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May 22, 2015

Ms. Mary Jo Kunkle
Michigan Public Service Commission
7109 W. Saginaw Highway
P.O. Box 30221
Lansing, Michigan 48909

**Re: MPSC Case No. U-17767**

Dear Ms. Kunkle:

Attached for filing in the above-referenced matter, please find the Direct Testimony, Qualifications and Exhibits of Alexander J. Zakem on behalf of Energy Michigan, Inc. Also attached is a Proof of Service indicating service on the parties.

Thank you for your assistance in this matter.

Sincerely yours,

VARNUM

Timothy J. Lundgren

Digitally signed by Timothy J. Lundgren
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Date: 2015.05.22 14:22:11 -04'00'

Timothy J. Lundgren

TJL/ba

c. ALJ
Parties

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STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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| | | |
|---|---|---|
| In the matter of the application of<br>DTE ELECTRIC COMPANY<br>for authority to increase its rates, amend<br>its rate schedules and rules governing the<br>distribution and supply of electric energy, and<br>for miscellaneous accounting authority.<br>_____________________________________ | )<br>)<br>)<br>)<br>)<br>)<br>) | Case No. U-17767 |

**DIRECT TESTIMONY**

**OF**

**ALEXANDER J. ZAKEM**

**ON BEHALF OF**

**ENERGY MICHIGAN, INC.**

**Q. Please state your name and business address.**

A. My name is Alexander J. Zakem and my business address is 46180 Concord, Plymouth, Michigan 48170.

**Q. On whose behalf are you testifying in this proceeding?**

A. I am testifying on behalf of Energy Michigan, Inc. ("Energy Michigan")

**Q. Please state your professional experience.**

A. Since January of 2004 I have been an independent consultant providing services to various clients, including members of Energy Michigan.

From March 2002 to December 2003, I was Vice President of Operations for Quest Energy, an alternative energy supplier in Michigan. My responsibilities included the overall direction and management of Quest's power supply to its retail customers. This included power supply planning, development of customized products, negotiation with suppliers, planning and acquiring transmission rights, and scheduling and delivery of power. It also included managing risk with respect to market price movements and variation of customer loads.

Prior to retiring from Detroit Edison in 2001, from 1998 to 2001, I was the Director of Power Sourcing and Reliability, responsible for purchases and sales of power for mid-term and long-term periods, planning for generation capacity and purchase power needs, strategy for and acquisition of transmission rights, and related support for regulatory proceedings.

Additional experience, qualifications, and publications are contained in Exhibit EM-1 (AJZ-1).

**Q. Have you testified as an expert witness in prior proceedings?**

A. Yes. I have testified as an expert witness in several proceedings before the Michigan Public Service Commission ("Commission"), on topics such as standby rates, retail rates and regulations, recovery and allocation of costs and revenues, and the effects of rate restructuring. I have also testified before the Federal Energy Regulatory Commission. Case citations are in Exhibit EM-1 (AJZ-1).

**Q. Are you sponsoring any exhibits?**

A. Yes. I am sponsoring the following exhibits:

| | |
|---|---|
| Exhibit EM-1 (AJZ-1) | Qualifications |
| Exhibit EM-2 (AJZ-2) | Split of Uncollectibles – with Uncollectibles as Proposed by DTE |
| Exhibit EM-3 (AJZ-3) | Split of Uncollectibles – with No Change in Allocation of Uncollectibles |
| Exhibit EM-4 (AJZ-4) | Comparison of Capacity Prices |

**Q. What is the purpose of your testimony?**

A. DTE Electric functions as both an electric distribution company ("EDC") and a load serving entity ("LSE"). It provides distribution service to all retail customers in its service area, both Full Service customers and Electric Choice ("EC") customers, and it provides power supply service to Full Service customers. As an EDC, it should treat all customers – both Full Service customers and Electric Choice customers in the Electric Choice program – equally and fairly regarding rules, distribution services, and charges affecting EC customers.

The purpose of my testimony is to identify and explain the DTE Electric proposals affecting Electric Choice customers, and to recommend changes that make the proposals more equitable and fair.

**Q. What proposals and rules are you going to address?**

A. I will address the following:

1. Incentive compensation – DTE's proposed incentive compensation to be paid for by customers.

2. Separation of uncollectibles into distribution and power supply components.

3. DTE's proposed change in allocation of uncollectibles.

4. DTE's perceived "shortfall" of capacity: (a) evidence from MISO and (b) effects on DTE's policies for Electric Choice and on the economic analysis of the Renaissance plant purchase.

5. Value of low cost energy in cost-of-service methods.

6. Capacity benefit and pricing of the proposed expanded D8 interruptible rate.

7. Line extension allowance for Full Service versus Electric Choice distribution customers.

## 1. Incentive Compensation

**DTE's proposal for including incentive compensation in revenue requirements should be modified.**

**Q. What is your opinion on DTE Electric's incentive compensation proposal?**

A. DTE's proposal for including incentive compensation in revenue requirements should be modified. DTE proposed to include in its revenue requirement the incentive compensation under several programs: the Executive Compensation Program, the Annual Incentive Plan ("AIP"), the Rewarding Employees Plan ("REP"), and the Long Term Incentive Plan ("LTIP"). Company witness Mr. Jeffrey C Weupper explains these plans in his direct testimony, and concludes:

> Thus, the Company's incentive compensation costs should be included in the revenue requirements adopted by the Commission in this proceeding as reasonable and prudently incurred costs. *[Weupper direct testimony, page 56, lines 1-3.]*

The DTE incentive compensation plans are shown in Exhibit A-20 (AMC-1), Schedules L1-L4, and the expense of the programs are shown on Schedule L5, column k. Expenses for the Executive Compensation Program apparently are included in the other three programs. Incentive compensation for "top five" executive officers is excluded from the expenses that DTE proposes to be included in revenue requirements:

> While the Company believes that all its compensation expenses are reasonable, the Company has excluded the variable compensation expense for DTE's top five executive officers. This results in the exclusion of approximately $12.2 million of expenses. This exclusion is reflected on Exhibit A-3, Schedule C1, line 19, which is supported by Witness Uzenski. *[Weupper direct testimony, page 44, lines 7-11.]*

The inclusion of incentive compensation in rates – and how much should be included – is a policy issue for the Commission that has been argued, re-argued, ordered, and re-ordered over many years.

There is nothing inherently good or bad with inclusion of "incentive compensation" in rates for utility services. My perspective is that if incentive compensation is going to be included in rates and tied to utility performance, then rate recovery should be allowed only in the rates of customers that are specifically affected by specific performance criteria, and in an amount that reflects a reasonable sharing of the benefits of superior performance that would not have occurred without the incentive.

**Q. Do the proposals in Exhibit A-20 reasonably reflect the sharing of benefits of superior performance, if they were to be included in the rates of Electric Choice customers for distribution services?**

A. No, in several areas they do not. The two main deficiencies are (a) failure to tie performance to benefits to customers – which affects all customers, not just Electric Choice – and (b) failure to separate distribution service benefits from power supply service benefits that EC customers do not receive – which affects EC distribution customers.

Regarding the failure to tie performance to customer benefits, Exhibit A-20, Schedule L5 shows that 62.8% of the incentive expense is tied to various financial goals (column k, line 14 / line 52), including return to shareholders, balance sheet "health," return on equity, DTE Electric operating earnings, earnings per share, operating cash flow, and DTE Energy corporate operating earnings per share.

For any rate-paying customer to pay a bonus to a utility for increasing earning per share, total return to shareholders, and the other financial goals is illogical and violates the principle of paying for a shared benefit. Such a system forces ratepayers to reward the utility for making them pay more, as the earning are earned on the ratepayers backs, so to speak. Moreover, increased earning per share benefits stockholders, not customers. Therefore, if there is to be a payment to utility employees for meeting financial goals that benefit stockholders, the payment should come out of stockholder earnings, not customer rates.

**Q. What is your recommendation?**

Consequently, my recommendation is that if the Commission chooses to approve an incentive compensation mechanism, then the "financial" portion shown on Exhibit A-20, Schedule L5, should be excluded.

**Q. The other portions of Exhibit 20 relate to customer satisfaction, employee "engagement," and operating excellence. How would you assess these parts of the proposal, and what are your recommendations?**

A. First, electric and gas incentives should be separated and only the incentive expenses for electric should be included in this proceeding. Exhibit A-20, Schedule L3, lines 39-40 show that a small part of the total compensation is for performance of the gas distribution system. That part should be eliminated.

Second, as I noted above, DTE Electric has failed to separate distribution service benefits from power supply service benefits. Specifically, four of the five "operating excellence" measures shown on Exhibit A-20, Schedule L5, lines 36-46 relate directly to power plants. Full service customers take *both* power supply service and distribution service, while EC customers take *only* distribution service. Full service customers benefit from improved plant outage rates and reduction in plant expenses. Electric Choice customers do not, because they are paying another supplier for power supply services, including services from the Midcontinent Independent System Operator (MISO).

Therefore, EC customers should pay only for performance of the distribution system, which measure is shown on Exhibit A-20, Schedule L5, lines 37-38.

Third, in regard to "Employee Engagement – Gallup" shown on Exhibit A-20, Schedule L5, line 26, if this is the result of some type of morale or attitude survey, then it should be excluded, as it is not directly tied to the distribution or power supply services for which customers pay.

***2. Separation of Uncollectibles***

***Costs related to distribution and power supply services should be separated.***

**Q. What are "uncollectibles" ?**

A. The term "uncollectibles" in the context of cost of service is jargon for unpaid electric utility bills. If a customer does not pay a bill, then the utility is short of money needed to cover its costs. Historically, the annual amount of uncollectibles has been able to be estimated reasonably well enough so that it can be included in authorized rates as another cost. The amount of uncollectibles can change in a rate case. In this proceeding, DTE has proposed a change in the *method* by which the total amount of uncollectibles is allocated to the major rate classes.

**Q. How are uncollectibles presently included in rates?**

A. At present, *all* uncollectibles are included in the *distribution* part of DTE's rates. (See Exhibit A-13, Schedule F1.5, page 1 of 14, line 4.)

**Q. Do uncollectibles include only distribution costs?**

A. No. Obviously, if a customer does not pay a bill, that bill includes *both* distribution *and* power supply charges. As a result, total uncollectibles include compensation to the utility for both distribution and power supply costs.

**Q. Should all uncollectibles be included only in the distribution part of DTE's rates?**

A. No. Because uncollectibles include both distribution and power supply charges, uncollectibles should be separated in a reasonable way into a distribution portion and a power supply portion. The distribution portion should be included in distribution rates, and the power supply portion should be included in power supply rates.

DTE provides separate distribution and power supply services and charges separately for each. Thus, available information allows uncollectibles to be divided up into the respective service components.

Distribution customers should pay a fair share of uncollectibles in their distribution rates, and power supply customers should pay a fair share of uncollectibles in their power supply rates. Dividing up total uncollectibles into a distribution portion and a power supply portion, a simple task, is an equitable way to charge customers for uncollectibles.

Including all uncollectibles only in distribution rates, as DTE does presently, means that customers of other power suppliers – Alternate Electric Suppliers – who take only distribution service from DTE are compensating DTE for power supply costs and subsidizing DTE's power supply customers who do not pay their power supply charges. Distribution and power supply are *separate services* with separate costs and separate charges, and the components of those charges should not be mixed. In fact, proper separation of distribution and power supply costs is one of the reasons for doing a careful cost of service study.

**Q. Has a similar separation been done before?**

A. Yes. In Consumers Energy's last general rate case U-17087, the subsidy for the E-1 rate was allocated to various rate classes, and then separated within each rate class into a distribution portion and power supply portion, which were then included in the respective components of the rate design revenues. I am proposing a similar method for the DTE uncollectibles.

**Q. How would the separation of uncollectibles into distribution and power supply components be done for DTE?**

A. The information on the two components is available, and the method is straightforward. DTE has allocated the total uncollectibles to major rate classes and asserts that the amount allocated to each rate class is the responsibility of that rate class. The uncollectibles represent unpaid bills for each class and include both distribution charges and power supply charges. DTE also provides the distribution revenues and power supply revenues for each rate class.

If the Commission approves DTE's proposal to change the allocation method for uncollectibles, I propose that the uncollectibles that DTE allocates to each major rate class be divided up within the class according to the proportion of distribution revenues and power supply revenues for that class.

For example, assume that $10 of uncollectibles is allocated to a rate class, and assume that distribution revenues are $30 million and power supply revenues are $70 million. Then 30% of the total class revenues of $100 million are distribution revenues. Consequently, 30% of the uncollectibles – $3 – should be put into the distribution rates, and 70% -- $7 – into the power supply rates.

**Q. Why is it reasonable to divide up the uncollectibles within a rate class according to the distribution and power supply revenues within the class?**

A. In its proposed cost of service, DTE has allocated uncollectibles to major rate classes according to the rate class source of the uncollectibles. DTE already divides up all the charges in the rate by distribution (called "delivery") and power supply. DTE categorizes revenues from those charges as distribution and power supply. If a customer does not pay a bill, then both the distribution part and the power supply part are short. In total, considering tens of millions of dollars of uncollectibles, the proportion of distribution and power supply charges in the unpaid bills should reasonably reflect the rate designs for the class and therefore reflect the total distribution and power supply revenues for the class.

**Q. Do you have an exhibit that shows how the uncollectibles should be separated into distribution and power supply components?**

A. Yes. Exhibit EM-2 (AJZ-2) shows how to separate the uncollectibles into distribution and power supply components and how to include the components into the rate design targets for the major rate classes.

Exhibit EM-2 (AJZ-2) assumes that the Commission approves DTE's proposal to change the current allocation method of uncollectibles. Another exhibit, which I will explain later, assumes that the present allocation method continues.

The top box of Exhibit EM-2 (AJZ-2), lines 1-7, shows source numbers from DTE – distribution revenues, power supply revenues, and uncollectibles. Sources are noted on the exhibit. On Exhibit EM-2 (AJZ-2) the uncollectibles total of $52,799 on line 6, column (B), and DTE's rate class allocations in columns (C) – (F) match DTE's proposed allocations on Exhibit A-13, F-1.5, page 1 of 14, line 4, with the three voltage levels of the Primary class aggregated.

The middle box, lines 8-19, accomplishes three tasks: (1) it backs out the uncollectibles from the distribution rates, (2) it calculates the percent of distribution and power supply revenues, and (3) it separates the uncollectibles according to the percent of distribution and power supply revenues.

The bottom box, lines 20-25, adds back the distribution and power supply components of uncollectibles into the distribution revenues without uncollectibles and into the power supply revenues.

DTE has various methods of designing rates for sub-classes of the major rate classes, and there would be no change in these methods.

**Q. Does the split of distribution and power supply uncollectibles that you propose result in any changes in total uncollectibles allocated to the rate class or in total revenues for the rate class?**

A. No. Total uncollectibles allocated to each major rate class remain the same – line 6 equals line 19 in Exhibit EM-2 (AJZ-2). And the total of distribution plus power supply revenues for each major rate class remain the same – line 4 equals line 24.

**Q. What if the Commission rejects DTE's proposal to allocate uncollectibles by source rate class, and instead continues the present allocation method?**

A. If the Commission rejects DTE's proposal and the present method of allocating uncollectibles continues, then one more intermediate step needs to be done. The present method allocates total uncollectibles across all major rate classes based on a cost of service percentage method – essentially by class revenue requirement. Consequently, the uncollectibles revenue that is allocated to a *particular* class by the present method does not reflect the distribution and power supply proportions of only the particular class to which the revenue is allocated, but rather reflects the proportions that are in total uncollectibles.

However, since the uncollectibles for each class are known – as a result of DTE's proposal – a weighted average of the distribution and power supply proportions in each rate class can be calculated for the total company and then applied to the uncollectibles allocated to each class. Exhibit EM-3 (AJZ-3) shows how this should be done.

Exhibit EM-3 (AJZ-3) is similar to Exhibit EM-2 (AJZ-2) with an additional box on lines 21-28 that calculates the weighted average proportion of distribution and power supply uncollectibles and splits the uncollectibles allocated to each major class by this proportion.

Again, total uncollectibles allocated to each major rate class remain the same – line 23 equals line 28 in Exhibit EM-3 (AJZ-3). And the total of distribution plus power supply revenues for each major rate class remain the same – line 4 equals line 33.

The total uncollectibles of $52,799 would remain unchanged, and the allocations to the rate classes as approved by the Commission's order would be inserted on line 23, columns (B) – (F).

**Q. What is your recommendation to the Commission?**

A. If the Commission accepts DTE's proposal to change the way uncollectibles are allocated to the rate classes, then I recommend that the Commission order that the uncollectibles included in rates be separated into distribution and power supply components according to the method shown in Exhibit EM-2 (AJZ-2).

If the Commission rejects DTE's proposal to change the way uncollectibles are allocated to the rate classes and instead maintains the current allocation, then I recommend that the Commission order that the uncollectibles included in rates be separated into distribution and power supply components according to the method shown in Exhibit EM-3 (AJZ-3).

Separation of uncollectibles into distribution and power supply begins *after* the uncollectibles are allocated to the rate classes. There is no change in total uncollectibles, and no change in the way the Commission decides to allocate uncollectibles to the rate classes. Once the Commission decides, then the appropriate method of separation can be applied.

### *3. DTE's Proposed Change in Allocation of Uncollectibles*

***Deny DTE's proposal***
***and continue to allocate as a company-wide overhead.***

**Q. DTE is proposing to change the way uncollectibles are allocated to rate classes. What method is DTE proposing, and why?**

A. DTE witnesses state:

> The Company is proposing to change the basis for allocating the costs associated with uncollectible expense. In the past, DTE Electric has allocated these costs to rate classes based on a cost of service percentage basis. A more appropriate assignment of uncollectible expense is to allocate these costs to the customer classes that cause them. As further described by Witness Heiser, the Company is proposing to allocate uncollectible expense based on net write-offs by class. *[Stanczak direct testimony, page 22, lines 18-22.]*
>
> " . . . the proposed changes are consistent with Case No. U-17689." *[Stanczak direct testimony, page 23, line 2.]*
>
> The proposed allocation of customer-related cost is consistent with past practice except that uncollectibles are allocated to classes based on their historic contribution to net write-offs instead of the former practice of allocating uncollectible expense to classes in proportion to their cost of service. *[Heiser revised direct testimony, page 8, lines 18-21.]*
>
> The costs associated with uncollectible expense are currently assigned based on each class's cost of service (excluding the cost of uncollectibles). A method that more accurately reflects cost causation is to measure write offs net of recoveries caused by each major class and assign the uncollectible expense on that basis. I use net write-offs as the basis for allocating uncollectible expense because uncollectibles are not recorded by customer class. *[Heiser revised direct testimony, page 25, line 22, to page26, line 2.]*

**Q. Do customer classes cause uncollectibles?**

A. No, they do not. Customers cause uncollectibles, not customer classes – that is, the amount of uncollectibles of a class is not determined by the electric use characteristics of the class. Contrary to the principle of cost causation, DTE's proposal puts the burden of compensation for uncollectibles on the customers in the class who do *not cause uncollectibles at all*, but rather pay their bills.

Further, DTE's proposal for allocation of uncollectibles is contrary to its rationale for changing to voltage level groups for allocation of distribution costs. DTE witness Mr. Heiser states:

> For distribution, I think grouping customers by the voltage level at which they are served is a more meaningful basis for distinguishing one class from another than the current practice of basing class groupings on the end-use of the electricity delivered. For the distribution system the costs to serve two customers at the same voltage level are similar regardless of how they use [of] the energy being delivered. [*Heiser revised direct testimony, page 24, lines 4-9.*]

Yet, DTE wants to bill uncollectibles to the group of customers who use energy in the same way as the group of customers who do not pay their bills, simply because they use energy in the same way, *e.g.*, for residential or commercial purposes.

A residential customer is no more responsible for – or the "cause" of – a residential customer down the block who did not pay the DTE bill than is the grocery store on the corner or the hospital a mile away. And vice versa.

**Q. What is the solution to the allocation of uncollectibles?**

A. The solution is apparent and simple – no change in allocation method. The utility must recover uncollectible expenses. Uncollectibles are a company-wide overhead, independent of the electric use of rate classes. Thus the uncollectibles should be allocated in a general and equitable way to all rate classes to be paid by all customers. The current method of allocating uncollectibles to rate classes does this. DTE has not provided any reason to change.

I recommend that the Commission deny DTE's proposal to change the allocation method for Uncollectibles and continue to allocate the costs as a company-wide overhead.

The only change I am proposing for uncollectibles is to separate the distribution and power supply components within the class to which uncollectibles are allocated, independent of the method by which they are allocated, explained in Section 2 of my testimony, above.

## 4 (a). Perceived "Shortfall" of Capacity

### Evidence from MISO supply and pricing is contrary to perceived "shortfall."

**Q. Does DTE believe that there will be a "shortfall" of capacity in the MISO region?**

A. Apparently so. DTE witness Mr. Stanczak states:

> In MISO's most recent "Long-Term Resource Adequacy Update" dated

> October 22, 2014, MISO indicates that the Central & North Regions are expected to have a 2.3 GW Resource Requirement shortfall in 2016, with an additional 1.1 GW shortfall increase due to the Covert Power Plant going to PJM Interconnection in2016. Specifically, in Zone 7 (Michigan excluding Upper Peninsula), where DTE Electric's service territory is located, a 3.0 GW Resource Requirement shortfall is expected in 2016. *[Stanczak direct testimony, page 15, lines 12-18.]*

And DTE witness Ms. Irene M. Dimitry states:

> The most recent survey conducted by MISO in October 2014 indicates the MISO north and central regions will have a reserve margin shortfall of 3.4 GW in 2016 as coal plants are retired due to the Mercury and Air Toxic Standards (MATS) regulation. Michigan's Lower Peninsula (MISO Local Resource Zone 7) accounts for the majority of the shortfall with 3.0 GW short. *[Dimitry direct testimony, page 5, lines 21-25.]*

**Q. What is your perspective?**

A. DTE Electric appears to have misinterpreted evidence of the capacity supply/demand situation, both availability of physical supply in Michigan and market prices, and consequently to have overstated the existence, if any, of a "shortfall."

MISO did create a summary presentation comparing forecasted load to presently known capacity, by zone, dated June 5, 2014. It updated this presentation and entitled it "Long-Term Resource Adequacy Update, October 22, 2014 ("October 22 Report"). (See https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/BOD/System%20Planning%20Committee/2014/20141022/20141022%20Syste m%20Planning%20Committee%20of%20the%20BOD%20Item%2004%20Long %20Term%20Resource%20Adequacy%20Assessment.pdf)

However, MISO has modified its characterization of the "shortfall" in lower Michigan. MISO explained the situation to its board of directors at the October 22, 2014 meeting of the board's System Planning Committee. The publication *MW Daily* reported:

> "Michigan is where there is the most turbulence in terms of generation committed to the MISO market," Claire Moeller, MISO executive vice president of transmission and technology, said during the meeting. <u>To address that shortfall, Moeller stressed, does not necessarily mean a fresh spate of generation construction is necessary in the next couple of years</u>.
>
> "At this point, <u>it's not a lack of physical capacity</u> but a lack of commercial deals to contract for that capacity," he said.
>
> "In the short run, <u>the notion that Michigan has to build 3,000 MW of capacity is not the impression I want to leave you with</u>."
>
> [*MW Daily, October 22, 2014. Emphasis added. http://www.platts.com/latest-news/electric-power/louisville-kentucky/lower-michigan-electric-power-capacity-deficit-21437818*]

**Q. Why do you think that DTE has misinterpreted the MISO October 22 report?**

A. The DTE witnesses have quoted a couple of numbers from the October 22 Report. To understand what the numbers mean or don't mean, one has to understand the context of the MISO report and the processes that contributed to the quantification of surplus or shortfall in the report. I will explain briefly. Factors include:

a. <u>The static nature of MISO's report to the North American Electric Reliability Corporation ("NERC").</u>

MISO is required by the NERC to provide various types of information. One of the requirements is to compare a long-term load forecast to existing and known planned generation capacity. The difference shows how much additional capacity would be needed. It is important to recognize that while the future load is generally *trended up* based on past history and economic forecasts, the supply is *static* except for known additions.

MISO's actual expectations are different – it expects that the "shortfalls" it reports to the NERC *will change*. The MISO October 22 Report, on page 7, which shows <u>only the North/Central region</u>, with a 2.3 GW shortfall, states:

> This slide shows a **preliminary forecast** of a 10-year period, as is required for the NERC Long Term Reliability Assessment. MISO fully expects that **these figures will change significantly as future capacity plans are solidified** in the future by load serving entities and state commissions. [*MISO October 22 Report, page 7. Emphasis in original*.]

b. <u>MISO omitted aggregating its new zones 8 and 9 – called "MISO South" – with previous zones 1 through 7 – called "MISO Central and North."</u>

On page 6, the October 22 Report shows a surplus of 2.5 GW in MISO South (zones 8 and 9) and a shortfall of 2.3 GW in MISO Central and North (zones 1-7). In its various presentations, MISO has <u>not included</u>

zones 8 and 9 in the netting of the surpluses and shortfalls of the other zones. This is why the number of "2.3 GW shortfall" is mistakenly thought to be the MISO net position, rather than "0.2 surplus" (= +2.5 South less -2.3 Central/North), excluding the effect of the Covert plant.

MISO's estimate of transmission transfer capability from MISO South to MISO Central and North is about 4 GW. *["Midwest ISO Presentation to Entergy Regional State Committee Work Group," November 17, 2010, page 13*.] A MISO presentation at the February 6, 2014, SAWG meeting put the estimated transfer capability for capacity purposes at 1.5 to 3.0 GW. [*"OMS/MISO Resource Adequacy Survey Update," January 31, 2014, page 2, in SAWG meeting materials of February 6, 2014. https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/SAWG/2014/20140206/20140206%20SAWG%20Item%2004%20OMS-MISO%20Survey%20Update.pdf*]

c. MISO is not counting all known and planned resources.

There are three types of known and planned resources that MISO is not counting.

1. MISO is not counting resources that were labeled "low certainty" resources in the Organization of MISO States (OMS) survey. These resources have *not* declared an intention to retire, but they are not included in either the retirements or in usable resources. MISO puts this number at

2.6 GW for 2016. [*MISO "MTEP14" Report, December 2014, Section 6.2, page 147. https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/BOD/BOD/2014/20141211/20141211%20BOD%20Item%20IXA%20MTEP%2014%20for%20Board%20Approval.pdf*]

2. Also on June 5, 2014, at the SAWG committee meeting, MISO showed an "unused capacity" report. These were resources that were not counted, for a number of different reasons displayed in the report. The total was 3,615 MW (3.615 GW). While a good portion of the 3,615 MW is out of the game, another good portion of these resources might well be available or become available in 2016. For example, 1,014 MW of capacity with "insufficient transmission reservation"; 460 MW of capacity composed of units less than 50 MW; and part of 525 MW that was shown as "retirement" but part of which (unknown to the public at present) could end up still running as SSR units. [*SAWG meeting materials, June 5, 2014, "2014-2015 PRA, Unused Capacity by Reason," June 5, 2014, page 2. https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/SAWG/2014/20140605/20140605%20SAWG%20Item%2005%20Unused%20Capacity.pdf*]

3. MISO excludes planned resources which are under study in the MISO interconnection queue but do not have a signed interconnection agreement,

and also excludes planned resources that are not in the interconnection queue.

d. The Planning Reserve Margin ("PRM") decreased after the October 22 Report was published.

The PRM used in the October 22 Report was 14.8% ICAP (installed capacity) and 7.3% UCAP (unforced capacity), the numbers for Planning Year 2014-15. The current numbers for Planning Year 2015-16 are 14.3% ICAP and 7.1% UCAP. MISO's tally in the October 22 Report is expressed in ICAP GW. The decrease of 0.5% of the ICAP PRM, applied to approximately 124 GW of MISO demand for 2015 results in a decrease in required nominal capacity of about 0.6 GW.

**Q. Does MISO report the effects of the above to the NERC?**

A. Yes, MISO does. However, MISO does not put all these factors into its presentations to the public, and consequently the public perception can be mistakenly formed by picking up only a few very visible number in MISO's presentations, without understanding the qualifications and contexts that go with the numbers.

When MISO considers all of the factors, it is not reporting a "shortfall" to the NERC. MISO's report to the NERC states:

> MISO is projecting that both the prospective and adjusted-potential margin will stay above the 14.8% planning reserve margin for the assessment period.
>
> The prospective margin includes both the low certainty resources identified in the Resource Adequacy survey, existing other capacity and resources that are currently under study in the MISO interconnection queue but do not have a signed interconnection agreement. The adjusted potential margin additionally includes resources that were identified in the Resource Adequacy Survey but are not currently in the MISO interconnection queue.
>
> It's important to note that while the anticipated margin does drop below the requirement MISO fully expects that the margin shortfall will change significantly as future capacity plans are solidified in the future by load serving entities and state commissions. This expectation is represented in both the prospective and adjusted-potential margin."
>
> [*MISO SAWG meeting materials, July 10, 2014, "Draft LTRA Narrative Review Language." Emphasis added. https://www.misoenergy.org/Library/MeetingMaterials/Pages/SAWG.aspx See, 2014, meeting 20140710, meeting materials.*]

**Q. Does lower Michigan currently have a "shortfall" of capacity?**

A. No. For the MISO Planning Year 2015-2016, which extends from June 1, 2015, through May 31, 2016, there is no "shortfall" in MISO Zone 7, which is the MISO area in the lower peninsula of Michigan. In fact, there is excess of capacity such that Zone 7 is actually exporting capacity for credit to other zones in MISO, as evidenced from MISO's recent capacity auction.

The MISO Planning Reserve Auction ("PRA") for 2015-2016 was completed and results published on April 14, 2015, subsequent to DTE filing testimony in this proceeding. The MISO report is entitled "2015/2016 Planning Resource Auction Results, April 14, 2015" ("MISO PRA Report").

*[Link:https://www.misoenergy.org/Library/Repository/Report/Resource%20Adequacy/AuctionResults/2015-2016%20PRA%20Results.pdf ]*

**Q. What does the MISO PRA Report show?**

A. The MISO PRA Report shows a capacity excess in lower Michigan for the 2015/2016 Planning Year – June 1, 2015 through May 31, 2016.

For Zone 7, lower Michigan, the MISO PRA Report page 8 shows that 23,559 MW within Zone 7 were accounted for in the PRA auction, the sum of 14,103 MW offers submitted and 9,456 Fixed Resource Adequacy Plans.

Zone 7 needs only 21,442 MW of capacity within the zone, the Local Clearing Requirement shown on page 6. Any additional capacity required to cover forecast load plus reserves can come from either within or outside Zone 7. This is the economic benefit provided by Zone 7's Capacity Import Limit of 3,813 MW, also shown on page 6. From the results of the MISO auction, Zone 7 lower Michigan presently has 2,117 MW more (= 23,559 – 21,442) than what MISO requires to be within Zone 7.

Further, Zone 7 lower Michigan presently has 881 MW more than the 22,678 MW required (Planning Reserve Margin Requirement) to cover *all* the load in Zone 7.

Finally, the MISO PRA Report shows that Zone 7 is actually *exporting* 837 MW of capacity, which is credited to fulfilling the capacity requirements of other zones in MISO.

**Q. What do the PRA results imply for the next Planning Year 2016/2017?**

A. The PRA results indicate an excess of about 1,000 MW for 2016/2017, not a "shortfall."

For 2015/2016, Zone 7 has 2,117 MW excess capacity compared to what MISO requires to be within Zone 7. Consumers Energy and DTE Electric plan to retire about 1,100 MW combined. That leaves about 1,000 MW excess capacity within Zone 7 for 2016/2017, not a 3,000 MW "shortfall."

**Q. Must Michigan have all capacity physically located within Michigan sufficient to provide capacity required for all Michigan electric load?**

A. No, not at all. That would be not only unnecessary, but also very costly.

It is the Local Clearing Requirement established by MISO that determines how much capacity must be physically located in Michigan. The Local Clearing Requirement accounts for the capability of the transmission system to import energy into zones. In MISO, all capacity is used to serve all load – no capacity is earmarked for specific loads. *Less <u>total</u> capacity is required when all zones share all capacity, compared to each zone building capacity to serve load within the* *zone without transmission interconnections.* It would be a serious economic and engineering error to ignore the value of transmission interconnections among the zones in MISO. A state policy of some sort of "energy independence" could be very costly to electric customers, yet with no benefit of better supply/demand reliability.

For example, if a state energy policy required capacity within Michigan to cover the Planning Reserve Margin Requirement of 22,678 MW, the difference of 1,236 MW above the present Local Clearing Requirement represents capacity that does not have to be built at all. At nominal cost between $1,000 per MW for natural gas combined cycle and $5,000 per MW for nuclear, the unneeded cost for Michigan ratepayers is between $1.2 billion and $6.2 billion.

If a state energy policy required Zone 7 lower Michigan to have internal capacity sufficient to serve all the load inside the zone *without* transmission interconnections, MISO would require more capacity, 25,255 MW, to be in the zone (MISO PRA Report, page 8, Local Clearing Requirement of 21,442 MW plus Capacity Import Limit of 3,813 MW). This would add an additional 2,546 MW above the Planning Reserve Margin Requirement presently required, representing unneeded costs for Michigan ratepayers of an additional $2.5 billion to $12.7 billion. Thus, total unneeded costs compared to the amount required by the Local Clearing Requirement would be about $3.7 billion to $18.9 billion.

If a state energy policy were to be predicated on a MISO "shortfall" of 3,000 MW compared to an actual surplus of 1,000 MW, the difference of 4,000 MW represents unneeded costs of between approximately $4 billion and $20 billion.

**Q. Has DTE made other interpretations of the amount and value of capacity available now and in the future?**

A. Yes. DTE's forecast of capacity prices may initially appear somewhat to go along with its perspective of a future "shortfall"; actual prices, however, are quite different, reflecting the absence of a "shortfall."

The MISO Planning Reserve Auction ("PRA") clearing price for 2014/2015 for Zone 7 (lower Michigan) was $16.75 per MW-day, equivalent to $6.11 per kW-year. The MISO PRA clearing price for 2015/2016 for Zone 7 was $3.48 per MW-day, equivalent to $1.27 per kW-year. Exhibit EM-4 (AJZ-4) compares MISO actual capacity prices with various prices used by DTE.

Exhibit EM-4 (AJZ-4), column (C) indicates that DTE has substantially overestimated the price of capacity in lower Michigan for the 2015/2016 Planning Year. DTE's interpretation of a MISO capacity "shortfall" has not been borne out by actual prices that reflect actual supply versus demand.

**Q. Do the DTE projected capacity prices in Exhibit EM-4 (AJZ-4) support an actual "shortfall" for lower Michigan in 2016?**

A. No. In spite of the DTE projected prices for 2016 being substantially above 2015 MISO actual prices, the DTE projected prices do not support a "shortfall" for 2016.

If there is insufficient capacity to satisfy the Local Clearing Requirement in a MISO zone or the forecast demand plus Planning Reserve Margin, then MISO will set the Auction Clearing Price to the "Cost of New Entry" – typically in the $85-95 per MW-year range – according to the MISO tariff. (See MISO Tariff, Module E-1, section 67A.7.1.c.ix.)

DTE's capacity price estimates are well below the MISO Cost of New Entry for Zone 7, which MISO set at $90.53 for the 2015/2016 Planning Year. (See Federal Energy Regulatory Commission Docket ER14-2808, MISO filing September 8, 2014, Attachment B.)

So, DTE's capacity price estimate for 2016, for example the $27.00 in its PSCR Plan shown on Exhibit EM-4 (AJZ-4), line 3, means that DTE is saying that it believes it will be ***able to purchase capacity in 2016*** for $27 per MW-year. This estimated price is 70% below the $90.53 price that would occur under a "shortfall."

DTE's estimated capacity prices as shown on Exhibit EM-4 (AJZ-4) could be more accurately characterized as believing there will be a reduced supply of excess capacity in the market, but not an actual "shortfall." It is not consistent, on one hand, to say there will be a "shortfall" of capacity and on the other hand, to say that one will be able to purchase capacity at well below the MISO market price that would occur if there were an actual shortfall.

**Q. What is your recommendation to the Commission?**

A. The above shows that DTE's conventional wisdom about capacity supply and prices is not supported by evidence from MISO. Policy actions based on the Company's perceptions of a "shortfall" could impose very large unneeded costs on Michigan ratepayers, as well as unneeded restrictions on Electric Choice. DTE states:

> However, should AESs not be able to arrange the required physical generation capacity required to serve their end use customers, DTE Electric may need to take additional steps in the future to protect its full-service customers, including, but not limited to, changes in its return to service rules. *[Stanczak direct testimony, page 11, lines 12-15.]*

I recommend that prior to any policy decisions that may be affected by a perception that there is or will be a shortage of capacity in Michigan – such as new rules for Electric Choice – that the Commission undertake a thorough study of the supply/demand situation both in MISO and in Michigan.

## 4 (b). Perceived "Shortfall" of Capacity

### Effects of perceived "shortfall" on DTE's policies for Electric Choice and on the economic analysis of the Renaissance plant purchase.

**Q. What is DTE's concern over the implications of a capacity "shortfall"?**

A. Apart from its obligation as a Load Serving Entity to meet MISO's requirement to procure sufficient capacity to cover its own load, DTE's principle concern over a potential "shortfall" appears to be the ability to procure capacity to cover any additional load from customers returning from Electric Choice to DTE full service.

**Q. Does DTE presently acquire capacity to cover the potential return of Electric Choice customers?**

A. No, it does not. Company witness Mr. Stanczak notes, "At this time, it is the Company's intention to buy, build, or enter into capacity contracts to acquire the required capacity to serve only full-service customers." *[Stanczak direct testimony, page9, lines 17-18.]*

**Q. If Electric Customers return to DTE full service, what does DTE say it will do?**

A. DTE certainly understands the requirement to hold sufficient capacity rights to satisfy MISO requirements. It appears concerned over the availability of capacity:

> If Electric Choice customers return to DTE Electric's full-service rates for economic or any other reason, DTE Electric will need to procure incremental capacity and energy to serve these customers. Procuring incremental capacity and energy may be difficult to obtain at a favorable price, <u>if it can be obtained at all</u>.
>
> Therefore, full-service customers would either be harmed by paying a

> share of the higher costs to procure incremental capacity, or worse, be subject to system interruption if no incremental capacity is available. *[Stanczak direct testimony, page 10, lines 7-13. Emphasis added.]*

**Q. If a customer switches from one supplier to another, is supply/demand reliability affected for either the former supplier or the new supplier?**

A. No, not at all. The reason is that MISO serves all customers – all load – using all resources. The act of a customer switch does not change the load, does not change the supply, and does not change the MISO dispatch. For supply/demand reliability, it makes no difference which LSE is responsible for procuring capacity for which customers.

When a customer leaves a former supplier, capacity required for that customer is no longer needed by the former supplier – essentially "freed up" – but is needed by the new supplier. There is no change in total capacity needed for total load.

MISO recognizes that the transfer of a customer from one LSE to another is a financial transaction, not a physical transaction. In retail access states such as Michigan, MISO allocates capacity costs to LSEs on a daily basis, at the Auction Clearing Price times the customer MWs served. When a customer switches from one LSE to another, MISO allocates more MW – and thus more capacity costs – to the new LSE and decreases the MW allocated to the former LSE. There is no need for the new LSE to find and acquire more capacity, nor is there a need for the former LSE to sell its extra capacity on the market. This continues through the end of the current MISO Planning Year. (See MISO Tariff, Module E-1, section 69A.1.2.)

For the next Planning Year, the quantity of capacity required by the former LSE and the new LSE would be different, by the amount of the customer load being switched. But again, there is no change in the total quantity of capacity available in the market or the total capacity required by the total load in MISO.

In short, customer switching, returning customers, exiting customers – none of these actions affects supply/demand reliability in MISO.

**Q. Could there be a risk of price uncertainty for the next Planning Year?**

A. Yes, there could be. To the extent that the new LSE becomes short on capacity hedges and to the extent that the former LSE becomes long on capacity hedges, each would face market price uncertainty on those amounts. The amount of capacity available in the market would not change, but each LSE might be buying more or selling more at a market price than it would otherwise have done.

It should be noted that in MISO, an LSE's ownership of physical generation provides a price hedge for capacity, but ownership does not function to provide greater or lesser supply/demand reliability to the customers of the LSE.

**Q. Does the physical location of an LSE's capacity resources matter, for supply/demand reliability purposes?**

No. For supply/demand reliability in MISO it does not matter which LSE owns or has the rights to which capacity. For example, Utility X in Indiana could own all the power plants now owned by DTE, and DTE could own power plants only in Indiana, and the supply/demand reliability of customers of DTE, of Utility X, and in fact in all of MISO would not be affected.

**Q. Does the acquisition of the Renaissance plant affect DTE's supply/demand reliability, Michigan's reliability, or MISO's reliability?**

A. If the Renaissance plant would continue as a MISO planning resource regardless of whether DTE purchased it or not, then the acquisition of the plant by any new owner would not affect the new owner's, Michigan's, or MISO's reliability. Again, who owns which plant does not affect supply/demand reliability.

The *ownership* of a plant, whether purchased or built, functions as a financial hedge against future market capacity prices. The creation of a new resource affects reliability, not who owns an existing resource.

**Q. How would DTE's perspective on a MISO or Michigan "shortfall" affect the economic analysis of the Renaissance plant?**

A. As is fairly standard analysis, the economics of the Renaissance plant were compared with a "base option" using the tool of net present value of the revenue requirements over a specified period of time. DTE witness Ms. Dimitry describes the evaluation process and the resulting economic benefit:

> The Base Plan option consists of covering the Company's capacity shortfall with market purchases and new plant(s) construction. *[Dimitry direct testimony, page 10, lines 1-2.]*
>
> The benefits considered in the evaluation of the plant purchase include additional capacity credits from the MISO market . . . ." *[Dimitry direct testimony, page 10, lines 5-6.]*
>
> Based on our evaluation, the purchase of the Plant compared with the base option, results in an increase of $4 million in the Net Present Value of Revenue Requirements (NPVRR) over the period of 2015-2020 for our customers, a reduction of $33 million in the NPVRR over the period of 2015-2025, a reduction of $94 million in the NPVRR over the period of 2015-2030 and a reduction of $122 million in the NPVRR over the period of 2015-2035. The purchase of Renaissance is expected to breakeven on a NPVRR basis within approximately the first six years. *[Dimitry direct testimony, page 16, line 24, to page 17, line 5.]*

Consequently, the assumptions about future market prices – capacity, energy, ancillary services – are important factors in assessing the economics of one capacity plan over another.

DTE's perception of a MISO "shortfall" is somewhat reflected in the assumed future capacity prices it uses. Exhibit EM-4 (AJZ-4) shows some of the assumed future capacity prices DTE has used, in comparison with MISO actual PRA prices for 2014 and 2015. As explained previously, DTE's estimate of future capacity prices for 2016 could more accurately be characterized as believing there will be a reduction of surplus capacity in the market, not a true "shortfall" situation in

MISO. Yet DTE's estimated capacity prices are substantially above historical experience and were well off the mark as indicated by the results for 2015.

**Q. What is your conclusion regarding DTE's perception of a MISO capacity "shortfall"?**

A. DTE's stated perception of a "shortfall" implies there could be insufficient capacity to serve all customers in Michigan, and consequently DTE's perception is affecting its outlook on Electric Choice policies, on acquisition of owned generation, and on expansion of interruptible rates (explained in section 6 of my testimony). Consequently it wants to reduce the uncertainty of future events.

The important conclusion for the Commission is that removal of uncertainty does not necessarily mean removal of risk. Restrictions on switching Electric Choice customers is a risk if future capacity prices are low while energy prices are high, which would enable DTE to increase energy sales to returning Electric Choice customers with little additional capacity costs. In such a situation, "returning customers" might be financially *favorable* to DTE and neutral to full service customers. Also, owning generation equal to 100% of capacity requirements may remove most of the effect of uncertainty of future capacity prices, but it does not remove the risk that the utility cannot take advantage of the market by buying capacity if DTE's capacity price projections end up significantly higher than actual.

**5. Value of low cost energy in cost-of-service methods.**

**Q. Are DTE's present rates cost based?**

A. According to DTE, present rates are cost based. Company witness Mr. Stanczak states: "Thus, based on historical cost of service and rate design methods, DTE Electric's rates are currently cost based." [*Stanczak direct testimony, page 14, lines 24-25*.]

**Q. DTE is proposing to change the allocation of production costs to rate classes from the current method of "12 CP 50-25-25" to "4 CP 100-0-0." What does this mean?**

A. These terms are shorthand for the method of allocating production costs. The "CP" designation refers to the number of months of coincident peaks that are used in allocation – 12 months or 4 summer months. The numbers following are the percentages of production costs that are allocated by contribution to the "CPs," by on-peak energy, and by total energy, respectively.

**Q. Is DTE's proposed 4 CP 100-0-0 the right answer, or what some call the "true" cost of service?**

A. Economists and engineers have been debating how to apportion the joint costs of capacity since the 1890s. *There is no unique "right" answer to how to allocate joint costs, and so there is no "true" cost of service.* Instead, the characteristics of energy use over time, including various peaks in energy use, are assessed to come up with support for a particular method of allocating production costs that the authority controlling the pricing of regulated utility service – in this situation, the Commission – deems to be *reasonable*.

The Commission has approved the methods of allocating costs that have resulted in DTE's present cost-based rates. Consequently, the present methods have been deemed reasonable.

A change in the apportionment of production costs entails a policy decision by the Commission, not a single right answer.

**Q. If DTE's rates are already cost based, what is the merit of proposing a different way of allocating costs?**

A. Certainly, a change of circumstances can affect what is deemed "reasonable" and so can justify a revision. Changes to cost structures the Commission has deemed "reasonable" have to be justified. If the reason for a change in a cost of service method is not adequately justified to the Commission, such a change can end up as nothing more than a device to favor specific customer groups, for example, high load factor customers, at the expense of other groups – a poorly disguised attempt to avoid the label "subsidy" by merely changing the method by which rate class "costs" are determined.

**Q. Are cost of service allocation methods the only way to apportion costs among customer groups?**

A. No. The *rate designs* within a major class also affect how much of the total costs that a customer group within the class bears. DTE has intentionally designed its newly proposed D11 rate to favor "high load factor" customers. DTE witness Mr. Stanczak states:

> In this proceeding, I have instructed Witness Block to design rates to customers within the primary rate class will typically pay a lower average rate than the class average.
>
> Therefore, within the primary rate class, there is an opportunity to appropriately reflect the value of high load factor customers through rate design. [*Stanczak direct testimony, page 21, lines 7-11.*]

And DTE witness Mr. Timothy A. Bloch states:

> As instructed by Company Witness Stanczak, I designed rate D11 to benefit high load factor customers.
>
> Under the proposed rate structure this is accomplished by a rate design with lower energy charges and higher demand charges. To that end, I set the power supply energy charges close to the Company's base fuel and purchased power rate. [*Bloch direct testimony, page 10, lines 7-11.*]

**Q. Do high load factor customers create lower capacity costs compared to load factor customers?**

A. The answer requires more precision. If considering only an existing generation portfolio with sunk costs, then obviously the more energy the portfolio produces the less per-unit capacity cost has to be collected in each unit of energy sold. In this sense, more use from existing capacity – which is what higher load factor means – results in a lower *average price*.

Going forward into the future, however, the perspective on whether future costs or future average prices will be higher or lower may be quite different. Going forward, higher load factor customers may or may not be cheaper to serve than lower load factor customers. This is due to the fact that a changed production portfolio in the future may contain *different types* of generation facilities at widely different investment costs that serve both customer types together, while the optimal portfolios for serving each separately may be quite different.

For example, increased load of 1,000 MW at 100% load factor – same load every hour of the year – may trigger the need for a new 1,000 MW nuclear plant, at a nominal $5,000 or so per kW of capacity. Increased load of 1,000 MW for air conditioning on summer days may trigger the need for twenty combustion turbines of 50 MW each, at a capacity cost of a tenth of the nuclear unit. So to conclude that high load factor always means lower capacity costs or lower average costs in the future may not be true.

The *cost* of a production portfolio is an essential component in its design, not just the number of MW. The example above illustrates that the conventional wisdom of higher load factor customers being cheaper to serve is *not always true when the specifics of the design of the production portfolio* are taken into account. It also illustrates that lower load factor customers, such as the additional 1,000 MW of summer air conditioning customers may be using the facilities *designed to serve them* in an economically efficient way.

**Q. Is the design of the proposed new rate D11, with its increased monthly on-peak billing demand component and its reduced on-peak and off-peak energy component, consistent with DTE's rationale that higher load factor customers use the system more "efficiently"?**

A. As explained previously, DTE's rationale is predicated on energy use of existing capacity resources. Capacity of existing resources is essentially the same for an entire year, and likewise the cost of service is based on *annual* costs.

However, the D11 rate design, which favors higher load factor customers at the expense of other customers, is based on *monthly billing demand* and monthly energy, not the customer's contribution to *annual peak* and annual energy. So the D11 rate design is focused only on customers with a high *monthly* load factor. A customer could exhibit consistent, high load factor use within each month of the year, yet still have large variations from month to month and thus have a *poor annual load factor*.

Consequently, rate D11's monthly load factor focus is not consistent with DTE's rationale of why high load factor customers should be favored with lower rates. If high load factor customers are to be favored, then the goal should be more use over the year based on existing capacity, not more use over a single month based on monthly billing demand.

**Q. Is there a remedy for the design of rate D11?**

A. One remedy is to keep the same balance of billing demand prices and energy prices as exist now in the component rates that were joined to make up the new D11 rate. These have been argued and ruled upon in past cases before the Commission.

Another remedy – if the Commission wants to favor high load factor customers – is to apply a 100% 12-month ratchet to the billing demand, the same as exists now for maximum demand. Then, the new rate will address the true high load factor customers that DTE argues deserve a lower rate, not just customers with high monthly load factors.

Lastly, the Commission should consider that the proposed D11 rate will apply to a variety of customers, not just the intentionally favored high load factor group. As explained previously, there is no single "right" cost of service – the result has to be reasonable for all customers, low and middle load factor customers as well as high load factor customers.

**Q. Should the Commission recognize the energy value of production facilities in the allocation methods that it will approve?**

A. The Commission has recognized the value of energy in its past decisions, for example a “75-25” split of allocation of production costs. There are reasons why energy value should be taken into account in allocation methods. Cost of service allocates *dollars, not MWs*, and consequently the dollar value of the particular design of the entire production portfolio should be taken into account, not just the MWs.

Four main factors, not just MWs, affect the design of a production portfolio: (1) total MW quantity, (2) ability to deliver energy in varying amounts over time, (3) costs – both investment and operating – and (4) risks.

*Higher fixed* investment costs can result in *lower variable* fuel costs, and therefore some of the value of the fixed investment costs is related to the ability of a facility to produce lower cost energy.

So the question becomes, should the allocation of investment *dollars* depend *only* on four summer peaks when a large part of the investment *cost* of the portfolio – for facilities like large nuclear and coal plants – is designed to produce low-cost energy year around?

Again, as stated previously, there is no single right answer. In my opinion it is reasonable for the Commission to recognize, in the cost allocation method that it approves for production plant, the *total value* of the portfolio to the various customer classes, including both the capacity and the energy value.

**Q. What are your recommendations to the Commission?**

A. First, if the Commission is to approve a change in rate design that favors higher load factor customers – at the expense of some other customer groups, since the total revenues must remain the same – the proposal should be justified with specific clarity. Is the change justified going forward, or only when applied to historical average sunk costs? And justification should not be based solely on a change in the method of allocating production costs, which would be circular reasoning.

Second, I recommend that the Commission consider the energy value of DTE's production portfolio in its policy decision on whether or not to change the method of allocating production costs.

## 6. Capacity benefit and pricing of the proposed expanded D8 interruptible rate.

**Q. Has DTE proposed a change in the D8 interruptible supply rate?**

A. Yes. DTE has proposed increasing the cap on the D8 interruptible supply rate, based on its perception of a "shortfall" of capacity.

> As an additional measure to address the anticipated resource adequacy capacity shortfalls in MISO Local Resource Zone 7 as discussed above, the Company proposes to increase the availability of service capacity

> available on Rate Schedule D8 from its current cap of 150 MW, to 250 MW. The current available 150 MW of capacity is fully subscribed. Customers have requested additional D8, but cannot avail themselves of this interruptible service without an increase in available D8 capacity. Therefore, I have instructed Company Witness Mr. Bloch to reflect the impact of this adjustment in Exhibit A-14, Schedule F3. 3. *[Dimitry direct testimony, page 18, line 21, to page 19, line 3.]*

Ironically, the D8 situation is very much like Electric Choice – customers are requesting to get on the rate, but are prevented from doing so because of a cap. Consequently, DTE proposes to increase the cap. Unlike for Electric Choice, DTE has not expressed concern over acquiring capacity if D8 customers return to firm service.

**Q. Aside from DTE's proposal to increase the cap on D8, are there other changes that should be made to the D8 interruptible rate?**

A. Yes. The discount for interruptible service should reflect the value of MISO capacity. The value of capacity is what the D8 rate provides compared to the standard firm service D11 rate.

MISO resource adequacy rules allow interruptible service to qualify as a "load modifying resource" and to be used to satisfy capacity requirements. The market value of an interruptible kW is the clearing price from MISO's annual Planning Reserve Auction. Therefore, the discount of the monthly demand change for D8 should reflect the MISO PRA clearing price.

**Q. What has DTE proposed as a discount for D8, and how does that discount compare to the MISO PRA clearing price?**

A. DTE's proposed standard D11 rate has a power supply demand charge of $15.14 per kW-month. The proposed D8 charge is $9.69 per kW-month. The difference of $5.45 per kW-month is equivalent to $65.40 per kW-year.

The 2015 MISO PRA clearing price for Zone 7 lower Michigan is only $1.27 per kW-year (Exhibit EM-4 (AJZ-4), line 1, column (C) ). Thus, DTE's proposed discount for the D8 interruptible rate is far in excess of the capacity value of interruptible load and therefore results in other customers subsidizing D8 customers.

Even considering DTE's high estimates of future capacity prices, the proposed D8 discount of $65.40 per kW-year is more than DTE's estimates until 2022 (Exhibit EM-4 (AJZ-4), lines 10 and 12).

**Q. What is your recommendation to the Commission?**

A. I recommend that the discount in the D8 monthly power supply demand charge, compared to the D11 monthly power supply demand charge, be set to one-twelfth of the MISO PRA annual clearing price for the MISO Planning Year, and that such discount be reset each June 1 at the beginning of the MISO Planning Year.

In this way, the D8 discount will reflect the true value of interruptible capacity, and as a result will eliminate any subsidy of D8 by other customers.

**7. Line extension allowance for Full Service versus Electric Choice distribution customers.**

**Q. Has DTE proposed any changes to it line extension allowances?**

A. Yes. DTE has revised the prices shown in the standard allowance table in section C6.2.(4)(a) of the proposed tariff (Exhibit A-15, Schedule G1, page 7 of 113).

**Q. Are there other changes that should be made to the standard allowance table?**

A. Yes. The standard allowance table applies to costs and credits for distribution service. However, specific allowances depend on whether a customer has or does not have a full service contract as well as on the length of the full service contract. "Full service" means power supply service in addition to distribution service. As a result, two customers may receive the same type of distribution service and same benefit from extension of distribution facilities, but end up paying different amounts.

Revenue from power supply service should not be used as a rationale for charging less for new distribution facilities. Power supply and distribution are separate services, and they should be priced by cost of service and charged for separately, without subsidy from one to the other and without discrimination among customers.

Electric Choice customers by definition do not take power supply services and consequently would receive a different line extension allowance compared to a full service customer, for the same service and facilities.

**Q. What is your recommendation to the Commission?**

A. In the table in C6.2.(4)(a), the caption "Full Service Contract Term, Years" should be replaced by "Distribution Contract Term, Years"; and the caption "No Full Service Contract" should be replaced by "No Distribution Service Contract."

**Q. Does this conclude your Direct Testimony?**

A. Yes, it does.

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## CONSULTANT – MERCHANT ENERGY AND UTILITY REGULATION

Provides strategies and technical expertise on competitive market issues, transmission issues, state and federal regulatory issues involving the electricity business, and associated legal filings. Scope includes the Midwest ISO Energy Market and Resource Adequacy, FERC proceedings on transmission and market tariffs, state rules for competitive supply, and negotiation of settlements.

## PRIOR POSITIONS: Quest Energy, LLC – a subsidiary of Integrys Energy Services

**Vice President, Operations** **March 2002 to December 2003**

Responsible for the planning, acquisition, scheduling, and delivery of annual power supply and transmission, to serve competitive retail electric customers.

- ***Power Planning*** **--** Designed and negotiated customized long-term power contracts, to reduce power costs and exposure to spot energy prices.
- ***Transmission*** **--** Revamped transmission strategy to reduce transmission costs.
- ***Load Forecasting*** **--** Instituted formal short-term forecasting process, including weather normalization.
- ***Risk Management*** **--** Developed summer supply strategy including call options to minimize physical supply risk at least cost. Instituted probabilistic assessment of forecast uncertainty to minimize transmission imbalance costs.
- ***Contract Management*** – Negotiated and recovered liquidated damages for power supply contracts. Included cost of transmission losses into customer contracts.
- ***Operations Capability*** **--** Expanded the Operations staff. Oversaw daily activity in spot market purchases. Instituted back-up capability, including equipment and processes, enabling the company to schedule and deliver virtually all power during the August 2003 blackout in the Midwest.

**PRIOR POSITONS : DTE Energy / Detroit Edison — 1977 to 2001**

**Director, Power Sourcing and Reliability** **May 1998 to April 2001**

Director of group responsible for monthly, annual, and long-term purchases and sales of power for Detroit Edison, including procuring power for the summer peak season.

- ***Planning*** **--** Planned summer power requirements for Detroit Edison, including mix of generation, option contracts, hub purchases, load management, and transmission, which balanced and optimized physical risk and financial risk.

- ***Contract Management*** – Established decision, review, and approval process for evaluation and execution of power transactions, including mark-to-market valuation.

- ***Execution*** **--** Executed summer plans, contracting annually for purchased power and transmission services. Directed negotiations for customized structured contracts to provide the company with increased operating flexibility, dispatch price choices, and delivery reliability.

- ***Risk Management*** – Developed an optimizing algorithm using load shapes to minimize corporate exposure to volatile power prices. Developed a hedging strategy to fit power purchases to the corporation's risk tolerance level.

- ***Acquisitions*** -- Team leader for acquisition of new peakers.

- ***Settlements*** -- Negotiated and settled liquidated damages claims.

**Relevant prior positions within Detroit Edison**

| ***Position*** | ***Organization*** | ***Time Period*** |
|---|---|---|
| **Director, Special Projects** | **Customer Energy Solutions** | **Apr 97 to May 98** |

Leader of several special projects involving the transformation of the corporation's merchant energy functions into competitive business units, including merger explorations and the start up of DTE Energy Trading (DTE's power marketing affiliate).

Directed filings to the Federal Energy Regulatory Commission to establish DTE Energy Trading as a power marketer and to gain authority for sales, brokering, and code of conduct. The FERC used DTE's flexible utility/affiliate code of conduct as precedent for rulings for other power marketers.

| | | |
|---|---|---|
| **Director, Risk Management** | **Huron Energy (temp affiliate)** | **Jan 97 to Apr 97** |

Leader of team responsible for competitive pricing of wholesale structured contracts and for acquiring risk management hardware and software to support risk management policy. Prepared Board resolutions to implement risk management policy.

**Director, Contract Development** **Customer Energy Solutions** **Jan 96 to Dec 96**

Leader of team that formulated a business strategy for the corporation in competitive power marketing. Team leader on project evaluating an existing steam and electricity contract, recommending and gaining Board approval for revamping the corporation's Thermal Energy business and strategy.

**Project Director** **Executive Council Staff & Corporate Strategy Group** **Jan 91 to Dec 95**

Project leader for competitive studies, including business risk, generation pooling, and project financing in the merchant generation industry. Team member and/or team leader for analyses of merger and acquisition opportunities

**Special Assignment** **Executive Council Staff** **Mar 90 to Dec 90**

Special assignment related to long-term industry strategies and mergers and acquisitions.

**Pricing Analyst** **Marketing / Rate** **Aug 82 to Mar 90**

Developed, negotiated, and implemented an innovative standby service tariff. Testified as an expert witness in regulatory proceedings and in state legislative hearings.

**Engineer** **Resource Planning** **Aug 79 to Dec 81**

Member of the company's electric load forecasting team, responsible for SE Michigan energy and peak demand forecasting, and for risk analysis. Developed the company's first residential end-use forecast model.

**PRIOR POSITIONS:** **<u>Prior to DTE Energy</u>**

Lear Siegler Corporation, ACTS Computing division, systems analyst and programmer from January 1973 to July 1977.

**EDUCATION:** M. A. in mathematics, University of Michigan, 1972
B. S. in mathematics, University of Michigan, 1968

**MILITARY:** U. S. Army, September 1968 to June 1970.
Viet Nam service from June 1969 to June 1970.
Honorably discharged.

**PROFESSIONAL:** Member, Engineering Society of Detroit (1979-present)

**PUBLICATIONS & PAPERS:**

- "Competition and Survival in the Electric Generation Market," published in *Public Utilities Fortnightly*, December 1, 1991.
- "Measuring and Pricing Standby Service," presented at the Electric Power Research Institute's "Innovations in Pricing and Planning" conference, May 3, 1990.
- "Assessing the Benefits of Interruptible Electric Service," presented at the 1989 Michigan Energy Conference, October 3, 1989.
- "Principles of Standby Service," published in *Public Utilities Fortnightly*, November 24, 1988.
- "Progress in Conservation," a satirical commentary published in *Public Utilities Fortnightly*, October 27, 1988.
- "Comparing Utility Rates," published in *Public Utilities Fortnightly*, November 13, 1986.
- "Uncertainty in Load Forecasting," with co-author John Sangregorio, published in *Approaches to Load Forecasting*, Electric Power Research Institute, July 1982.

**PREVIOUS TESTIMONY:**

- Michigan Public Service Commission, U-17735
- Michigan Public Service Commission, U-17689
- Michigan Public Service Commission, U-17688
- Michigan Public Service Commission, U-17429
- Michigan Public Service Commission, U-17087
- Michigan Public Service Commission, U-17032
- Michigan Public Service Commission, U-16794
- Michigan Public Service Commission, U-16566
- Michigan Public Service Commission, U-16472
- Michigan Public Service Commission, U-16191
- Michigan Public Service Commission, U-15768.
- Michigan Public Service Commission, U-15744.
- Federal Energy Regulatory Commission, Docket No. EL04-135 & related dockets.
- Michigan Public Service Commission, U-12489.
- Michigan Public Service Commission, U-8871.
- Michigan Public Service Commission, U-8110 part 2.
- Michigan Public Service Commission, U-8110, part 1.
- Michigan Public Service Commission, U-7930 rehearing.
- Michigan Public Service Commission, U-7930.

Case No. U-17767
Exhibit EM-2 (AJZ-2)


## Split of Uncollectibles to Power Supply & Distribution

### DTE Proposed Rate Design with Uncollectibles as Proposed by DTE

| | (A) | (B) | (C) | (D) | (E) | (F) | (G) |
|---|---|---|---|---|---|---|---|
| Line No. | | Total | Residential | Commercial | Primary | Other | Source |
| 1 | **Proposed by DTE:** | | | | | | |
| 2 | Distribution rev | $1,717,392 | $1,070,917 | $424,827 | $173,204 | $48,444 | Exh. A-14, F2, page 4, col (e) |
| 3 | Power Supply rev | 3,166,789 | 1,328,726 | 737,208 | 1,089,250 | 11,605 | Exh. A-14, F2, page 3, col (e) |
| 4 | Total revenues | 4,884,181 | 2,399,643 | 1,162,035 | 1,262,454 | 60,049 | = line(2) + line(3) |
| 5 | | | | | | | |
| 6 | Uncollectibles in DTE Dist rev | 52,799 | 40312 | 7925 | 4524 | 38 | Exh. A-13, F-1.5, line 3 |
| 7 | | | | | | | |
| 8 | **Rev w / o uncollectibles** | | | | | | |
| 9 | Distribution rev | 1,664,593 | 1,030,605 | 416,902 | 168,680 | 48,406 | = line(2) - line(6) |
| 10 | Power Supply rev | 3,166,789 | 1,328,726 | 737,208 | 1,089,250 | 11,605 | = line(3) |
| 11 | Total revenues | 4,831,382 | 2,359,331 | 1,154,110 | 1,257,930 | 60,011 | = line(9) + line(10) |
| 12 | | | | | | | |
| 13 | Distr rev w/o uncollect % | | 43.6821% | 36.1232% | 13.4093% | 80.6619% | = line(9) / line(11) |
| 14 | Pow Sup rev w/o uncollect % | | 56.3179% | 63.8768% | 86.5907% | 19.3381% | = 1 - line(13) |
| 15 | | | | | | | |
| 16 | **Split DTE uncollectibles:** | | | | | | |
| 17 | for Distr rate | $21,109 | $17,609 | $2,863 | $607 | $31 | = line(6) * line(13) |
| 18 | for Pow Sup rate | 31,690 | 22,703 | 5,062 | 3,917 | 7 | = line(6) - line(17) |
| 19 | Total uncollectibles | 52,799 | 40,312 | 7,925 | 4,524 | 38 | = line(17) + line(18) |
| 20 | | | | | | | |
| 21 | **Revised: w / Distr & P-S Split:** | | | | | | |
| 22 | Distribution rev | $1,685,702 | $1,048,214 | $419,765 | $169,287 | $48,437 | = line(9) + line (17) |
| 23 | Power Suppy rev | 3,198,479 | 1,351,429 | 742,270 | 1,093,167 | 11,612 | = line(10) + line(18) |
| 24 | Total revenues | 4,884,181 | 2,399,643 | 1,162,035 | 1,262,454 | 60,049 | = line(22) + line(23) |
| 25 | | | | | | | |
| 26 | *Checks: line(4)=line(24); line(6)=line(19)* | | | | | | |

Case No. U-17767
Exhibit EM-3 (AJZ-3)
Page 1 of 1

## Split of Uncollectibles
## to Power Supply & Distribution

### DTE Proposed Rate Design
### with No Change in Allocation of Uncollectibles

| Line No. | (A) | (B) Total | (C) Residential | (D) Commercial | (E) Primary | (F) Other | (G) Source |
|---|---|---|---|---|---|---|---|
| 1 | **Proposed by DTE:** | | | | | | |
| 2 | Distribution rev | $1,717,392 | $1,070,917 | $424,827 | $173,204 | $48,444 | Exh. A-14, F2, page 4, col (e) |
| 3 | Power Supply rev | 3,166,789 | 1,328,726 | 737,208 | 1,089,250 | 11,605 | Exh. A-14, F2, page 3, col (e) |
| 4 | Total revenues | 4,884,181 | 2,399,643 | 1,162,035 | 1,262,454 | 60,049 | = line(2) + line(3) |
| 5 | | | | | | | |
| 6 | Uncollectibles in DTE Dist rev | 52,799 | 40312 | 7925 | 4524 | 38 | Exh. A-13, F-1.5, line 3 |
| 7 | | | | | | | |
| 8 | **Rev w/o uncollectibles** | | | | | | |
| 9 | Distribution rev | 1,664,593 | 1,030,605 | 416,902 | 168,680 | 48,406 | = line(2) - line(6) |
| 10 | Power Supply rev | 3,166,789 | 1,328,726 | 737,208 | 1,089,250 | 11,605 | = line(3) |
| 11 | Total revenues | 4,831,382 | 2,359,331 | 1,154,110 | 1,257,930 | 60,011 | = line(9) + line(10) |
| 12 | | | | | | | |
| 13 | Distr rev w/o uncollect % | | 43.6821% | 36.1232% | 13.4093% | 80.6619% | = line(9) / line(11) |
| 14 | Pow Sup rev w/o uncollect % | | 56.3179% | 63.8768% | 86.5907% | 19.3381% | = 1 - line(13) |
| 15 | | | | | | | |
| 16 | **Split DTE uncollectibles:** | | | | | | |
| 17 | for Distr rate | *$21,109* | $17,609 | $2,863 | $607 | $31 | = line(6) * line(13) |
| 18 | for Pow Sup rate | *31,690* | 22,703 | 5,062 | 3,917 | 7 | = line(6) - line(17) |
| 19 | Total uncollectibles | *52,799* | 40,312 | 7,925 | 4,524 | 38 | = line(17) + line(18) |
| 20 | | | | | | | |
| 21 | *Weighted avg split Dist %* | *39.9803%* | | | | | = line(17) col(B) / line(19) col(B) |
| 22 | *Weighted avg split Pow Sup %* | *60.0197%* | | | | | = 1 - line(21) |
| ***23*** | ***Approved uncollectibles*** | ***$52,799*** | ***$40,312*** | ***$7,925*** | ***$4,524*** | ***$38*** | ***Revise to uncollectibles allocation*** |
| 24 | | | | | | | ***approved by MPSC in final order*** |
| 25 | **Split approved uncollectibles:** | | | | | | |
| 26 | for Distr rate | $21,109 | $16,117 | $3,168 | $1,809 | $15 | = line(23) * line(21) col(B) |
| 27 | for Pow Sup rate | 31,690 | $24,195 | $4,757 | $2,715 | $23 | = line(23) - line(26) |
| 28 | Total uncollectibles | 52,799 | 40,312 | 7,925 | 4,524 | 38 | |
| 29 | | | | | | | |
| 30 | **Revised: w/Distr & P-S Split:** | | | | | | |
| 31 | Distribution rev | $1,685,702 | $1,046,722 | $420,070 | $170,489 | $48,421 | = line(9) + line (26) |
| 32 | Power Suppy rev | 3,198,479 | 1,352,921 | 741,965 | 1,091,965 | 11,628 | = line(10) + line(27) |
| 33 | Total revenues | 4,884,181 | 2,399,643 | 1,162,035 | 1,262,454 | 60,049 | = line(31) + line(32) |
| 34 | | | | | | | |
| 35 | *Checks: line(4)=line(33); line(23)=line(28)* | | | | | | |

**Comparison of Capacity Prices**
**MISO Actual vs. DTE**

**$ per kW-year**

| Line No. | (A) | (B) 2014 | (C) 2015 | (D) 2016 | (E) 2016 | (F) 2018 | (G) 2019 | (H) 2020 | (I) 2021 | (J) 2022 | (K) 2023 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | **MISO Planning Reserve Auction Actual** | **$6.11** | **$1.27** | **?.??** | | | | | | | |
| 2 | | | | | | | | | | | |
| 3 | DTE U-17680 2015 PSCR Plan | $6.11 | $27.00 | $27.00 | $41.67 | $47.22 | $56.90 | | | | |
| 4 | Exh A-12, p.1, col (h) | | | | | | | | | | |
| 5 | | | | | | | | | | | |
| 6 | DTE 2015 replacement contract | | $25.00 | | | | | | | | |
| 7 | (U-17767 Dimitry direct testimony, | | | | | | | | | | |
| 8 | p.15, L25) | | | | | | | | | | |
| 9 | | | | | | | | | | | |
| 10 | U-17767, Exh A-21,Sched M1, L3 | | $6.0 | $15.7 | $18.6 | $21.5 | $25.2 | $29.8 | $37.1 | $69.7 | $82.3 |
| 11 | | | | | | | | | | | |
| 12 | U-17767, Exh A-21, Sched M2, L3 | | $18.9 | $27.0 | $41.7 | $47.2 | $56.9 | $59.3 | $64.9 | $75.2 | $80.3 |

**STATE OF MICHIGAN**

**BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION**

*** * * * ***

| | | |
|---|---|---|
| In the matter of the application of<br>DTE ELECTRIC COMPANY<br>for authority to increase its rates, amend<br>its rate schedules and rules governing<br>the distribution and supply of electric<br>energy, and for miscellaneous accounting<br>authority. | )<br>)<br>)<br>)<br>)<br>)<br>)<br>) | **Case No. U-17767** |

**PROOF OF SERVICE**

STATE OF MICHIGAN )
) ss.
COUNTY OF KENT )

Barbara Allen, the undersigned, being first duly sworn, deposes and says that she is a Legal Secretary at Varnum LLP and that on the 22nd day of May, 2015, she served a copy of the Direct Testimony, Qualifications and Exhibits of Alexander J. Zakem on behalf of Energy Michigan, Inc. in the above-referenced case upon those individuals listed on the attached Service List via email at their last known addresses.

Barbara Allen
Digitally signed by Barbara Allen
DN: cn=Barbara Allen, o=Varnum, ou, email=baallen@varnumlaw.com, c=US
Date: 2015.05.22 14:23:30 -04'00'

Barbara Allen

**SERVICE LIST**
**MPSC CASE NO. U-17767**

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