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**

Direct Testimony and Exhibit of

James R. Dauphinais

On behalf of

Association of Businesses Advocating Tariff Equity

July 26, 2024

BRUBAKER & ASSOCIATES, INC.

Project 11638

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Direct Testimony of James R. Dauphinais

I. Introduction

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A James R. Dauphinais. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q WHAT IS YOUR OCCUPATION?

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

Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A This information is included in Appendix A to my testimony.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am appearing on behalf of the Association of Businesses Advocating Tariff Equity ("ABATE"). ABATE consists of large usage customers that purchase substantial

amounts of electric power and/or delivery service from DTE Electric Company ("DTE" or "Company"). They primarily take service under DTE Rate D8, Rate D11, Rider 3 and/or Rider 10.

Q HAVE YOU PRESENTED TESTIMONY IN PRIOR ELECTRIC REGULATORY PROCEEDINGS BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION ("COMMISSION")?

A Yes. Over my 27 years of employment by BAI, I have provided testimony to the Commission on several occasions regarding issues that include revenue requirement, electric rate design, class cost of service, power supply cost recovery, resource planning, standby service rates, transmission planning and transmission line routing. In recent years this has included providing testimony in: (i) the most recent general electric rate cases of Consumers Energy Company (Case No. U-20963, U-21224 and U-21389), DTE (Case Nos. U-18014, U-18255, U-20162, U-20561, U-20836 and U-21297) and Indiana Michigan Power Company (Case Nos. U-18370, U-20359 and U-21461); (ii) the original Section 6w State Reliability Mechanism ("SRM") Capacity Charge proceedings of Consumers Energy Company (Case No. U-18239) and DTE (Case No. U-18248); and (iii) the most recent Integrated Resource Plan cases proceedings of Consumers Energy Company (Case No. U-21090), DTE (Case No. U-21193), and Indiana Michigan Power Company (Case No. U-21189).

Q WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A My testimony will address: (i) DTE's use of a projected test year, (ii) DTE's proposed Investment Recovery Mechanism ("IRM") proposals in this proceeding, and (iii) the MISO Locational Marginal Price ("LMP") used DTE's Rider 10.

My silence with regard to any position taken by DTE in its application or direct testimony in this proceeding does not indicate my endorsement of that position.

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

A My conclusions and recommendations are as follows:

1. DTE is requesting to increase its electric rates by $456.4 million despite it reporting a revenue sufficiency of $80.5 million during its historical test year in this proceeding, a revenue sufficiency of $93.6 million during the historical test year of its most recent previous rate filing (Case No. U-21297) and a revenue sufficiency of $111.7 million during the historical test year of its next most recent previous rate filing (Case No. U-20836).

2. DTE's proposed large expansion of the projected capital expenditures included in its approved Year 2 (2025) distribution IRM should be rejected and its request to add two additional years, rather than one additional year, to its distribution IRM should be rejected as well.

3. To the extent the Commission in this proceeding authorizes a Year 3 for DTE's distribution IRM, the included investments should be limited to the existing "Conversions," "Subtransmission Redesign and Rebuild," "Breaker Replacement" and "URD Replacement" categories in a total amount not to exceed $275.0 million.

4. As discussed in my testimony herein DTE's recent rate increases have been driven by the use of projected rather than historical test years for ratemaking and aggressive capital expenditures[1] coupled with the filing of frequent rate cases.

5. As detailed in my testimony herein, based on DTE's track record with respect to the use of a projected test year, the Commission should reject DTE's proposed use of one in this proceeding and require DTE to use its proposed historical test year as the basis of its revenue requirement in this proceeding. Given that DTE is reporting a revenue sufficiency of $80.5 million for its historical test year in this proceeding, this would eliminate DTE's proposed rate increase in its entirety.

[1]With respect to capital expenditures, since at least Case No. U-18014, DTE in electric rate case applications has generally cited new investments in infrastructure as one of the largest, if not the largest, contributor to its requested rate relief. For example, in Case No. U-18014, DTE attributed $173 million of its requested rate relief of $344 million to investment-related costs (Case No. U-18014 Application at Paragraph 4 and Attachment 1 at Rate Base and Working Capital). Similarly, in Case No. U-20561, DTE attributed $219 million of its requested rate relief of $351 million to investment-related costs (Case No. U-20561 Rate Case Summary). In addition, in Case No. U-20836, Case No. U-21297 and the current proceeding (Case No. U-21534), DTE has indicated that the rate increase requests in those proceedings were, or are, being primarily driven by the Company's continued distribution infrastructure and generation investments (Case No. U-20836, January 18, 2022 Rate Case Summary at 1-2; Case No. U-21297, February 7, 2023 Rate Case Summary at 2; and Case No. U-21534, March 25, 2024 Rate Case at 2).

6. As detailed in my testimony herein, if despite my recommendation, the Commission allows DTE to use a projected test year in this proceeding, the Commission should be vigilant to ensure the following: (i) that the projected expenses and investments included in DTE's projected test year are truly necessary to provide reliable electric service at lowest reasonable cost; (ii) that DTE is essentially irrevocably committed to incur them or otherwise cannot avoid them; and (iii) they are precisely quantified by DTE with respect to their amount and timing.

7. DTE's Rider 10 should be such that each Rider 10 customer has the ability to annually elect to use the MISO day-ahead energy LMP or the MISO real-time energy LMP.

II. Projected Test Year

Q YOU HAVE ALLEGED THAT, ALONG WITH THE PURSUIT OF AGGRESSIVE CAPITAL EXPENDITURES, DTE'S USE OF A PROJECTED TEST YEAR IS A MAJOR DRIVER OF DTE'S PROPOSED RATE INCREASE IN THIS PROCEEDING. PLEASE EXPLAIN WHY THIS IS THE CASE.

A The best starting point for exploring this issue is to compare DTE's own historical and projected test year calculations for this case and its six most recent general rate cases. I present this comparison below in Table JRD-1.

TABLE JRD-1

Historical Test Year and Projected Test Year

Rate Sufficiency / (Deficiency)

Case	Year Filed	Historical Test Year Sufficiency / (Deficiency)	Projected Test Year Sufficiency / (Deficiency)	Difference Between Historical and Projected
U-18014	2016	$33,404,000	($343,972,000)	($377,376,000)
U-18255	2017	($50,009,000)	($230,942,000)	($180,933,000)
U-20162	2018	($18,335,000)	($328,440,000)	($310,105,000)
U-20561	2019	($111,501,000)	($350,688,000)	($239,187,000)
U-20836	2022	$111,696,000	($388,222,000)	($499,918,000)
U-21297	2023	$93,577,000	($618,536,000)	($712,113,000)
U-21534	2024	$80,492,000	($456,434,000)	($536,926,000)
Total		$139,324,000	($2,717,234,000)	($2,856,558,000)

Sources:
Case No. U-18014, Exhibit A-1 and Exhibit A-8, Schedule A1
Case No. U-18255, Exhibit A-1 and Exhibit A-8, Schedule A1
Case No. U-20162, Exhibit A-1 and Exhibit A-11, Schedule A1
Case No. U-20561, Exhibit A-1 and Exhibit A-11, Schedule A1
Case No. U-20836, Exhibit A-1 and Exhibit A-11, Schedule A1
Case No. U-21297, Exhibit A-1 and Exhibit A-11, Schedule A1
Case No. U-21534, Exhibit A-1 and Exhibit A-11, Schedule A1

What this shows is that even under DTE's own numbers DTE would not have been able to seek the large rate increases it has sought in its last six general rate cases, and is seeking in this proceeding, but for being permitted to use a projected test year. To put it another way, the use of a projected test year allows DTE to begin recovery of

costs before those costs have been verified as being real and prudently incurred. This has had and continues to have several adverse impacts on customers.

First, it has caused and continues to cause customers to experience rate increases sooner because rates are being based on future projections.

Second, it has resulted in higher rates for customers than if rates were based on the historical test year.

Third, it has allowed and continues to allow DTE to fill its projections with proposed capital expenditures and expenses that either DTE has not irrevocably committed to making or otherwise can avoid if it finds it advantageous to do so to improve its realized rate of return for its shareholders. This can allow DTE to collect revenue from its customers for capital expenditures or expenses it does not ultimately incur or has not yet incurred when rates are placed into effect. This unreasonably benefits DTE's shareholders at the expense of DTE's customers.

Finally, the use of a projected test year greatly handicaps the Commission Staff and intervenors in reviewing DTE's rate filings to ensure the projected capital expenditures and expenses are reasonable because they are not actual capital expenditures and expenses reflected on DTE's books, but rather projections developed over many separate cost subaccounts and revenue categories. This requires much more time and greater resources than are necessary in a rate proceeding that utilizes a historical test year all while the rate case timing has been compressed down to a 10-month time frame. As a result, while some inappropriate cost projections by DTE may be identified and successfully disallowed as a result of Commission Staff and intervenor review of DTE's projections, many other inappropriate cost projections may be missed and inappropriately included in DTE's rates at the expense of its customers as I have outlined above.

Q ARE DTE'S PROJECTED BRIDGE PERIOD CAPITAL EXPENDITURES AND FORECASTED TEST YEAR EXPENSES AND CAPITAL EXPENDITURES KNOWN AND MEASURABLE CHANGES TO ITS HISTORICAL TEST YEAR?

A No, they are not. Known and measurable changes are changes to costs that are inescapable and precisely identifiable in amount and timing. Future capital expenditures and projected expenses are often not inescapable, not precisely identifiable in amount and timing, or both. When they are escapable or not precisely identifiable with respect to amount and timing, they are not known and measurable changes from the historical test year. Furthermore, many of the capital expenditures and expenses that DTE has attempted to recover in past general rate cases and is attempting to recover in this current proceeding, as shown by the direct testimony of my colleague, Ms. York, are highly speculative. These include capital expenditures and expenses that DTE has not irrevocably committed to make. These too are not known and measurable changes from the historical test year.

Q PLEASE PROVIDE SOME EXAMPLES OF CHANGES FROM A HISTORICAL TEST YEAR THAT ARE KNOWN AND MEASURABLE CHANGES.

A Examples of valid known and measurable changes to historical test year amounts include:

- Normalization to address the effects of volatility, such as those related to economic conditions or weather, and unusual events such as extended forced generation outages that distort the amounts that fall within the historical test year;

- Annualization to address costs, such as those associated with nuclear generation refueling outages and other types of extended planned generation outages, that regularly occur on a periodic basis, but not in every year;

- Costs that only occurred during the later months of the historical test year and are expected to continue at that same level on a going forward basis; and

- Imminent changes in costs that will occur during the period between the end of the historical test period and the date new base rates go into effect and are expected to continue on a going forward basis.

Q IS THERE ANY EVIDENCE THAT SUGGESTS THAT DTE HAS BEEN OVER COMPENSATED AS A RESULT OF BEING ALLOWED TO USE A PROJECTED TEST YEAR?

A Yes. As my Table JRD-1 shows, in its rate filing in this proceeding and in its two rate filings before it, DTE has consistently reported large revenue sufficiencies for its historical test year that have ranged from $80.5 to $111.7 million. This means that, in each of these historical test years (calendar years 2020, 2021 and 2022), DTE received revenues $80.6 to $111.7 million higher than necessary to earn its authorized rate of return during that historical test year. While COVID-19 may have in part caused the large revenue sufficiencies reported for 2020 and 2021, it does not change the fact that DTE's present rates were ultimately more generous than they needed to be to provide DTE a reasonable opportunity to earn its authorized return.

It is also important to note that the historical test year values presented in my Table JRD-1 are DTE's reported historical test year values. If these historical test year values were closely examined they might very well reveal costs that are not recoverable in rates. As a result, DTE's actual revenues in excess of its authorized rate of return in each of these three historical test years (2020, 2021 and 2022) may very well have been well in excess of the approximately $80.6 to $111.7 million DTE has reported.

The bottom line with respect to these most recent three historical test year results is that, if projected costs for DTE were being properly set in DTE's rate proceedings, about half the time these historical test years would show a revenue sufficiency and about half the time these historical test years would show a revenue

deficiency. However, this is not what is happening. Instead, DTE is consistently being granted rates based on projected costs that are clearly much higher than DTE is subsequently actually incurring such that DTE is consistently earning a windfall of tens of millions of dollars per year. This will not end until the Commission: (i) disallows DTE from using a projected test year for its base rates, (ii) becomes much more aggressive in terms of rejecting DTE's unsupported projections, or (iii) institutes other measures that prevent or greatly limit DTE overearnings that result from DTE's over projections.

Q IS THE COMMISSION REQUIRED TO SET RATES USING A PROJECTED TEST YEAR?

A No. As the Commission discussed in its November 2, 2009 Order in Case No. U-15645, p. 8, Section 6a(1) of Act 286, MCL 460.6a(1), provides that a utility "may use projected costs and revenues for a future consecutive 12-month period" to develop its requested rates and charges. The Commission added that the Staff and intervenors should direct their focus "upon the strengths and weaknesses of the evidentiary presentations of the parties regarding specific expense and revenue projections." In a case where a utility decides to base its filing on a fully projected test year, however, the utility bears the burden to substantiate its projections.[2] Recognizing the statutory time constraints present in a base rate case, the Commission has directed utilities to include all evidence (or sources of evidence) in support of their test year projections in their initial rate case filings.[3] If the utility cannot or will not provide sufficient support for a particular revenue or expense item (particularly for an item that substantially deviates from the historical data), "the Commission may choose an alternative method for

[2] *In re Detroit Edison Application for Rate Increase*, MPSC Case No. U-15768, January 11, 2010 Order, p 9.
[3] *Id*.

determining the projection."[4] That alternative method should be the use of the historical test year amount for that item adjusted for only known and measurable changes to the amount for that item.

Q WHAT DO YOU RECOMMEND TO THE COMMISSION WITH RESPECT TO THIS ISSUE?

A Given DTE's track record with respect to its use of a projected test year causing it to be greatly overcompensated by its customers, my primary recommendation is that the Commission send a strong signal to DTE that DTE's consistent overearning must stop. I propose the Commission do this by outright rejecting DTE's proposed use of a projected test year in this proceeding rather than trying to flushout all of DTE's poorly supported cost projections – an approach that is clearly not sufficiently working given DTE's record of three years of large historical test year revenue sufficiencies. This would appropriately reject DTE's request for a rate increase in this proceeding in its entirety given DTE is showing a $80.5 million revenue sufficiency in its proposed historic test year in this proceeding.

Q IF, DESPITE YOUR RECOMMENDATION, THE COMMISSION ALLOWS DTE TO USE A PROJECTED TEST YEAR IN THIS PROCEEDING, WHAT DO YOU INSTEAD RECOMMEND TO THE COMMISSION?

A If, despite my recommendation, the Commission decides to allow DTE to use a projected test year for this proceeding, which it should not, I have a near-term recommendation and a one long-term recommendation, discussed further below, that the Commission should instead adopt.

[4] *Id.*

First, I recommend the Commission, be much more vigilant and aggressive with respect to ensuring the expenses and investments being projected by DTE for its projected test year are truly expenses and investments that are necessary to provide reliable electric service at lowest reasonable cost. The Commission should also ensure that DTE is irrevocably committed to incur its projected expenses and investments or otherwise cannot avoid them. Finally, the Commission should ensure that DTE's projected investments and expenses are precisely quantified by DTE with respect to both amount and the specific quarter in which DTE will incur these investments and expenses. As I have noted, it is clear from the recent track record of DTE reporting historical test year revenues $80.5 to $111.7 million in excess of its authorized return in its three most recent general rate proceedings (the current one and Case Nos. U-20836 and U-21297)[5] that it is likely to some extent either questionable projections of DTE are not being caught by intervenors and/or Staff in their review of DTE's proposals given the complexity of verifying those projections, the Commission has provided too great of a benefit of doubt to DTE with respect to the costs found to be questionable by intervenors and/or Staff, DTE is not actually incurring the costs it has projected, or some combination of the three has been occurring. DTE will essentially continue to earn a rate of return higher than authorized by the Commission unless and until this issue is brought under control. However, given DTE's consistent very large revenue sufficiencies for its three most recent historical test year, ABATE has no confidence, without major reform with respect to the use of projected test years, which the Commission will be generically exploring as part of Case No. U-21637, that the Commission will be able to sufficiently root out DTE's over-projections of cost in this current proceeding. For this reason, until the Commission can in Case No. U-21637

[5]Table JRD-2.

explore other alternatives to reign in DTE's overearning related to its use of a project test year and implement the reforms resulting from that exploration, my primary recommendation is to outright reject DTE's proposed use of a projected test year.

Q WHAT IS YOUR LONGER TERM RECOMMENDATION TO THE COMMISSION?

A ABATE recommended in its May 14, 2021 and August 11, 2021 filed comments in Case No. U-18238 that, as part of reconvening a collaborative work group to discuss the experience and impact of the rate case filing requirements set forth in its July 31, 2017 order in Case No. U-18238, the Commission have the collaborative workgroup address the use of projected test years and utility ROE requests continuing to result in excess revenue collection from customers under the Commission's current minimum filing requirements.[6] As detailed in its May 14, 2021 Comments, the Commission should examine: (i) customer benefits and detriments that have resulted from the use of projected test years; (ii) conditions under which the Commission would reject the use of a projected test year; (iii) categories of expenses/revenues that are uniquely difficult to predict so as to render their inclusion in a projected test year inappropriate; (iv) minimum criteria to reasonably demonstrate a sufficient commitment by the utility to actually incur the expenses it projects; (v) length of time between the end of the historical test year and the beginning of the proposed projected test year; (vi) a method of tracking projections for various costs to determine consistency and extent of over- or under-projection and potential projection guardrails or limits; and (vii) whether the use of a projected test year by a utility should factor into its authorized ROE. Further attention to these issues could help tailor and bolster the Filing Requirements and utility

[6]U-18238, ABATE May 14, 2021 Comments at 1.

rate case applications to ensure that projected test year filings more accurately and reasonably align projections with utility revenue requirements.[7]

While the Commission's August 11, 2022 order in Case No. U-18238 did not adopt ABATE's recommendation, the Commission has recently opened a new proceeding in Case No. U-21637 to investigate opportunities for improving the process by which it reviews applications filed under ML 460.6a. In its May 23, 2024 Order in that proceeding, the Commission has posted a number of questions to interested persons for comment, including questions with respect to the continued use of projected test years by the utilities the Commission regulates.

ABATE will be actively participating in this new proceeding and recommends that the Commission fully utilize this new proceeding to examine: (i) customer benefits and detriments that have resulted from the use of projected test years; (ii) conditions under which the Commission would reject the use of a projected test year; (iii) categories of expenses/revenues that are uniquely difficult to predict so as to render their inclusion in a projected test year inappropriate; (iv) minimum criteria to reasonably demonstrate a sufficient commitment by the utility to actually incur the expenses it projects; (v) length of time between the end of the historical test year and the beginning of the proposed projected test year; (vi) a method of tracking projections for various costs to determine consistency and the extent of over- or under-projection and potential projection guardrails or limits; and (vii) whether the use of a projected test year by a utility should factor into its authorized ROE. The fact of the matter is that utility use of projected test years for ratemaking remains broken and will continue to be so until the Commission fully addresses the issues associated with the use of projected test years by the utilities under its jurisdiction.

[7] *Id.* at 5-6.

III. DTE'S Distribution Investment Recovery Mechanism

Q DOES THE COMPANY CURRENTLY HAVE AN IRM?

A Yes. In the Company's last general rate case proceeding, Case No. U-21297, the Commission for the first time authorized an IRM for the Company for certain categories of distribution investments in the amount of approximately $61.9 million for Year 1 (December 1, 2023 through December 31, 2024) and $290.1 million for Year 2 (January 1, 2025 through December 31, 2025).[8] It is important to note the accompanying DTE distribution IRM surcharge only began to apply to customer bills a little over seven months prior to the filing of my direct testimony herein and the Company's first distribution IRM reconciliation proceeding will not commence until sometime in 2025. In addition, it is important to note the Commission in Case No. U-21297 denied the Company's request for a Year 3 (January 1, 2026 through December 31, 2026) for its distribution IRM with an investment of $532.7 million.

Specifically:

> "[T]he Commission finds that approval is limited to Plan Years 1 and 2. As noted on the record, there is ongoing discussion regarding PBR in Case No. U-21400 and an ongoing audit in Case No. U-21305. Therefore, the Commission finds that limiting the approval to the first two years will allow the company to move forward with the IRM without precluding the incorporation of any potential insights gained from those proceedings to better inform the potential continuation of the IRM."[9]

Q WHAT IS THE COMPANY PROPOSING IN THE CURRENT PROCEEDING WITH RESPECT TO ITS DISTRIBUTION IRM?

A The Company proposes to add a Year 3 (calendar year 2026) with $530.0 million of investment and a Year 4 (calendar year 2027) with $720.0 million of investment. In

[8]Case No. U-21297 Final Order at 291.
[9]Case No. U-21297 Final Order at 289.

doing so, the Company proposes to add a new category of investments called "Pole and Pole Top Maintenance and Modernization," which contributes $150 million of the proposed investment in 2026 and $200 million of the proposed investment in 2027.[10] In addition, the Company proposes to broaden the investment category "4.8 kV Circuit Automation" to "Distribution Automation," which increases annual investment in 2026 and 2027 to $105.0 million and $180.0 million, respectively, versus the $24.4 to $26.4 million authorized for Year 1 and Year 2 of its distribution IRM.[11] Finally, while not outright requesting it, the Company indicates it would support expanding its authorized $290.1 million of capital expenditures for Year 2 (calendar year 2025) for its distribution IRM by $434.1 million to $724.1 million by adding four additional areas of capital investment beyond that authorized by the Commission in Case No. U-21297.[12]

Q HOW DO YOU RESPOND TO DTE'S NEW DISTRIBUTION IRM PROPOSALS?

A DTE's proposals to: (i) add up to $434.1 million of investment to Year 2 of its authorized distribution IRM, (ii) add the new category of investment called "Pole and Pole Tape Maintenance and Modernization," (iii) expand the scope of "4.8 kV Circuit Automation" to "Distribution Automation" and (iv) the add a Year 4 to its authorized distribution IRM should all be rejected. The Commission at this time should only permit DTE to add a Year 3 to its distribution IRM and only for the existing authorized categories of "Conversion," "Subtransmission Redesign and Rebuild," "Breaker Replacement" and "URD Replacement" for a total investment amount for Year 3 of $275.0 million.

I make this recommendation for the following reasons:

- DTE's distribution IRM should not at this time be dramatically expanded and extended as proposed by DTE given DTE's distribution IRM is still in its infancy. Year 1 just barely commenced seven months prior to the filing of this testimony and

[10]DTE witness Foley Direct at NTF-8 to NTF-9.
[11]DTE witness Foley Direct at NTF-8 to NTF-9.
[12]DTE witness Foley Direct at NTF-18.

the first DTE distribution IRM reconciliation will not commence until sometime in 2025; and

- The term of the authorized distribution IRM for DTE should at this time be limited to no longer than truly necessary, as the Commission concluded in its Final Order in Case No. U-21297, until potential insights from Case Nos. U-21400 and U-21305 are gained to better inform continuation of the distribution IRM.

This said, to address DTE's concern with respect to a temporary stopping and starting of its distribution IRM[13] and to potentially reduce the likelihood DTE would file a rate case in 2025 for the sole purpose of adding a Year 3 to its distribution IRM, I do not oppose the Commission at this time adding a Year 3 to DTE's distribution IRM for the existing investment categories of "Conversions," "Subtransmission Redesign and Rebuild," "Breaker Replacement" and "URD Replacement" in the amounts proposed by DTE in this proceeding for Year 3, which total to $275.0 million. This would at this time only authorize one additional year for the distribution IRM and only do so for a level of investment similar to that already authorized for Year 2 ($290.1 million).

Q DTE ARGUES A YEAR 4 NEEDS TO BE AUTHORIZED AT THIS TIME TO AVOID A LAPSE IN THE IRM AND PROVIDE GREATER CERTAINTY WITH RESPECT TO ITS FUTURE USE.[14] HOW DO YOU RESPOND?

A The risk of a temporary lapse in the distribution IRM is sufficiently addressed by adding a Year 3 in the limited manner I have recommended. With respect to longer term future use of the IRM, granting a Year 4 would essentially presume a long-term future that has not yet been determined by the Commission. As I have recommended, the request for the authorization of a Year 4 for DTE's distribution IRM should at this time be rejected.

[13]DTE witness Foley Direct Testimony at 16.
[14]DTE witness Foley Direct at NTF-16.

IV. DTE Rider 10: MISO Locational Marginal Price ("LMP")

Q CAN YOU PLEASE BRIEFLY DESCRIBE DTE RIDER 10?

A DTE Rider 10 ("R10") is a large customer interruptible service rate under which the load is designated as a planning resource under the MISO Resource Adequacy Construct and a significant portion of the customer's power supply rates involve a pass-through of the MISO real-time hourly Locational Marginal Price ("LMP") for energy.[15]

Q WHAT IS YOUR CONCERN WITH RESPECT TO R10 IN THIS CURRENT PROCEEDING?

A ABATE members utilizing R10 would like to have the option, on an annual basis, of selecting the use of the applicable day-ahead LMP rather than the applicable real-time LMP. The reason for this is twofold. First, provided a customer provides a day-ahead estimate of hourly demand to DTE and DTE submits it into the MISO day-ahead market, the vast majority of the energy for the customer will be obtained by DTE from MISO at the hourly day-ahead LMP rather than the hourly real-time LMP. Second, the day-ahead LMP is known before real-time such that a customer using it would in advance have a price signal with respect to the impact on its bill of increasing or decreasing its energy consumption in real-time.

Q IS THE REAL-TIME LMP REASONABLY PREDICTABLE IN ADVANCE?

A On average, it is based on day-ahead LMP values, but it is not so on an hour-to-hour basis. As a result, selection of the day-ahead LMP by a R10 customer would provide it a much more predictable price signal.

[15]DTE Electric Company, Electric Tariff at D-91.00.

Q WHY WOULD IT BE AN ANNUAL ELECTION?

A It would be an annual election to ensure no customer tries to game moving back and forth between day-ahead and real-time LMPs on an hour-to-hour or day-to-day basis. Instead, customers must live with their selection for an entire year at a time.

Q ARE YOU AWARE OF OTHER UTILITY TARIFF RATES SIMILAR TO DTE R10 THAT USE THE DAY-AHEAD RATHER THAN REAL-TIME LMP?

A Yes. Northern Indiana Public Service Company ("NIPSCO") Rate 531 under Tier 2 service, which has a number of similarities to DTE R10, uses the day-ahead LMP rather than the real-time LMP. I have attached a copy of NIPSCO Rate 531 as Exhibit AB-3 to this testimony. Rate 531 Tier 2 service is described on pages 2 and 3 of the exhibit.

Q WHAT DO YOU RECOMMEND?

A I recommend the Commission require DTE to modify its R10 tariff to allow all R10 customers on an annual basis to choose between the applicable day-ahead LMP or the applicable real-time LMP.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

Qualifications of James R. Dauphinais

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, USA.

Q PLEASE STATE YOUR OCCUPATION.

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

Q PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I graduated from Hartford State Technical College in 1983 with an Associate's Degree in Electrical Engineering Technology. Subsequent to graduation, I was employed by the Transmission Planning Department of the Northeast Utilities Service Company[1] as an Engineering Technician.

While employed as an Engineering Technician, I completed undergraduate studies at the University of Hartford. I graduated in 1990 with a Bachelor's Degree in Electrical Engineering. Subsequent to graduation, I was promoted to the position of Associate Engineer. Between 1993 and 1994, I completed graduate level courses in the study of power system analysis, power system transients and power system protection through the Engineering Outreach Program of the University of Idaho. By 1996 I had been promoted to the position of Senior Engineer.

[1] In 2015, Northeast Utilities changed its name to Eversource Energy.

In the employment of the Northeast Utilities Service Company, I was responsible for conducting thermal, voltage and stability analyses of the Northeast Utilities' transmission system to support planning and operating decisions. This involved the use of load flow, power system stability and production cost computer simulations. It also involved examination of potential solutions to operational and planning problems including, but not limited to, transmission line solutions and the routes that might be utilized by such transmission line solutions. Among the most notable achievements I had in this area include the solution of a transient stability problem near Millstone Nuclear Power Station, and the solution of a small signal (or dynamic) stability problem near Seabrook Nuclear Power Station. In 1993 I was awarded the Chairman's Award, Northeast Utilities' highest employee award, for my work involving stability analysis in the vicinity of Millstone Nuclear Power Station.

From 1990 to 1996, I represented Northeast Utilities on the New England Power Pool Stability Task Force. I also represented Northeast Utilities on several other technical working groups within the New England Power Pool ("NEPOOL") and the Northeast Power Coordinating Council ("NPCC"), including the 1992-1996 New York-New England Transmission Working Group, the Southeastern Massachusetts/Rhode Island Transmission Working Group, the NPCC CPSS-2 Working Group on Extreme Disturbances and the NPCC SS-38 Working Group on Interarea Dynamic Analysis. This latter working group also included participation from a number of ECAR, PJM and VACAR utilities.

From 1990 to 1995, I also acted as an internal consultant to the Nuclear Electrical Engineering Department of Northeast Utilities. This included interactions with the electrical engineering personnel of the Connecticut Yankee, Millstone and

Seabrook nuclear generation stations and inspectors from the Nuclear Regulatory Commission (“NRC”).

In addition to my technical responsibilities, from 1995 to 1997, I was also responsible for oversight of the day-to-day administration of Northeast Utilities' Open Access Transmission Tariff. This included the creation of Northeast Utilities' pre-FERC Order No. 889 transmission electronic bulletin board and the coordination of Northeast Utilities' transmission tariff filings prior to and after the issuance of Federal Energy Regulatory Commission (“FERC” or “Commission”) FERC Order No. 888. I was also responsible for spearheading the implementation of Northeast Utilities' Open Access Same-Time Information System and Northeast Utilities’ Standard of Conduct under FERC Order No. 889. During this time, I represented Northeast Utilities on the Federal Energy Regulatory Commission's "What" Working Group on Real-Time Information Networks. Later I served as Vice Chairman of the NEPOOL OASIS Working Group and Co-Chair of the Joint Transmission Services Information Network Functional Process Committee. I also served for a brief time on the Electric Power Research Institute facilitated "How" Working Group on OASIS and the North American Electric Reliability Council facilitated Commercial Practices Working Group.

In 1997 I joined the firm of Brubaker & Associates, Inc. The firm includes consultants with backgrounds in accounting, engineering, economics, mathematics, computer science and business. Since my employment with the firm, I have filed or presented testimony before the Federal Energy Regulatory Commission in Consumers Energy Company, Docket No. OA96-77-000; Midwest Independent Transmission System Operator, Inc., Docket No. ER98-1438-000; Montana Power Company, Docket No. ER98-2382-000; Inquiry Concerning the Commission’s Policy on Independent System Operators, Docket No. PL98-5-003; SkyGen Energy LLC v. Southern

Company Services, Inc., Docket No. EL00-77-000; Alliance Companies, et al., Docket No. EL02-65-000, et al.; Entergy Services, Inc., Docket No. ER01-2201-000; Remedying Undue Discrimination through Open Access Transmission Service, Standard Electricity Market Design, Docket No. RM01-12-000; Midwest Independent Transmission System Operator, Inc., Docket No. ER10-1791-000; NorthWestern Corporation, Docket No. ER10-1138-001, et al.; Illinois Industrial Energy Consumers v. Midcontinent Independent System Operator, Inc., Docket No. EL15-82-000; Midcontinent Independent System Operator, Inc., Docket No. ER16-833-000; Midcontinent Independent System Operator, Inc., Docket No. ER17-284-000; and Midcontinent Independent System Operator, Inc. and Ameren Services Company Docket No. ER18-463-000. I have also filed or presented testimony before the Alberta Utilities Commission, the California Public Utilities Commission, the Colorado Public Utilities Commission, the Connecticut Department of Public Utility Control, the Florida Public Service Commission, the Idaho Public Service Commission, the Illinois Commerce Commission, the Indiana Utility Regulatory Commission, the Iowa Utilities Board, the Kentucky Public Service Commission, the Louisiana Public Service Commission, the Michigan Public Service Commission, the Missouri Public Service Commission, the Montana Public Service Commission, the Nevada Public Utilities Commission, the New Mexico Public Regulation Commission, the Council of the City of New Orleans, the Oklahoma Corporation Commission, the Public Utility Commission of Texas, the Virginia State Corporation Commission, the Wisconsin Public Service Commission, the Wyoming Public Service Commission, Federal District Court and various committees of the Illinois, Missouri and South Carolina state legislatures. This testimony has been given regarding a wide variety of issues including, but not limited to, ancillary service rates, avoided cost calculations, certification of public convenience

and necessity, class cost of service, cost allocation, fuel adjustment clauses, fuel costs, generation interconnection, interruptible rates, market power, market structure, off-system sales, prudency, purchased power costs, resource adequacy, resource planning, rate design, retail open access, standby rates, transmission losses, transmission planning, transmission rates and transmission line routing.

I have also participated on behalf of clients in the Southwest Power Pool Congestion Management System Working Group, the Alliance Market Development Advisory Group and several committees and working groups of the Midcontinent Independent System Operator, Inc. ("MISO"), including the Congestion Management Working Group; Economic Planning Users Group; Loss of Load Expectation Working Group; Market Subcommittee; Michigan Transmission Studies Task Force; Planning Subcommittee; Regional Expansion, Criteria and Benefits Working Group; Resource Adequacy Subcommittee (formerly the Supply Adequacy Working Group); and Reliability Subcomittee. I am currently a member of the MISO Advisory Committee in the end-use customer sector on behalf of industrial customer groups in Illinois, Louisiana, Michigan and Texas. I am also the past Chairman of the Issues/Solutions Subgroup of the MISO Revenue Sufficiency Guarantee ("RSG") Task Force.

In 2009, I completed the University of Wisconsin-Madison High Voltage Direct Current ("HVDC") Transmission course for Planners that was sponsored by MISO. I am a member of the Power and Energy Society ("PES") of the Institute of Electrical and Electronics Engineers ("IEEE").

In addition to our main office in St. Louis, the firm also has branch offices in Corpus Christi, Texas; Louisville, Kentucky; and Phoenix, Arizona.

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TO WHOM AVAILABLE

Available to Industrial Customers taking service at Transmission or Subtransmission voltage whose Premises are located adjacent to existing electric facilities having Transmission or Subtransmission capacity sufficient to meet the Customer's requirements. Customer shall contract for a definite amount of electrical demand which shall not be less than 10,000 kWs. The Company shall not be obligated to supply electrical Energy in excess of the definite amount specified in the contract.

For multiple Premises held under common ownership or by affiliates (as defined in Indiana Code § 23-1-43-1) and having the same qualifying service voltage, Interval Data Recorder (IDR) meters with 5-minute interval telemetry capability at those Premises can be aggregated for billing purposes if at least one of those meters has a load of 10,000 kWs or more for the last 12 months. Transmission charges will be applied to the gross energy consumption (not netted with potential outputs from other qualifying meters) of each individual IDR meter. Netting for Transmission Charges will be allowed for multiple meters at each Customer Premise. The specific IDR meters that will be applied for aggregation will be specified in the contract.

Customer's elections under Rate 531 Tiers 2 and/or Tier 3 shall occur in a window between the day after NIPSCO's compliance filing in each applicable Rate Case to thirty (30) days thereafter. Customer recognizes that in order to implement Tier 3, customer may need to install software including a security certificate to be provided by NIPSCO. The Customer and Company agree to work together during the 30 day period to achieve implementation.

CHARACTER OF SERVICE

The Company will supply metered Transmission or Subtransmission service to the extent of the Transmission capacity available from its electric supply lines, at such frequency, phase, regulation and voltage as it has available at the location where service is requested.

The Customer, at its own expense, shall furnish, supply, install and maintain, beginning at the point of delivery, all necessary equipment for transmitting, protecting, switching, transforming, converting, regulating, and utilizing said electric Energy on the Premise of the Customer.

The Customer will also supply in accordance with plans and specifications furnished by the Company and at a mutually agreed upon location on the Customer's property, suitable buildings, structures, and foundations to house and support the metering and any protecting, switching, and relaying equipment that may be supplied by the Company.

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CHARACTER OF SERVICE (Continued)

Customers electing Tier 2 and Tier 3 service shall contract for and specify a Tier 2 and Tier 3 Contract Demand for each affected Premise or aggregated Premises under this Rate Schedule. Tier 2 and Tier 3 service shall by default be curtailable. Customers electing service under Tier 2 and Tier 3 of this Rate Schedule shall specify the firm portion of their Tier 2 and Tier 3 Contract Demand for each affected Premise or aggregated Premises that the Customer intends to exclude from MISO Curtailment. Customers shall also meet the applicable Load Modifying Resource (LMR) requirements pursuant to MISO's Tariff Module E-1 or any successor if firm capacity is not purchased or otherwise procured as allowed under Tier 2 and Tier 3. If a Customer's elected service under this Rate Schedule results in curtailable demand under Tier 2 and Tier 3, the Customer shall provide information necessary to satisfy these requirements, including information demonstrating to Company's satisfaction that the Customer has the ability to reduce load to any firm capacity within Tier 1, Tier 2, and Tier 3.

Any Applicant requiring service differing from that to be supplied by the Company as herein provided shall provide proper converting, transforming, regulating or other equipment upon Applicant's Premise and at Applicant's expense. (See Company Rule 3 for the Company's standard voltages.)

SERVICE TIERS

Tier 1: Firm Service

The default Tier 1 Contract Demand election is 30,000 kW with an option to elect above or below that amount down to 10,000 kW. The firm Energy is calculated on an hourly basis. This service is subject to applicable Riders as identified in Appendix A.

Tier 2: Non-Firm Market Price Service

The Customer's Tier 2 Contract Demand is the Customer's Planning Reserve Margin Requirement using the Company's forecasted Coincident Peak demand for the Customer less the Customer's Tier 1 Contract Demand election and any Tier 3 Contract Demand election by the Customer. This service is subject to applicable non-production Riders as identified in Appendix A. Customer will take all Energy under this Tier 2 service at Day-Ahead LMP at the applicable Company Load Zone (NIPS.NIPS)) plus Transmission Charges contained within this Rate Schedule. By September 30 of each year, the Company will share with the Customer its Planning Reserve Margin Requirement, forecasted Coincident Peak demand and the supporting documentation for the values. Customer shall have 30 calendar days to dispute these values. The Company will make all reasonable efforts to resolve any such disputes; however, as the Market Participant, the Company is responsible for all forecasted needs and its subsequent forecast methodology, which is subject to audit by MISO. Company will submit the Customer's Planning Reserve Margin Requirements and Coincident Peak demand on November 1 of each year to comply with MISO's Resource Adequacy Requirements pursuant to the current Annual Resource Adequacy Construct or any successor constructs including a Seasonal Resource Adequacy Construct.

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SERVICE TIERS (Continued)

Tier 2 Contract Demand is firm only to the extent that it is supported by Customer-procured capacity. A customer may procure capacity outside of MISO Zone 6, provided that any charges related to that capacity including delivery into NIPSCO's zone are directly assigned to the responsible customer and that the customer accepts responsibility for such charges. NIPSCO, as the Market Participant, will register as an LMR at MISO that portion of a Customer's Tier 2 Contract Demand for which capacity is not procured through MISO's PRA or contracted through a third party. Such portion of a Customer's Tier 2 Contract Demand is non-firm, subject to MISO Curtailment. Customers must meet all applicable LMR requirements pursuant to MISO's Tariff Module E-1 or any successor for this portion of their Tier 2 Contract Demand.

Tier 3: Non-Firm Third Party Generation Service

Customer may elect a Tier 3 Contract Demand up to Customer's Planning Reserve Margin Requirement using the Company's forecasted Coincident Peak demand for the Customer less the Customer's Tier 1 firm Contract Demand election. To the extent a Customer declines to elect the Tier 3 Contract Demand to which it is entitled under this Rate Schedule, it must elect to take Tier 2 Contract Demand. If the Customer elects to take any Tier 3 Contract Demand, NIPSCO, as the Market Participant, will register that Customer as an Asset Owner at MISO. Tier 3 service is subject to applicable non-production Riders as identified in Appendix A. If, under the MISO Asset Owner framework, a Customer has not arranged for any third party Energy with NIPSCO as the contracting Market Participant, Customer will take all Energy under this Tier 3 service at market price (LMP at the applicable Company Load Zone (NIPS.NIPS) plus all applicable MISO market settlement charges plus the Transmission Charge contained within this Rate Schedule. Customer will be responsible for all market settlement charges incurred by either NIPSCO as the Market Participant or the Customer as Asset Owner for any third party Energy or Capacity arrangements including, but not limited to, transmission charges to deliver energy. MISO Market Portal access will be provided as required to carry out MISO Asset Owner functions. All settlements associated with energy offers and demand bids will be passed through to the Customer. By September 30 of each year, pursuant to the current Annual Resource Adequacy Construct or any successor constructs including a Seasonal Resource Adequacy Construct, the Company will share with the Customer its Planning Reserve Margin Requirement, forecasted Coincident Peak demand and the supporting documentation for the values. Customer shall have 30 calendar days to dispute these values. The Company will make all reasonable efforts to resolve any such disputes; however, as the Market Participant, the Company is responsible for all forecasted needs and its subsequent forecast methodology, which is subject to audit by MISO. Company will submit the Customer's Planning Reserve Margin Requirements and Coincident Peak demand on November 1 of each year to comply with MISO's Resource Adequacy Requirements pursuant to the current Annual Resource Adequacy Construct or any successor constructs including a Seasonal Resource Adequacy Construct.

Tier 3 Contract Demand is firm only to the extent that it is supported by Customer-procured capacity.

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SERVICE TIERS (Continued)

A customer may procure capacity outside of MISO Zone 6, provided that any charges related to that capacity including delivery into NIPSCO's zone are directly assigned to the responsible customer and that the customer accepts responsibility for such charges. NIPSCO, as the Market Participant, will register as an LMR at MISO that portion of a Customer's Tier 3 Contract Demand for which capacity is not procured through MISO's PRA or contracted through a third party. Such portion of a Customer's Tier 3 Contract Demand is non-firm, subject to MISO Curtailment. Customers must meet all applicable LMR requirements pursuant to MISO Tariff Module E-1 or any successor for this portion of their Tier 3 Contract Demand.

METER FLOW AND CURTAILMENT ORDER

Definition of meter flow shall be defined as follows:

Meter Flow	Service
↓	Applicable service taken under Rider 576
	Tier 1: Firm Service
	Tier 2: Market Price Service
	Tier 3: Third Party Generation Service

The above meter flow is for Energy only. For MISO Curtailments, the meter flow shall be defined as follows:

Meter Flow	Service
↓	Tier 2 and Tier 3: Non-Firm
	Applicable service taken under Rider 576

MISO CURTAILMENT AND FIRM CAPACITY OPTIONS

The Company shall dispatch Customers for MISO Curtailments at its own discretion in accordance with the limitations specified under this Rate Schedule and the Company Rules. The Company shall register the portion of all Customer Contract Demand above its Tier 1 level as an LMR with MISO and shall be subject to MISO Curtailments under this Rate Schedule. Customer shall meet the applicable LMR requirements pursuant to MISO's Tariff Module E-1 or any successor. A Customer may elect to reduce all or part of its LMR obligation by procuring capacity in the MISO PRA or capacity through third party arrangements, at the Company's applicable zone defined within MISO's PRA pursuant to the current Annual Resource Adequacy Construct or any successor constructs including a Seasonal Resource Adequacy Construct. If Customer elects to reduce all or a portion of its LMR obligation through MISO's PRA, NIPSCO will self-schedule (price-taker) such capacity on the Customers behalf. Customers that fail to meet the requirements of a LMR or do not otherwise procure capacity will be subject to any capacity replacement/deficiency charges, and any penalties incurred as a result of maintaining Customer's Resource Adequacy needs.

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MISO CURTAILMENT AND FIRM CAPACITY OPTIONS (Continued)

Notwithstanding anything to the contrary in this rate schedule, Tier 2 and Tier 3 Customers will be provided at least two (2) hours advanced notice of MISO Curtailments. Tier 3 Customers will be able to determine the parameters associated with registration as a LMR, other than curtailment notice time, pursuant to the MISO Tariff and BPM. NIPSCO may add additional time to the LMR notification time to allow for the communication of any MISO curtailment event consistent with MISO LMR requirements.

In the event of a material change in circumstances due to a force majeure, or otherwise, that effects the ability of a Customer to comply with part or all of its LMR obligations with MISO, the Customer shall immediately notify the Company. The Company will in turn notify MISO of a need to change the Customer's LMR registration. Modifications to LMR intra to the MISO Planning Year may trigger replacement capacity provisions within the MISO Tariff and may require the Customer to procure replacement capacity or pay MISO capacity deficiency charges / penalties.

MISO ASSET OWNER REGISTRATION

For a Customer electing Tier 3 service, registration will follow MISO's quarterly network model update cycle. During quarterly network model updates, the Company will request registration of a CP Node which is required for participation as an Asset Owner under this Rate Schedule. The CP Node will be mapped to MISO EP Nodes in the same manner as the NIPS.NIPS CP Node to the extent model modifications are allowed under MISO Rules. Refer to the market registration section of the MISO BPM for details on the data required to register.

COMMUNICATIONS, METERING, TELEMETRY, HARDWARE, AND SOFTWARE REQUIREMENTS

The Company shall specify a communications plan, which includes a revenue quality meter and all implementation and operational software required under this Rate Schedule. It is the Customer's responsibility to comply with that plan. The Customer will pay for the installed cost of additional metering, telemetry, hardware and software development, certificates, and licensing fees that may be required to facilitate service under this Rate Schedule. All such metering shall be compliant with any applicable current and future MISO and/or IURC requirements, including the potential of meter capture on a 5 minute basis. The Customer shall provide the Company with next day remote interrogation of the meter on an hourly level. The Customer may elect to install its own metering, with the Company reserving the right to inspect the equipment and own the equipment once it is installed. At the Customer's request, metering may be installed by the Company and invoiced at the installed cost to the Customer. Estimated costs of metering and equipment shall be provided prior to installation by the Company, but the Customer shall be responsible for the actual costs of the equipment and installation.

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DEMAND BIDS

For a Customer electing Tier 3 service, the Customer will have the ability to submit Day-Ahead Demand Bids for a portion or all of their Tier 3 daily demand through the MISO Market Portal. Day-Ahead Demand Bids not received by MISO in accordance with the MISO BPM will be settled at Real Time LMPs and assessed any applicable additional MISO charges. Refer to the Demand Bid section of the MISO BPM for details on the requirements of the Demand Bid.

MISO COMMUNICATIONS

For a Customer electing Tier 3 service, all clearing, pricing and settlement activity will be available on the MISO Market Portal. Revenue quality meter data will be interrogated by the Company on a daily basis and submitted by the Company to MISO on behalf of the Customer.

MISO SETTLEMENTS

For a Customer electing Tier 3 service, MISO Settlement Statements are posted daily by MISO to the MISO Market Portal. The Customer shall obtain the MISO Settlement Statements from the MISO Market Portal. The Customer shall be responsible for the review of the Customer's MISO Settlement Statements. All charges reflected on the Customer's MISO Settlement Statements will be the Customer's responsibility and are payable to the Company on a weekly basis. MISO Settlement Statement charges will be determined by the Customer's Day-Ahead Demand Bid (at Day-Ahead LMP) and the imbalance between the Customer's Day-Ahead Demand Bid and the Customer's actual metered Demand (at Real-Time LMP). Any imbalance between the Customer's Day-Ahead Demand Bid and the Customer's actual metered Demand will also be assessed any applicable MISO charges including a Revenue Sufficiency Guarantee charge. MISO Settlement Statements will also include the Customer's share of Market Uplift charges and an administrative fee that is charged by MISO to support the operation of the market. The Customer's MISO Settlement Statements will follow the settlement timeline that is outlined in the MISO BPM, which may also include special resettlements that are deemed necessary by MISO. Refer to the MISO BPM for details on the MISO Settlement Timeline and Settlement Charge calculations.

DISPUTES

For a Customer electing Tier 3 service, the Customer has the right to dispute any MISO charges. The Customer, through the MISO Market Portal, will provide all required data to MISO to support the dispute. The Customer shall notify the Company of any filed disputes and disposition by MISO within 24 hours of such notification. Notification of disputes shall include a copy of the dispute submitted by the Customer along with any correspondence between the Customer and MISO including, but not limited to, the final resolution of the dispute. Notification shall be remitted to the Manager, Market Settlements of the Company. Third party energy and capacity suppliers may also represent the industrial customer's interests in the event of a dispute with MISO, FERC, or the IURC. At a

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DISPUTES (Continued)

minimum, NIPSCO should be kept informed of the dispute process and may need to be a party to the process.

Disputes that have been denied by MISO may be disputed through the MISO Alternative Dispute Resolution (ADR) process in accordance with MISO Rules. The Company as the Market Participant must file ADR disputes on the Customer's behalf as currently Asset Owners cannot file an ADR. The Customer must provide written notification in compliance with the timelines established by Attachment HH of the MISO Tariff to the Company requesting the Company to proceed with the mechanism available to resolve these disputes outside of the judicial or administrative agency proceedings. This would include informal dispute resolution, or formal mediation or arbitration. The Company will make a good faith effort to prosecute the dispute. The Company will provide the Customer an initial preliminary estimate for costs associated with the ADR. Customer must submit payment in accordance with the estimate established if the Customer wishes to pursue the ADR at MISO. The written notification shall be remitted to the Manager, Market Settlements of the Company.

The hierarchy as it stands allows an Asset Owner to file the dispute with MISO. If the dispute is denied and the Customer wants to pursue it further, the Customer needs to request NIPSCO to file an ADR on its behalf with MISO. If the Customer is unsatisfied with MISO's decision, it can pursue a complaint with FERC on its own.

It is the responsibility of the Customer to pay all assessed MISO Settlement Statement charges to the Company when due at the time of assessment. Any necessary adjustments to the settlement amounts will be made by MISO after dispute resolution. Refer to the MISO BPM for details on the requirements of the Dispute and ADR process.

REGISTRATION

Customers electing non-firm service and or registration as an LMR will provide all required data to the Company per MISO's Resource Adequacy BPM. The Company may request additional data as requested by MISO to support any and all Resource Adequacy compliance requests. MISO's capacity Planning Year is June 1 through May 31 pursuant to the current Annual Resource Adequacy Construct or any successor constructs including a Seasonal Resource Adequacy Construct. All required information must be entered prior to due dates to ensure capacity positions are established. Once the PRA has cleared, modifications can be made per limitations and penalties as outlined in MISO's Tariff Module E-1.

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REGISTRATION (Continued)

The following table provides an overview of Tier requirements. All requirements and dates are pursuant to MISO's Tariff Module E-1 or any successor and may be modified by MISO. Customer shall provide required information to the Company ten (10) business days prior to MISO Planning Resource Timeline in accordance with MISO BPM-011, Appendix K:

Requirement	Tier 2	Tier 3
Coincident Peak Demand forecast, Non-Coincident Peak, and energy forecast		X
Existing Load Modifying Resource/Energy Efficiency Resource must be submitted for approval	X	X
New Load Modifying Resource/Energy Efficiency Resource registration to be considered for inclusion in FRAP must be submitted for approval		X
New Load Modifying Resource/Energy Efficiency Resource must be submitted for approval	X	X
Planning Resource Auction offer window is open		X
Planning Resource Auction offer window is closed		X
Planning Resource Auction results posted		X

DETERMINATION OF AMOUNT OF ELECTRIC SERVICE SUPPLIED

The electric service to be supplied under this Rate Schedule shall be measured as to Maximum Demand, Energy Consumption and kVAR by an IDR to be installed by the Company.

RATE

Rates charged for service rendered under this Rate Schedule are based upon the measurement of electric Energy at the voltage supplied to the Customer.

After aggregation of Customer's Premises, Customer Energy delivered onto the Company's Transmission or Subtransmission system at an integrated hourly level shall be paid to the Customer at the Real Time LMP at the Company's Load Zone.

The electric service and Energy supplied hereunder shall be billed under a three-part rate consisting of a Demand Charge, Energy Charge, and Transmission Charge, and applicable Riders as identified in Appendix A. The Demand Charge, Energy Charge, and Transmission Charge are as follows:

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RATE (Continued)

Demand Charge

Tier 1

$27.45 per kW per month

Energy Charge

Tier 1

$0.037151 per kWh for all kWhs used per the month.

Tier 2

All kWhs used above the specified Tier 1 Firm Contract Demand shall be subject to an Energy Charge equal to the Day Ahead LMP for the Company's Load Zone, if Customer does not have a Tier 3 Contract Demand. If Customer has a Tier 3 Contract Demand, all kWhs used above the specified Tier 1 Firm Contract Demand not in excess of Tier 2 Contract Demand shall be subject to an Energy Charge equal to the Day Ahead LMP for the Company's Load Zone.

Tier 3

All kWhs used above the specified Tier 1 and Tier 2 Contract Demand shall be subject to MISO Settlement Charges related to a Customer's Asset Owner activity.

Transmission Charge

$0.011493 per kWh for the gross Energy consumed at each IDR, netted by Premise (Tier 1, Tier 2, and Tier 3).

Adjacent Affiliate Qualifying Facility Premise Transmission Charge

$0.003448 per kWh for the gross Energy transferred from a premise with behind the meter generation to an adjacent premise held under common ownership or by affiliates (as defined in Indiana Code § 23-1-43-1). If the Customer's premises were served under NIPSCO's prior Rate 732 on October 31, 2018, the gross Energy transferred from a premise will be determined by netting in the applicable monthly billing period the amount of self-generated Energy and metered consumption.

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DETERMINATION OF DEMAND

The Customer's Demand of electric Energy supplied shall be determined for each half-hour interval of the month and said demand in kWs for each half-hour interval shall be two (2) times the number of kWhs recorded during each half-hour interval. The phrase "half-hour interval" shall mean the thirty (30) minute period beginning or ending on a numbered clock hour as indicated by the clock controlling the metering equipment.

The Customer's current integrated Demand shall be determined for each MISO settlement period for load as the total kWh recorded during that MISO settlement period multiplied by the ratio of 60 minutes to the total number of minutes in that MISO settlement period.

DETERMINATION OF LAGGING kVAR

The Customer's requirements in Lagging kVAR shall be determined for each half-hour interval of the month and shall be two (2) times the number of Lagging kVAR Hours recorded during each half-hour interval. No effect whatsoever shall be given hereunder to Customer's leading kVAR, if any.

ADJUSTMENT FOR CUSTOMER'S PEAK HOURS LAGGING kVAR

The number of kVAR shall be computed each month for a Power Factor of eighty-five percent (85%) Lagging using as the basis of said computation, the Customer's Maximum Demand for the month during the Peak Period hours thereof.

If the Customer's Maximum Peak Period Requirement in Lagging kVAR for the month is greater than the number of kVAR at a Power Factor of eighty-five percent (85%) Lagging, as determined above, an amount equal to the product of $0.32 times said difference shall be added to the Customer's Bill.

If the Customer's Maximum Peak Period Requirement in Lagging kVAR for the month is less than the number of kVAR at a Power Factor of eighty-five percent (85%) Lagging, as determined above, an amount equal to the product of $0.32 times said difference shall be deducted from the Customer's Bill.

The Customer agrees to control and limit Maximum Off-Peak (weekdays 22:00 – 06:00 CST, all weekend hours, and all hours during NERC holidays) Period Requirement in Lagging kVAR so that, as related to the Maximum Off-Peak Period kW Demand, it shall not exceed in ratio or numerical proportion the ratio of the Maximum Peak Period Requirement in Lagging kVAR and the Maximum Peak Period kW Demand; except that if such Maximum Off-Peak Period kW Demand is less than the Maximum Peak Period kW Demand, the Customer's Maximum Off-Peak Period Requirement in Lagging kVAR may equal the Customer's Maximum Peak Period Requirement in Lagging kVAR.

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CUSTOMER LOAD INFORMATION

If requested by the Company, the Customer shall cooperate with the Company by furnishing the Company in writing on or before the first day of July each year a statement of the Customer's estimates of the Customer's future load on the Company by months for a subsequent period of thirty (30) months.

On a daily basis, the Customer shall also make a good faith effort to provide the Company in writing with an accurate hourly load forecast for three (3) to ten (10) days into the future. The Customer shall make best efforts to ensure its hourly load forecast reflects actual operational and outage plans and provide updates to the Company to the extent hourly load forecasts change materially.

The Customer's dispatcher shall cooperate with the Company's dispatcher by furnishing, from time to time, such load information and operating schedules which will enable the Company to plan its market operations.

The accuracy of the information herein called for is not guaranteed by the Customer and reliance thereon shall be at the sole risk of the Company.

Failure by the Customer to provide requested information on an ongoing basis may result in Customer being moved to another Rate Schedule upon ninety (90) days' notice from the Company to Customer.

CUSTOMER'S FAILURE TO COMPLY WITH REQUESTED MISO CURTAILMENT

A Customer is deemed to have failed to comply with a MISO Curtailment when the Customer's current integrated Demand, as measured by the meters installed by the Company (netted across aggregated Customer Premises, if applicable), has not decreased to a level of the sum of the Customer's specified Tier 1, firm Tier 2 and firm Tier 3 Contract Demands.

If a Customer fails to comply with a MISO Curtailment, the Customer shall be liable for any charges and/or penalties from any governmental agency(ies) having jurisdiction or duly applicable organization including MISO, FERC, NERC and Reliability*First* for failure to comply with a MISO Curtailment. Penalties and charges may be, but are not limited to, penalties associated with disqualification as a LMR to the extent such penalties are specifically invoked on the Company due to the failure of the Customer to comply with the Curtailment.

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GENERAL TERMS AND CONDITIONS OF SERVICE

1. Contract

Any Customer requesting service under this Rate Schedule shall enter into a written contract for an initial period of not less than five (5) Contract Years. The Customer maintains the ability to cancel the contract if the entire Premise is closing. For customers who are aggregating Premises, if one Premise closes, the Customer may modify its Tier 1 Contract Demand with 12 months' notice, but it may not go below 10,000 kWs. For a Customer partially closing a Premise, the Customer may modify its Tier 1 Contract Demand with 12 months' notice, but it may not go below 10,000 kWs. The Customer may increase the Tier 1 firm Contract Demand election with five (5) years' notice and a period of not less than five (5) Contract Years. On a quarterly basis, consistent with the MISO Commercial Model timing, a Customer may elect to move all, or a portion, of its election(s) under Tier 2 and Tier 3 between such.

Notwithstanding the foregoing, contracts under this Rate Schedule shall terminate in accordance with Rule 5.8 of the Company Rules.

2. Third Party Contracts

Any Third Party Contracts for energy under Tier 3 and/or capacity under Tier 2 and/or Tier 3 shall include, at a minimum, the following provisions:

i. identify NIPSCO as the Market Participant for the retail customer at MISO;
ii. reference NIPSCO's market-based rate authority with FERC;
iii. clearly state the Rate 531 customer remains a retail customer of NIPSCO;
iv. indemnify NIPSCO from any financial or performance obligations under any physical energy or capacity agreement (the terms of any such agreement will link to the end use customer, who will wholly bear the risk associated with its contractual obligations);
v. incorporate relevant provisions of the Rate 531 tariff;
vi. all pricing provisions in any agreement may be redacted by the customer; however NIPSCO reserves the right to request and be provided redacted information if determined necessary; and
vii. any information shared with NIPSCO shall be subject to a confidentiality agreement.

3. Default Schedule

Notwithstanding the foregoing conditions of service under this Rate Schedule, service shall be subject to the provisions of Rule 5.9 of the Company Rules.

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GENERAL TERMS AND CONDITIONS OF SERVICE (Continued)

4. Customer Disqualification

Under this Rate Schedule and / or applicable Riders to this Rate Schedule, any Customer that is found to be engaging in activity that is determined to be a violation of market manipulation or antitrust rules / laws may be subject to disqualification from eligibility for Tier 3 of this Rate Schedule if any such activity disqualifies the Customer from meeting obligations set forth under this Rate Schedule. Penalties and charges may be, but are not limited to, penalties associated with disqualification as a LMR, any market damages, or private party damages. By taking service under this Rate Schedule, the Customer agrees to fully participate in any investigation into possible violation(s).

Any Customer that is disqualified from eligibility for service under Tier 3 service shall have all of its Tier 3 Contract Demand moved to Tier 2 with all of the Customer's Tier 2 Contract Demand, including any pre-existing Tier 2 Contract Demand of the Customer, covered with capacity through MISO's PRA and replacement capacity provisions within the MISO Tariff and may require Customer to procure replacement capacity or pay MISO capacity deficiency charges / penalties. The Customer will not be eligible for Tier 3 service and LMR registration for a period of five (5) years. After the five (5) year period, the Customer may be allowed to return to Tier 3 under this Rate Schedule or successor.

RULES AND REGULATIONS

Service hereunder shall be subject to the Company Rules, IURC Rules, and MISO Rules.