Qualifications of Brian C. Andrews

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Brian C. Andrews. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q PLEASE STATE YOUR OCCUPATION.

A I am a consultant in the field of public utility regulation and a Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EMPLOYMENT EXPERIENCE.

A I received a Bachelor of Science Degree in Electrical Engineering from the Washington University in St. Louis/University of Missouri - St. Louis Joint Engineering Program. I have also received a Master of Science Degree in Applied Economics from Georgia Southern University.

I have attended training seminars on multiple topics including class cost of service, depreciation, power risk analysis, production cost modeling, cost-estimation for transmission projects, transmission line routing, MISO load serving entity fundamentals and more.

I am a member and a former President of the Society of Depreciation Professionals. I have been awarded the designation of Certified Depreciation Professional ("CDP") by the Society of Depreciation Professionals. I am also a certified Engineer Intern in the State of Missouri.

As an Associate at BAI, and as a Senior Consultant, Consultant, Associate Consultant and Assistant Engineer before that, I have been involved with several

regulated and competitive electric service issues. These have included book depreciation, fuel and purchased power cost, transmission planning, transmission line routing, resource planning including renewable portfolio standards compliance, electric price forecasting, class cost of service, power procurement, and rate design. This has involved use of power flow, production cost, cost of service, and various other analyses and models to address these issues, utilizing, but not limited to, various programs such as Strategist, RealTime, PSS/E, MatLab, R Studio, ArcGIS, Excel, and the United States Department of Energy/Bonneville Power Administration's Corona and Field Effects ("CAFÉ") Program. In addition, I have received extensive training on the PLEXOS Integrated Energy Model and the EnCompass Power Planning Software. I have provided testimony on many of these issues before the Public Service Commissions in Arizona, Arkansas, California, Colorado, Florida, Illinois, Indiana, Kansas, Kentucky, Louisiana, Michigan, Minnesota, Missouri, Montana, New Mexico, Oklahoma, South Carolina, Texas, and Washington DC.

BAI was formed in April 1995. BAI provides consulting services in the economic, technical, accounting, and financial aspects of public utility rates and in the acquisition of utility and energy services through RFPs and negotiations, in both regulated and unregulated markets. Our clients include large industrial and institutional customers, some utilities and, on occasion, state regulatory agencies. We also prepare special studies and reports, forecasts, surveys and siting studies, and present seminars on utility-related issues.

In general, we are engaged in energy and regulatory consulting, economic analysis and contract negotiation. In addition to our main office in St. Louis, the firm also has branch offices in Corpus Christi, Texas; Louisville, Kentucky and Phoenix, Arizona.

Michigan Public Service Commission
DTE Electric Company
Projected 2025 PA295/PA342 Capacity-Related Generation Cost - Energy and Demand Allocations

Line No.	(a) Description	(b) Total Capacity-Related Generation Cost ($1,000)	(c) Total Fuel-Related Generation Cost[1] ($1,000)	(d) = (c) x 0.9 Allocated on Energy ($1,000)	(e) = (b) + (c) x 0.1 Allocated on 4CP Demand ($1,000)
1	**Renewable - Company Owned**				
2	Gratiot 2	$ 2,619	$ 26,606	$ 23,945	5,280
3	Minden	$ 1,189	$ 12,083	$ 10,875	2,398
4	Sigel	$ 2,670	$ 27,123	$ 24,411	5,382
5	McKinley	$ 545	$ 5,536	$ 4,982	1,099
6	Echo	$ 12,237	$ 19,891	$ 17,902	14,226
7	Brookfield	$ 7,893	$ 12,829	$ 11,546	9,175
8	Pinnebog	$ 6,235	$ 8,187	$ 7,368	7,054
9	Pine River	$ 15,934	$ 19,486	$ 17,537	17,883
10	Polaris	$ 20,124	$ 26,819	$ 24,137	22,806
11	Meridian	$ 19,594	$ 21,879	$ 19,691	21,782
12	DTE Solar Currents	$ 2,948	$ 1,570	$ 1,413	3,105
13	Romulus/Brownstown Solar	$ 42	$ 68	$ 61	49
14	Demille/Turrill/O'Shea Solar	$ 2,368	$ 3,110	$ 2,799	2,679
15	Ford	$ 34	$ 38	$ 34	38
16	Selfridge	$ 694	$ 543	$ 488	748
17					
18	**Total Renewable - Co-Owned**	**$ 95,126**	**$ 185,767**	**$ 167,190**	**$ 113,703**
19					
20	**Renewable - PPA Wind & Solar**				
21	DTE Renewable Generation, LLC - Stoney Corners / Garden	$ 806	$ 8,020	$ 7,218	1,608
22	Invenergy - Gratiot 1	$ 2,882	$ 21,976	$ 19,779	5,079
23	NextEra - Tuscola Bay	$ 3,866	$ 18,347	$ 16,513	5,701
24	NextEra - Tuscola Wind II	$ 9,386	$ 5,358	$ 4,822	9,922
25	NextEra - Pheasant Run	$ 7,980	$ 4,556	$ 4,100	8,436
26	Heritage - Big Turtle	$ 2,100	$ 1,450	$ 1,305	2,245
27	River Fork - Ranger Power	$ 3,483	$ 819	$ 737	3,565
28					
29	**Total PPA Wind & Solar**	**$ 30,503**	**$ 60,525**	**$ 54,473**	**$ 36,556**
30					
31					
32	**Renewable - PPA LFG/Biomass**				
33	L'Anse Warden	$ 3,370	$ 8,399	$ 7,559	4,210
34	Blue Water Renewables	$ 758	$ 1,811	$ 1,630	939
35	Waste Management	$ 712	$ 1,360	$ 1,224	848
36					
37	**Total PPA LFG/Biomass**	**$ 4,840**	**$ 11,570**	**$ 10,413**	**$ 5,997**
38					
39	**Total PA295/PA342 Capacity-Related Generation Cost**	**$ 130,470**			
40	**Total PA295/PA342 Fuel-Related Generation Cost**		**$ 257,862**		
41	**Total Costs Allocated on Energy**			**$ 232,076**	
42	**Total Costs Allocated on 4CP Demand**				**$ 156,256**
43	**Percents**			**60%**	**40%**

S&P Capital IQ PRO

DTE Energy Company | Plant Portfolio Summary (US Plant Financials ($000))

Company/ Subsidiary Name: All DTE Energy Co.
Report Year for Financials and Operations: 2023Y

Power Plant Category	*Plants Reporting*	*Reported Operating Capacity (MW)*	*Net Generation (MWh)*	*Fuel Expense ($000)*	*Non-Fuel Variable Production Expense ($000)*	*Variable Production Expense ($000)*	*Fixed Production Expense ($000)*	*Total Production Expense ($000)*
Total Coal	**2 of 2**	**4,119.7**	**16,239,761**	**422,347**	**23,044**	**445,391**	**79,781**	**525,172**
Coal: Steam Turbine	2 of 2	4,119.7	16,239,761	422,347	23,044	445,391	79,781	525,172
Uranium	**1 of 1**	**1,161.0**	**9,355,990**	**59,449**	**36,779**	**96,228**	**147,114**	**243,342**
Total Natural Gas	**13 of 14**	**4,227.0**	**12,026,176**	**265,174**	**18,369**	**283,543**	**22,966**	**306,509**
Natural Gas: Combined Cycle	3 of 3	1,241.5	8,527,036	176,462	6,555	183,018	10,498	193,516
Natural Gas: Gas Turbine	9 of 10	2,200.5	2,602,002	62,337	6,711	69,048	8,735	77,783
Natural Gas: Steam Turbine	1 of 1	785.0	897,138	26,374	5,102	31,476	3,733	35,209
Oil & Other Petroleum Products	**11 of 11**	**274.0**	**170**	**318**	**101**	**419**	**2,756**	**3,175**
Total Hydro	**1 of 1**	**1,103.6**	**1,111,825**	**35,413**	**1,952**	**37,365**	**2,279**	**39,644**
Hydro: Pumped Storage	1 of 1	1,103.6	1,111,825	35,413	1,952	37,365	2,279	39,644
Total Renewable	**18 of 38**	**1,467.3**	**3,120,361**	**2,923**	**1,738**	**4,660**	**36,015**	**40,675**
Wind	11 of 14	1,403.9	2,997,171	0	1,629	1,629	33,763	35,392
Biomass	1 of 16	10.0	56,425	2,923	108	3,031	52	3,083
Solar	6 of 8	53.4	66,765	0	0	0	2,200	2,200
Total	**46 of 67**	**12,352.5**	**41,854,283**	**785,624**	**81,982**	**867,606**	**290,911**	**1,158,516**

Current Capacity Summary is updated daily and includes all currently owned operating, out of service, under construction, and planned capacity. The aggregation is based off of unit level primary fuel and generation type categorizations and can be summarized by Ultimate Parent or Owner.

Plant Operations and Financials include all plants owned or ultimately owned by the listed company,in the selected report year, where data is available. Only power plants that report net generation, sourced from the EIA 906/923, FERC Form 1 or EPA, are included in the operations section. The financials section includes power plants with reported net generation and financials, sourced from the FERC Form 1, RUS 12, RUS 7, EIA 412 (pre-2004) and S&P Global Market Intelligence estimates. The aggregations are performed based on power plant primary fuel, generation type categorization and ownership percentage.

DTE Energy Company | Plant Portfolio Summary (US Plant Financials ($/MWh))

Company/ Subsidiary Name: All DTE Energy Co.
Report Year for Financials and Operations: 2023Y

Power Plant Category	*Plants Reporting*	*Reported Operating Capacity (MW)*	*Net Generation (MWh)*	*Fuel Expense ($/MWh)*	*Non-Fuel Variable Production Expense ($/MWh)*	*Variable Production Expense ($/MWh)*	*Fixed Production Expense ($/kW-year)*	*Total Production Expense ($/MWh)*
Total Coal	**2 of 2**	**4,119.7**	**16,239,761**	**26.01**	**1.42**	**27.43**	**19.37**	**32.34**
Coal: Steam Turbine	2 of 2	4,119.7	16,239,761	26.01	1.42	27.43	19.37	32.34
Uranium	**1 of 1**	**1,161.0**	**9,355,990**	**6.35**	**3.93**	**10.29**	**126.71**	**26.01**
Total Natural Gas	**13 of 14**	**4,227.0**	**12,026,176**	**22.05**	**1.53**	**23.58**	**5.43**	**25.49**
Natural Gas: Combined Cycle	3 of 3	1,241.5	8,527,036	20.69	0.77	21.46	8.46	22.69
Natural Gas: Gas Turbine	9 of 10	2,200.5	2,602,002	23.96	2.58	26.54	3.97	29.89
Natural Gas: Steam Turbine	1 of 1	785.0	897,138	29.40	5.69	35.09	4.76	39.25
Oil & Other Petroleum Products	**11 of 11**	**274.0**	**170**	**1,871.08**	**592.62**	**2,463.69**	**10.06**	**NM**
Total Hydro	**1 of 1**	**1,103.6**	**1,111,825**	**31.85**	**1.76**	**33.61**	**2.06**	**35.66**
Hydro: Pumped Storage	1 of 1	1,103.6	1,111,825	31.85	1.76	33.61	2.06	35.66
Total Renewable	**18 of 38**	**1,467.3**	**3,120,361**	**0.94**	**0.56**	**1.49**	**24.55**	**13.04**
Wind	11 of 14	1,403.9	2,997,171	0.00	0.54	0.54	24.05	11.81
Biomass	1 of 16	10.0	56,425	51.79	1.92	53.72	5.21	54.64
Solar	6 of 8	53.4	66,765	0.00	0.00	0.00	41.20	32.95
Total	**46 of 67**	**12,352.5**	**41,854,283**	**18.77**	**1.96**	**20.73**	**23.55**	**27.68**

Current Capacity Summary is updated daily and includes all currently owned operating, out of service, under construction, and planned capacity. The aggregation is based off of unit level primary fuel and generation type categorizations and can be summarized by Ultimate Parent or Owner.

Plant Operations and Financials include all plants owned or ultimately owned by the listed company,in the selected report year, where data is available. Only power plants that report net generation, sourced from the EIA 906/923, FERC Form 1 or EPA, are included in the operations section. The financials section includes power plants with reported net generation and financials, sourced from the FERC Form 1, RUS 12, RUS 7, EIA 412 (pre-2004) and S&P Global Market Intelligence estimates. The aggregations are performed based on power plant primary fuel, generation type categorization and ownership percentage.

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

Rebuttal Testimony of

Christopher C. Walters

On behalf of

Association of Businesses Advocating Tariff Equity

August 16, 2024

BRUBAKER & ASSOCIATES, INC.

Project 11638

STATE OF MICHIGAN
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Rebuttal Testimony of Christopher C. Walters

I. Introduction

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Christopher C. Walters. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q ARE YOU THE SAME CHRISTOPHER C. WALTERS WHO PREVIOUSLY FILED DIRECT TESTIMONY ON JULY 26, 2024 ON BEHALF OF ASSOCIATION OF BUSINESSES ADVOCATING TARIFF EQUITY ("ABATE")?

A Yes, I am.

Q WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A In my rebuttal testimony, I respond to the rate of return ("ROR") recommendation put forward by Michigan Public Service Commission Staff ("Staff") witness Mr. Joseph Ufolla. In particular, I respond to Mr. Ufolla's recommended ROE of 9.90%.

My silence on any particular issue raised in the direct testimony of Staff or other interveners should not be construed as tacit agreement.

II. Response to Mr. Ufolla

Q WHAT OVERALL ROR IS STAFF PROPOSING DTE BE ALLOWED IN THIS PROCEEDING?

A Through the testimony of its witness, Mr. Ufolla, Staff recommends DTE be allowed an overall ROR of 5.66%. Staff's recommended ROR is headlined by an allowed ROE of 9.90% and an investor-supplied capital structure that includes a 50.0% common equity ratio.[1]

Q DO YOU HAVE ANY CONCERNS WITH MR. UFOLLA'S ANALYSIS?

A Yes. My primary concern with Mr. Ufolla's recommended ROR lies with his recommendation that DTE's allowed ROE be set at 9.90%.

Q PLEASE SUMMARIZE THE ANALYTICAL METHODS MR. UFOLLA RELIES ON IN SUPPORT OF HIS RECOMMENDED ROE.

A Mr. Ufolla performed a DCF analysis and a traditional CAPM on a proxy group of eight natural gas utility holding companies, and three iterations of a Risk Premium model. He also observed the average authorized ROE for electric utilities in 2023 and 2024. Based on these data, Mr. Ufolla opines that DTE's cost of equity is within a range of 9.30% to 10.30%. His recommended ROE of 9.90% is above the midpoint of this range. The high-end of Mr. Ufolla's recommended range appears to be based on the results of his proxy group's average and median CAPM results of 10.23% and 10.31%, respectively. The low-end of his range appears to be supported by his Risk Premium

[1]Direct testimony of Joseph Ufolla at 4.

model results, which fall in the range of 8.63% to 9.66%. His DCF results fall between his CAPM and Risk Premium results.[2]

Q WHAT CONCERNS DO YOU HAVE WITH MR. UFOLLA'S ROE ANALYSIS?

A My main concerns with Mr. Ufolla's ROE analyses are as follows: (1) Mr. Ufolla's recommended ROE is unexplainably at the high-end of his recommended range of 9.30% to 10.30%; (2) Mr. Ufolla's ROE recommendation is inconsistent with his recommendation in DTE's pending gas rate case (U-21291), and; (3) Mr. Ufolla's CAPM analysis is overstated because it is based on five-year betas that are not representative of current market conditions, perceived risk of regulated utilities, or investor expectations.[3] Absent these flaws, the high-end of Mr. Ufolla's range would be significantly lower than 10.3%.

Q WHY DO YOU BELIEVE MR. UFOLLA'S RECOMMENDATIONS IN THIS CASE ARE INCONSISTENT WITH HIS RECOMMENDATIONS IN DTE'S PENDING GAS RATE CASE, U-21291?

A In that case, Mr. Ufolla has the same recommended range of 9.3% to 10.3%.[4] Yet, in that case, Mr. Ufolla recommended DTE Gas be awarded an ROE of 9.8%, which is the midpoint of his recommended range. Unexplainably, Mr. Ufolla recommends DTE Electric be authorized an ROE of 9.9% in this case despite having the same recommended range and despite DTE Gas and DTE Electric both currently having the same ROE of 9.9% currently authorized.[5] There is no reason for DTE Electric's ROE

[2] *Id.* at 21.
[3] Staff Exhibit S-4, Schedule D-5, page 4.
[4] MPSC Case No. U-21291, Direct Testimony of Joseph Ufolla at 24.
[5] Direct testimony of Joseph Ufolla at 21.

be set in the upper-half of Mr. Ufolla's range. As I explain throughout this testimony, Mr. Ufolla's recommended range is overstated.

Q WHY DO YOU BELIEVE MR. UFOLLA'S RECOMMENDED RANGE IS OVERSTATED?

A The high-end of Mr. Ufolla's range (10.30%) is based on the results of his CAPM analysis which range from 10.23% to 10.31%.[6] As I explained in my direct testimony, current Value Line beta estimates, which are used in Mr. Ufolla's CAPM, are based on five years of historical prices and volatility. This means that Value Line's betas are being heavily impacted by the market fallout as a result of the onset of a global pandemic in early 2020. As such, betas based on five years of data are not representative of investor expectations, current market conditions, or perceived market risk of regulated utility companies. As shown on Mr. Ufolla's Exhibit S-4, Schedule D-5, his average proxy group beta is 0.94, and ranges from 0.80 to 1.15. It is simply unrealistic to assume that utilities are approximately as risky as the market, on average. As I demonstrated in my direct testimony, when measuring betas after removing the impact of the global pandemic, utility betas are approximately 0.72 under Value Line's adjustment methodology.[7] This level of beta is in-line with their long-term averages.

Q WHAT WOULD MR. UFOLLA'S CAPM RESULTS LOOK LIKE USING A BETA OF 0.72 INSTEAD OF THE BIASED ESTIMATE OF 0.94 HE RELIED ON?

A Assuming Mr. Ufolla's risk-free rate of 3.85% and market risk premium of 6.80%, his CAPM results would be lowered from 10.23% to 8.75%. Giving each of those results

[6] *Id*.
[7] Direct testimony of Christopher Walters at 54-57.

equal weight, the midpoint of 10.23% and 8.75% is 9.37%, or nearly 100 basis points lower than Mr. Ufolla's recommended high-end of 10.30%.

Q DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

*** * * * ***

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

PROOF OF SERVICE

STATE OF MICHIGAN)
) ss
COUNTY OF WAYNE)

Stephen A. Campbell, being first duly sworn, deposes and says that on August 16, 2024, he did cause to be served the ***Association of Businesses Advocating Tariff Equity's Rebuttal Testimony & Exhibits of James R. Dauphinais, Brian C. Andrews, and Christopher C. Walters***, as well as this ***Proof of Service***, in the above docket, via electronic mail, to the persons identified on the attached service list.

Stephen Campbell

Digitally signed by: Stephen Campbell
DN: CN = Stephen Campbell email = scampbell@clarkhill.com C = US O = Clark Hill PLC
Date: 2024.08.16 13:58:58 -04'00'

Stephen A. Campbell

SERVICE LIST
MPSC Case No. U-21534

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