VARNUM
ATTORNEYS AT LAW

201 North Washington Square • Suite 910
Lansing, Michigan 48933
Telephone 517 / 482-6237 • Fax 517 / 482-6937 • www.varnumlaw.com

Timothy J. Lundgren tjlundgren@varnumlaw.com

July 21, 2017

Ms. Kavita Kale
Executive Secretary
Michigan Public Service Commission
7109 W. Saginaw Highway
P.O. Box 30221
Lansing, Michigan 48909

Re: MPSC Case No. U-18248

Dear Ms. Kale:

Attached for electronic filing in the above-referenced matter, please find the Direct Testimonies and Exhibits of Alex J. Zakem, Ralph C. Smith and Rupert R. ("Rob") Jennings and Direct Testimony of Lael E. Campbell on behalf of Energy Michigan Inc., as well as the Proof of Service. Thank you for your assistance in this matter.

Sincerely yours,

VARNUM

Timothy Lundgren

Digitally signed by Timothy Lundgren
DN: cn=Timothy Lundgren, o=Varnum, ou, email=tjlundgren@varnumlaw.com, c=US
Date: 2017.07.21 16:03:38 -04'00'

Timothy J. Lundgren

TJL/kc
Enclosures
c. ALJ
All parties of record.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

****

In the matter, on the Commission's own motion,	)	
to open a docket to implement the provisions of	)	
Section 6w of 2016 PA 341for	)	**Case No. U-18248**
DTE ELECTRIC COMPANY'S	)	
service territory.	)	
______________________________________	)	

DIRECT TESTIMONY & EXHIBITS OF

ALEXANDER J. ZAKEM

ON BEHALF OF

ENERGY MICHIGAN, INC.

ALEXANDER J. ZAKEM
DIRECT TESTIMONY

Table of Contents

I. **PURPOSE AND SCOPE** 4

II. **FACTUAL FOUNDATION OF PRESENT RELIABILITY** 5

A. **The MISO Reliability Construct** 5

B. **Satisfying MISO Capacity Obligations** 13

III. **BOUNDARY CONDITIONS TO CONSIDER** 18

IV. **FAULTS OF DTE ELECTRIC'S FILING** 23

V. **PRINCIPLES AND CRITERIA FOR A WORKABLE SOLUTION** 35

VI. **ENERGY MICHIGAN'S PROPOSED SRM SOLUTION** 37

VII. **BENEFITS OF ENERGY MICHIGAN'S PROPOSAL** 55

VIII. **EXAMPLE OF SRM CAPACITY CHARGE** 62

IX. **ADDITIONAL ISSUES** 63

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 joining Quest, I was employed by Detroit Edison from 1977 to 2001, where 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 provided 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 ("FERC"). Case citations are provided 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) Collective Reliability
- Exhibit EM-3 (AJZ-3) Example Cost Sharing
- Exhibit EM-4 (AJZ-4) Excerpts from 2017 OMS MISO Survey
- Exhibit EM-5 (AJZ-5) Cost Sharing Calculations
- Exhibit EM-6 (AJZ-6) DTE Exhibit A-4, Case No. U-18143

Q. What is the purpose of your testimony?

A. On behalf of Energy Michigan, I am proposing and explaining a solution for implementing a state reliability mechanism ("SRM") as described in Section 6w of 2016 PA 341, considering also the provisions of the Commission's orders in Case Nos. U-18239 *et al.* and U-18197 *et al.* I will also be addressing specific, additional issues regarding DTE Electric's ("DTE" or "Company") various recommendations of several aspects of the SRM.

Implementation of the SRM can be complex, as I will explain later. Our proposed solution to implementing the SRM operates under present – not past – reliability procedures and "boundary conditions" of constraints that have to be considered, which I will explain first. Consequently, for ease of explanation, my testimony is separated into the following sections:

I. Purpose and Scope
II. Factual Foundation of Present Reliability
III. Boundary Conditions to Consider
IV. Faults of DTE's Filing
V. Principles and Criteria for a Workable Solution
VI. Energy Michigan's Proposed SRM Solution
VII. Benefits of Energy Michigan's Proposal
VIII. Example of SRM Capacity Charge
IX. Additional Issues

ALEXANDER J. ZAKEM
DIRECT TESTIMONY

I. PURPOSE AND SCOPE

Q. What are you proposing in your testimony for an SRM solution?

A. On behalf of Energy Michigan, I will propose and explain a solution for implementing the SRM called for in Section 6w of 2016 PA 341, considering the provisions of the Commission's orders in Case Nos. U-18239 *et al.* and U-18197 *et al.*, considering also reasonable application of current reliability procedures of the Midcontinent Independent System Operator ("MISO"), and considering other Michigan statutes and Commission orders that may affect various choices in implementing the SRM.

Q. Will you be offering a legal interpretation of PA 341 or of other relevant Michigan statutes?

A. No, not at all. I am not a lawyer, and am not offering legal interpretations. Nevertheless, the SRM is called for in a new statute, and it is necessary to cite that statute, as did DTE in its Application and testimony, in order to ensure that Energy Michigan's proposal is responsive to it. So I will recognize and explain the practical effect of implementation choices presented to the Commission under Section 6w and other Michigan statutes that affect the setting of electric rates.

Q. What aspects of implementing Section 6w are you addressing?

A. The SRM is complex because so many aspects are interrelated. Attempts to address them one at a time can prove unworkably complicated or unduly harmful to various parties. So instead, I am proposing a total solution to implementation, covering the four main aspects of Section 6w:

1. local capacity obligation;
2. demonstration of capacity;
3. pricing of the SRM capacity charge; and
4. four year ahead look.

Once these four main aspects of SRM implementation are solved, many of the minor or ancillary questions, such as due dates, customer switching, and duration of SRM charge, either go away or have simple solutions.

II. FACTUAL FOUNDATION OF PRESENT RELIABILITY

A. <u>The MISO Reliability Construct</u>

Q. What is MISO's current process for reliability?

A. The concepts in MISO's current process for reliability are often susceptible to interpretation as casual language, rather than as precisely defined procedural and operational concepts. The following information is being offered to make communications more efficient and more accurate by ensuring a common understanding of key terms and concepts.

Since the beginning of the MISO Market on April 1, 2005, MISO's basic principle of market operation and reliability has been referred to as "collective reliability." Collective reliability is embodied in two main principles:

a. *MISO uses all resources to serve all load*.

b. *MISO buys all energy and capacity and sells all energy and capacity*.

This began with energy at the start of the MISO Midwest Market in April of 2005, and then expanded to capacity when capacity requirements were instituted. According to the MISO Independent Market Monitor,

> MISO launched its markets for energy and financial transmission rights (FTRs) in 2005, its ancillary services market in 2009, and its most recent capacity market in 2013. These markets coordinate the planning, commitment, and dispatch of generation to ensure that resources are meeting system demand reliably and at the lowest cost. [1]

Q. Don't individual Load Serving Entities ("LSEs") use their own capacity and energy resources to serve their own customers?

A. No, they do not. That concept has been obsolete since 2005. We are in the 13th year of "collective reliability," where the pool of all resources serves the pool of all load. Exhibit EM-2 (AJZ-2) illustrates this concept. It would be a mischaracterization of present MISO operations for an LSE to claim that "our generation serves our load."

Using all resources to serve all load is more efficient, cheaper, and provides more reliability with fewer resources than the old way where each LSE required separate resources to serve the LSE's separate load.

[1] "2016 State of the Market Report for the MISO Electricity Markets," prepared by Potomac Economics, Independent Market Monitor for MISO, June 2017, p. vi. https://www.misoenergy.org/Library/Repository/Report/IMM/2016%20State%20of%20the%20Market%20Report.pdf

Q. What are the implications of collective reliability – that MISO uses all resources to serve all load?

A. There are several implications that will be important in designing a solution for implementing the SRM:

1. Which LSE owns which resources where <u>does not affect reliability</u>.
2. Customer switching <u>does not affect reliability</u>.
3. "Our resources serve our load" has been <u>obsolete since 2005</u>.
4. All customers in MISO receive the <u>same</u> reliability, provided there are no binding transmission constraints; and all customers in a zone (regardless of who their LSE is) receive the same reliability regardless of whether or not there are binding transmission constraints.
5. Excess capacity in one zone does not increase the reliability within the zone, but rather supplies other zones.

Q. The MISO tariff requires a showing of capacity. What is MISO's definition of capacity?

A. MISO's definition is – "***Capacity:*** *The instantaneous rate at which Energy can be delivered, received or transferred, including Energy associated with Operating Reserve, Up Ramp Capability, and Down Ramp capability, measured in MW.*" [MISO Tariff, Module A]

Q. What is capacity, in plain language?

A. Capacity is the *rate* at which energy can be converted from one form to another, ending with electricity, such as from coal to heat to mechanical energy to electricity. The rate at which energy is converted is called *power*, and electric power is expressed in Watts. A megawatt (MW) is one million Watts.

Q. How is capacity different from energy?

A. Capacity is not the energy itself, but a measure of the *ability* to convert the energy into electricity. Casually, we may use the terms "power" and "energy" interchangeably, but they are different things.

Q. Is capacity the same as the physical generation facility?

A Capacity is an *attribute* of a physical generation facility, but it is not the same as the facility itself. An analogy would be to the horsepower of an automobile engine – horsepower is an *attribute* of the engine, not the engine itself.

Q. What is MISO's definition of a Zonal Resource Credit ("ZRC"")?

A. MISO's definition is – "***Zonal Resource Credit (ZRC):*** *A MW unit of Planning Resource which has been converted from a MW of Unforced Capacity to a credit in the MECT, which is eligible to be offered by a Market Participant into the PRA, to be sold bilaterally, and /or to be submitted through a Fixed Resource Adequacy Plan.*" MISO Tariff, Module A.

Q. In plain language, what is a ZRC?

A. A ZRC represents one megaWatt of “unforced” capacity that has been qualified, tested, and quantified according to MISO rules under the MISO tariff, and then dedicated to MISO’s use for one Planning Year. MISO’s quantification includes a discount for historical random outages (“forced” outages), so ZRC capacity is specified as “unforced capacity,” or UCAP.

Q. Is a ZRC identified with a specific facility?

A. Yes. It is the facility itself, called a Planning Resource, that is qualified, tested, and quantified for the amount of capacity – number of ZRCs – that MISO will grant it. The *owner* of a Planning Resource has the ability to designate all or some of the resource’s qualified capacity as ZRCs.

Q. When a ZRC is sold or bought, what actually is the product being sold or bought?

A. The product consists of *financial rights* in the MISO resource adequacy construct. The purchase of a ZRC means:

a. The buyer has the *right to designate the prices* at which the ZRC will be offered in to the MISO Planning Resource Auction (“PRA”) for the Planning Year for which the ZRC qualifies.

b. The buyer has the *right to receive the Auction Clearing Price* (“ACP”) from the MISO PRA, provided the ZRC clears in the auction.

c. The buyer has the *right to re-sell* the ZRC to another market participant in MISO.

d. The buyer has the *right to include the ZRC in a Fixed Resource Adequacy Plan ("FRAP")*, subject to additional rules and procedures of MISO, in lieu of offering the ZRC into the MISO auction.

Q. Is the buyer of a ZRC responsible for the physical performance of the underlying facility?

A. No. That responsibility remains with the owner of the facility that created the ZRC. The purchase of a ZRC does not give a buyer a share of ownership or control over the operation of a generating resource.

Q. You have said that MISO buys all capacity and sells all capacity. What are the implications?

A. MISO buys all and sells all, with one exception that I will explain later. The implications for designing a solution for implementing the SRM are:

1. Satisfaction of MISO's capacity requirement is done with money, not with ZRCs (with one exception to be explained later).
2. A LSE pays to MISO the MISO Auction Clearing Price ("ACP") for the LSE's Planning Reserve Margin Requirement ("PRMR"), which is based on the LSE's forecast peak MWs.
3. The owner of a ZRC will receive the ACP if the ZRC "clears" – meaning is selected on the basis of lowest cost – in the MISO auction.

4. Thus, an LSE who owns ZRCs can financially offset the cost of satisfying its capacity obligations to MISO, because it will:
   - pay the ACP for each MW of PRMR, and
   - receive the ACP for each MW of ZRC.

Thus, even if and when an LSE owns a ZRC, the LSE satisfies its MISO obligations with money – paying the ACP – not with ownership of that ZRC. Paying the ACP for load and receiving the ACP for ZRCs is a two-way transaction. Since the owner of a ZRC has the right to specify the price of the ZRC offered into the MISO auction, it is possible that the ZRC will not "clear," in which situation the LSE still has to pay MISO the ACP but will receive nothing for its ZRCs.

Q. What is the MISO "Local Clearing Requirement"?

A. MISO determines a Local Clearing Requirement ("LCR") for each zone. Transmission of energy into a zone is limited by the capabilities of the transmission equipment. Considering the load in the zone and the characteristics of the portfolio of existing resources in the zone, the LCR represents the number of ZRC MWs that must be located within a zone in order that the internal zonal resources plus imports over transmission lines will be sufficient to maintain the MISO reliability standard of no more than 24 "loss of load" hours in 10 years.

MISO defines LCR as:

> ***Local Clearing Requirement (LCR):*** The minimum amount of Unforced Capacity that is physically located within an LRZ that is required to meet the LOLE while fully using the Capacity Import Limit for such LRZ. [Module A, Section 36.0.0, Definitions L.]

PA 341 defines LCR as:

> "Local Clearing Requirement" means the amount of capacity resources required to be in the local resource zone in which the electric provider's demand is served to ensure reliability in that zone as determined by the appropriate independent system operator for the local resource zone in which the electric provider's demand is served and by the commission under subsection (8)." [MCL 460.6w(12)(d).]

Q. Is not the MISO reliability standard cited as "one day in 10 years"?

A. That citation is jargon, a handy expression if one knows what it means. A loss of load hour means that there are insufficient generation resources to serve firm load in that hour. MISO determines the LCR through a statistical modeling process. Given that a loss of load event may last more than one hour – perhaps 3-6 hours during the peak hours of a day – the MISO standard means that the statistically expected loss of load events may be on the order of 4 to 8 days in a 10-year period.

So the oft-cited "one day in 10 years" does not mean one loss of load event in 10 years, but rather statistically 24 loss of load hours in 10 years (10 years comprises 87,600 hours).

B. <u>**Satisfying MISO Capacity Obligations**</u>

Q. How can an LSE satisfy its capacity obligations to MISO?

A. An LSE's capacity obligation to MISO is called its "Planning Resource Margin Requirement ("PRMR"). The PRMR is a MW number that includes the LSE's forecast peak at the time of the MISO peak, distribution losses, transmission losses, and a Planning Reserve Margin ("PRM") percentage. To satisfy its PRMR, an LSE must provide MISO with either or a combination of:

(a) money, or

(b) ZRCs

Using money and/or ZRCs, there are four ways for an LSE to meet its PRMR obligations, in the MISO tariff:

"LSEs will meet their PRMR by:

(i) submitting a Fixed Resource Adequacy Plan;

(ii) Self-Scheduling ZRCs;

(iii) purchasing ZRCs through the Planning Resource Auction process; and/or

(iv) paying the Capacity Deficiency Charge."

MISO Tariff, Module E-1, section 69A.

"All LSEs will <u>be required to meet their PRMR through the PRA process, unless they have opted out of the PRA pursuant to Section 69A.9</u> [FRAP] *and/or have*

decided to pay the Capacity Deficiency Charge. LSEs can Self-Schedule ZRCs to meet their PRMR, consistent with the Self-Scheduling Option in Section 69A.7.8." MISO Tariff, Module E-1, section 69A.7.1.b.

Thus, there are three ways the LSE can use money to satisfy its PRMR – (ii), (iii), and (iv) above – and one way it can use ZRCs, (i) above.

Q. Has DTE explained how it would provide capacity to meet the capacity obligation of the portion of an AES load that is covered by the SRM charge, as specified in Section 6w(7)?

A. No, it has not explained. As will be explained in Part III of my testimony, the utility cannot reassign a forecast PRMR from one LSE to another, nor can MISO reassign a PRMR obligation from one LSE to another. Consequently, under an SRM charge where the utility would receive the SRM payment, and given that the AES would still be responsible to MISO for capacity, there are only two possible procedures: (1) The utility gives the AES money so that the AES can pay its capacity bill to MISO, which is based on the ACP; or (2) the utility gives the AES sufficient ZRCs to submit to MISO and be paid the ACP and thus compensates the AES for paying its capacity bill. Both of these procedures appear to raise legal issues and will be addressed by Energy Michigan in its brief.

Q. What is a Fixed Resource Adequacy Plan, known as a "FRAP"?

A. A FRAP is the exception to paying money that I have mentioned previously. A FRAP is the exclusion of an amount of PRMR and a commensurate amount of ZRCs from the auction process.

The FRAP concept came about because certain types of LSEs – primarily municipalities – were not allowed by their city charters to take market-price risk. Even though selling a ZRC to the auction at the Auction Clearing Price and paying the same ACP to cover the PRMR load results in zero net costs, under some accounting rules the municipals considered that as putting assets at market price risk. Consequently, MISO developed a procedure, the FRAP, that technically kept the assets and the payments outside of the auction pricing process.

It is important to note that the resources and the load of the LSE submitting a FRAP are still accounted for in the auction process because MISO has to account for all load and all resources. It is also important to note that in actual operation, MISO uses all resources to serve all load, and that includes resources and loads submitted in FRAPs.

Q. What does "Self-Scheduling ZRCs" mean?

A. Self-Scheduling is the practice of submitting ZRCs into the auction at zero price. This ensures that the ZRCs will clear, and so the LSE is certain to receive the ACP. Since MISO also bills the LSE the ACP for its PRMR obligation, the <u>result is that the LSE receives the ACP for its ZRCs and pays the ACP for its PRMR capacity obligations</u>, and the net result is that the revenue from the ZRCs covers the same amount of PRMR obligation.

Q. What does "purchasing ZRCs through the Planning Resource Auction process" mean? Does an LSE actually buy a ZRC in the auction?

A. "Purchasing in the auction" means simply that the LSE pays MISO the ACP, and MISO pays out the ACP to owners of ZRCs who have submitted ZRCs into the auction. An LSE does not take title to ZRCs in the auction, nor are specific ZRCs assigned to a specific LSE in the auction. *MISO uses all resources to serve all load.* "Purchasing in the auction" is a term of art that means paying the ACP to MISO – in effect paying a share of the total cost of all the ZRC-qualified capacity that MISO acquires in the auction to cover the total projected load.

Q. What is the Capacity Deficiency Charge?

A. The Capacity Deficiency Charge is 2.748 times the Cost of New Entry ("CONE"). CONE is the highest price that the Auction Clearing Price can be. If an LSE refuses to participate in the auction, fails to submit a FRAP, and fails to self-schedule, then it is assessed the Capacity Deficiency Charge as a penalty. It makes no business sense for an LSE to go down this path, but there has to be some action in the MISO tariff to cover the situation of refusal to participate.

Q. Is the cost of or value of "capacity" or of a "capacity related" resource the same as the "fixed costs" of that resource?

A. No. "Fixed costs" is an accounting label for the expenses of a facility that do not vary with the output of the facility. Capacity is a speed rating, an attribute of the facility, not the facility itself. As far as satisfying MISO's capacity requirements, 1 MW of a qualified ZRC from a nuclear unit is the same as 1 MW of a qualified ZRC from a combustion turbine, although the fixed costs of the nuclear unit may be much higher than the fixed costs of a combustion turbine.

In this context, it is useful to remember that MISO's resource adequacy construct requires the existence of a certain number of ZRCs to ensure resource adequacy, but does not require any particular kind or type of facility. Thus, a facility's accounting fixed costs of the facility are not the costs of the resource adequacy benefits that facility may provide. Section 6w(3)(A) of PA 341 specifies "capacity-related generation costs" be included in the SRM charge, not "fixed costs." However, Section 6w does not define "capacity" or "capacity-related."

Q. How well does Section 6w of PA 341 accord with MISO's current procedures governing supply/demand reliability?

A. My assessment of Section 6w is that its wording does not always indicate an understanding of <u>current</u> MISO reliability procedures. It assumes that a LSE's capacity obligation to MISO is satisfied by ownership of physical capacity or capacity rights, when in fact such obligation is satisfied with money, as discussed above.

At the same time, Section 6w does specify meaningful standards that have to be observed. For example, it requires that an Alternative Electric Supplier ("AES") can demonstrate capacity through, "*owned or contractual rights to any resource that the appropriate independent system operator [i.e., MISO] allows to meet the capacity obligation of the electric provider*." Section 6w(6). And Section 6w does mandate that the demonstration of capacity be in accordance with the MISO tariff, stating that the resource requirements for demonstrating capacity, "*shall not be applied in any way that conflicts with a federal resource adequacy tariff*." Section 6w(6). Energy Michigan's proposal, therefore, must fit within these parameters.

III. BOUNDARY CONDITIONS TO CONSIDER

Q. What are "boundary conditions"?

A. A "boundary condition" is a label for a fact or event which must not be violated by a solution to a problem. For example, in the implementation of PA 341, a boundary condition would be that the MISO tariff remains unchanged. Consequently, a proposed solution to implementation, tested against the boundary condition, cannot ignore the current MISO tariff, and it cannot assume that the MISO tariff will be changed to accommodate the proposal.

Q. What are the boundary conditions to be considered in the implementation of Section 6w of PA 341?

A. Five main boundary conditions are relevant to any implementation of Section 6w:.

1. Michigan's cost of service statute, MCL 460.11(1), applies to rates set by the Commission.
2. A retail customer is not a MISO market participant or a MISO LSE.
3. DTE will have to procure additional capacity if it takes on the responsibility for satisfying additional PRMR of an AES under Section 6w.
4. Under the MISO tariff, an AES still has to pay MISO to satisfy its PRMR, even if DTE claims to take responsibility.
5. Under the MISO tariff, DTE Electric as a Local Distribution Company ("LDC") in MISO cannot reassign forecast load or PRMR from one LSE to another, including from an AES to DTE Electric.

Q. Would you explain each?

A. Yes, I will explain each briefly.

1. Michigan's cost of service statute, MCL 460.11(1), applies to rates set by the Commission. PA 341 is not the only law that applies to setting a capacity charge under Section 6w. Because the capacity charge becomes part of the rate structure for the utility, then MCL 460.11(1) also applies. How the Commission will harmonize Section 6w and MCL 460.11(1) is open to legal argument. Here, I will simply outline the principle provisions of MCL 460.11(1) that I believe will have a practical effect on the determinations to be made in this proceeding. MCL 460.11(1) states in part:

> Except as otherwise provided in this subsection, the commission shall ensure the establishment of electric <u>rates equal to the cost of providing service</u> to each customer class.
>
> In establishing cost of service rates, the commission shall ensure that each class, or sub-class, is assessed for its <u>fair share and equitable use</u> of the electric grid. [. . .]
>
> [. . .] The commission shall ensure that the cost of providing service to each customer class is based on the allocation of <u>production-related costs based on using the 75-0-25 method of cost allocation</u> and transmission costs based on using the 100% demand method of cost allocation. [. . .] *[MCL 460.11(1) emphasis added.]*

2. A retail customer is not a MISO market participant or a MISO LSE. A retail customer has no PRMR obligation to MISO. A retail customer cannot be charged for any service under the MISO wholesale tariff.

3. DTE states will have to procure additional capacity if they take on the responsibility for satisfying additional PRMR of an AES under Section 6w.

As DTE explained in its filed testimony, its plan in the short term is to buy <u>additional</u> needed capacity in the MISO auction. According to DTE, this could continue for three years until the utility can build or otherwise acquire new resources. If capacity is not available in the MISO auction, DTE intends to put AES load that pays the SRM charge on interruptible service, as testified to by DTE's witnesses:

> Q. Has DTE Electric made provisions to serve the future capacity needs of customers currently on Electric Choice (Choice)?

> A. No. Currently Alternative Electric Suppliers ("AES") serving Choice customers have the sole responsibility to provide the capacity necessary to serve those customers, therefore, the Company has not made arrangements to provide the required capacity to serve Choice customers. [Direct Testimony of Don M. Stanczak, p. 6, lines 20-25.]
>
> * * * * *
>
> If there is insufficient time for the Company to build, develop, or acquire sufficient capacity for Electric Choice customers returning <u>for the interim planning years of 2018, 2019, and 2020, the Company plans to participate in MISO's PRA for those planning years to attempt to meet the capacity obligation</u> of those Electric Choice customers. If MISO's PRA results in insufficient capacity, the Company will provide <u>interruptible service (as explained by Witness Stanczak) to serve the capacity obligation of those customers in the capacity queue</u>. [Direct Testimony of Angela P. Wojtowicz, p. 12, line 21 to p. 13, line 2. Emphasis added.]
>
> * * * * *
>
> As the Company builds, develops, or acquires sufficient capacity, customers temporarily on interruptible service will be returned to firm service. [Direct Testimony of Wojtowicz, p. 11, lines 23-25.]

4. Under the MISO tariff, an AES still has to pay MISO to satisfy its PRMR, regardless if DTE claims to take responsibility. Under the MISO tariff, all LSEs are obligated to satisfy their PRMR obligation by either paying MISO money or assigning ZRCs to a FRAP. <u>Without a change in its tariff</u>, MISO cannot choose to reassign forecast load from one LSE to another, such as reassigning responsibility from an AES to DTE Electric. MISO did propose a change in its tariff in its Competitive Retail Solution ("CRS") application which would have allowed such reassignment, but the FERC denied the application on February 2, 2017.

5. Under the MISO tariff, DTE Electric as an Electric Distribution Company ("EDC") in MISO cannot reassign forecast load or PRMR from one LSE to another, including from an AES to DTE Electric. The MISO tariff specifies the exact methodology that an EDC in a retail choice area, such as DTE, must follow in providing a load forecast for each of the LSEs in the EDC's distribution area. DTE determines the load forecast for each of the AESs in its distribution area following the methodology prescribed in the MISO tariff. Without a change in that MISO tariff, neither MISO nor DTE Electric as an EDC can choose to reassign responsibility to another party, such as reassigning responsibility from an AES to DTE. As noted above, MISO did propose such a change in its tariff in its CRS application filed with the Federal Energy Regulatory Commission on November 1, 2016, which would have allowed such reassignment, but the FERC denied the application on February 2, 2017.

Q. From assessing these boundary conditions, what are your conclusions?

A. I draw two conclusions:

First, two laws – not one – appear to govern setting the price of the SRM charge if the Commission considers applying the SRM charge as part of the retail electric rate. I believe that a practical application of MCL 460.6w under PA 341 versus the existing cost-of-service statute at MCL 460.11(1) would result in different rate outcomes, and consequently the two laws will somehow have to be harmonized by the Commission.

Further, an SRM charge to LSEs operating within the wholesale market, such as AESs, municipal electric utilities, and cooperatives, raises jurisdictional issues involving wholesale versus retail authority. I am not addressing the legal consequences of that in this testimony, nor opining as to the legality of one approach over another.

Second, <u>the SRM capacity charge should be forward looking, based on the costs that DTE Electric would actually incur</u> if providing capacity in return for receiving payment of the SRM charge. DTE states that it would have to <u>acquire additional capacity</u> from various possible sources. The cost of such acquisition is forward looking, not dependent on previous investments in existing resources that are not going to provide <u>additional</u> capacity. Thus, the focus should be on the costs of acquiring capacity, and not on DTE's fixed costs for existing facilities that provide capacity.

IV. FAULTS OF DTE ELECTRIC'S FILING

Q. DTE Electric has submitted a proposal for implementing Section 6w in its direct testimony. Are there faults in its proposal?

A. DTE is certainly knowledgeable about its historic costing methods and how the electric grid operates. Yet there are faults in the sense that certain of the boundary conditions are either not met or not addressed in DTE's proposals. The foundation of DTE's proposal is the assumption of a dire and impending shortage of capacity, without any evidence of substance, and the fear of such shortage drives several aspects of DTE's proposal. In addition, there are conclusions that do not appear to align with the requirements of Section 6w.

DTE's testimony does not fairly consider the cost-of-service statute in calculating its proposed SRM charge. DTE asserts the MPSC must define a local capacity obligation, but does not give a reason why. DTE asserts that there is no conflict between the MISO tariff and the MPSC's "role" in "setting and enforcing compliance" with MISO standards, yet offers no specific situation or example.

DTE's testimony continually warns that its proposal is designed for shortages of capacity, but offers only outdated and incorrect information regarding the possibility of such shortages.

DTE does not explain how it, as both an Electric Distribution Company and Load Serving Entity subject to the MISO tariff will be able to remove a MISO PRMR obligation for another LSE and transfer that obligation to itself, in apparent violation of MISO's tariff, which its proposal would require. Certain aspects of DTE's submittal, such as a 30-year obligation for paying historic embedded costs, 4-year notice of return to service, 30-year irrevocable selection of bundled or "capacity only" service, and a myriad of associated and other changes to its Retail Access Service Rider EC2, are excessively complicated, are contrary to just and reasonable ratemaking practices, and are unneeded under Energy Michigan's proposal.

Q. Please explain how you see the State's cost-of-service requirement relating to DTE's proposal.

A. DTE ignores cost-of-service principles and the requirements of the cost-of-service statute. Thus, while DTE states that it will have to acquire <u>additional</u> capacity to meet any capacity requirements that it must take on under Section 6w, it still seeks to determine the cost of such additional capacity from the costs of <u>historical investment</u> in facilities that would <u>not</u> be providing the capacity service. Under cost-of-service principles, the costs to be paid should be the costs imposed by those customers – that is, the cost of the <u>additional</u> capacity that DTE states it would have to acquire to cover the MISO capacity obligations for customers paying the SRM charge.

The cost of acquiring additional capacity will be quite visible. Whether buying from the market, purchasing through the MISO capacity auction, or building new resources, the cost will be incremental, not historical. DTE's proposal ascribes historical embedded costs of facilities that do not provide the additional capacity to the value of additional capacity being provided, and thus violates Michigan's established cost-of-service principles.

Q. Does not Section 6w require that the SRM charge be based on historical embedded costs?

A. Section 6w(3)(a) does specify the inclusion of "the <u>capacity-related</u> generation costs included in the utility's base rates, surcharges, and power supply cost recovery factors" (emphasis added). But, as explained previously, there is another clause in Michigan law that also specifies how electric rates are to be set – the cost-of-service statute cited previously. The Commission will have to sort out how to apply both of these laws at the same time in a reasonable way.

Section 6w does not include a definition of "capacity related." Nor does Section 6w include the term "fixed costs." Even if one were to believe that historical embedded costs should be used in the method of calculation, DTE mistakenly applies to Electric Choice customers the requirement that production costs be allocated according to the 75-0-25 method that is in the cost-of-service statute. Electric Choice customers do not take energy service from DTE, so the 25% of production costs should not be allocated to them based on energy. Without taking energy, Electric Choice customers do not contribute to the monthly peak demands during the summer months, so the 75% of production costs should not be allocated to them based on peak demand.

DTE fails to subtract "all energy market sales" net of fuel, as is stated in Section 6w(3)(B), instead subtracting market purchases from market sales and crediting only the small difference against capacity related costs.

Energy Michigan's witnesses Mr. Rupert R. Jennings and Mr. Ralph C. Smith are addressing cost-of-service issues in the determination of the SRM capacity charge for AES customers, under the situation that the SRM charge for additional capacity resources would be determined by traditional historical embedded cost of service for utility full-service customers, as DTE has proposed.

Based on the fact that DTE will be acquiring incremental capacity, my recommendation to the Commission is that the cost of “capacity-related generation costs” be the cost of the capacity-related costs of the incremental capacity that would have to be acquired if AES customers pay the SRM charge. This would be a reasonable way to set the SRM capacity charge and to ensure that DTE’s charge complies with the State's cost-of-service principles and law.

Q. How does DTE arrive at the conclusion that Section 6w requires an obligation to own or have contractual rights to capacity resources within the local MISO zone, which is Zone 7 in lower Michigan?

A. DTE merely asserts the conclusion, without any rationale or evidence:

> In order to ensure electric reliability within the lower peninsula of Michigan, a certain amount of capacity resources must be located within LRZ 7. As described earlier in my testimony, MISO establishes a LCR for each LRZ based on reliability standards.
>
> It is imperative that the MPSC define the capacity obligation set forth in Section 6w of 2016 PA 341 to be firm capacity resources within LRZ 7 to meet an LSE’s load ratio share of the LCR.
>
> The resource adequacy provisions of MISO’s tariff do not conflict with the MPSC’s role in setting and enforcing compliance with its standards for resource adequacy. [Direct Testimony of Wojtowicz, p. 14, line 19 to p. 15, line 1. Emphasis added.]

Q. Does the Commission have the authority or the responsibility to set and enforce compliance with MISO resource adequacy standards?

A. Whether a state commission has authority under Michigan law to set and enforce compliance with MISO's federally-approved tariff is a legal question, which Energy Michigan may address in its brief. If the Commission has no role, then obviously there can be no conflict – but then the Commission would not be able to set a local capacity obligation. If the Commission does have a role and the associated authority, then there may be a conflict depending on how it is implemented, because the MISO tariff specifies a local obligation only on a total zone and not on individual LSEs or customers within the zone. Either way, DTE's rationale for the Commission to set a local reliability obligation is merely to declare that "it is imperative" and that MISO's tariff does not conflict with the "MPSC role," although that role is not specified.

Q. Does Section 6w specifically impose a local capacity requirement?

A. I cannot see where it does. There simply is no wording imposing a local requirement in the demonstration of capacity and DTE does not cite any. In earlier versions of Senate Bill 437, there was a local requirement, but that was removed by the time the final version was passed as PA 341. Whether or not local capacity is required under Section 6w is a legal question that will be addressed in Energy Michigan's brief. Practically, there is nothing in the Section 6w that provides any information on how and to whom such a local requirement should be applied. Section 6w(8)(c) contains the wording " . . . the commission shall set <u>any required local clearing requirement</u> and planning reserve margin requirement, <u>consistent with federal reliability requirements</u>." From a practical perspective, what would the Commission do if there is no "required local clearing requirement"? It would seem that the construction here is circular.

Also, "any required local clearing requirement" must be set "consistent with federal reliability requirements," and as Ms. Wojtowicz has noted in her testimony, federal reliability requirements for LCR are established for the zone as a whole, not imposed on individual LSEs within a zone. Consequently, DTE's recommendation that the MPSC impose a local capacity obligation on LSEs within a zone is not consistent with MISO's tariff rules, which establish a Local Clearing Requirement for the zone as a whole. <u>Thus, DTE's proposal does not appear to be consistent with the requirements of Section 6w.</u>

Q. If the Commission were to set a local requirement on its own authority, what factors should the Commission consider?

A. MISO's LCR is set based on a calculation that overstates the need for local capacity. If a local requirement is set too high, it will result in capacity in the state being overbuilt, which has the potential to cost the citizens of Michigan a substantial amount of money. Energy Michigan's proposal will eliminate the need for any local requirement in addition to that specified in the MISO tariff, but if the Commission were to set a local requirement on its own, my recommendation would be to not set such a requirement until MISO has fixed its LCR calculation.

The illustration of how the overstatement happens and the total quantification are straightforward. MISO's calculation of the LCR can be expressed as:

(Eq. 1) LCR = LRR – CIL – non-pseudo tied exports

where LRR is the Local Reliability Requirement and CIL is the Capacity Import Limit, and non-pseudo tied exports are zero for Zone 7.

LRR is the amount of resources that a zone would need if the zone had no import transmission capability at all. LRR is generally higher than the actual total of the PRMR of the LSEs in the zone, since the resources in the single zone are not as diversified as the resources in the MISO region. The subtraction of the CIL accounts for the fact that a zone is not isolated but rather can import a specified amount of power.

The values for the variables in Eq. 1 for Zone 7 are shown in MISO's report of the 2017-2018 Planning Resource Auction.[2] LRR is 24,429 MW, CIL is 3,320 MW, non-pseudo tied exports is 0 MW, and the resulting LCR is 21,109 MW:

(Eq. 2) LCR = 24,429 – 3,320 – 0 = 21,109 MW

Consider the situation where the CIL is as large as the PRMR – that is, Zone 7 could import all the capacity required for all the LSEs in the zone. Zone 7 PRMR is 22,295 MW.[3] Suppose the CIL is also 22,295 MW. Then the LCR is:

[2] MISO, "2017/2018 Planning Resource Auction Results," May 10, 2017, page 14, available at: https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/RASC/2017/20170510/20170510%20RASC%20Item%2002a%202017-18%20PRA%20Summary.pdf.

[3] MISO, "2017/2018 Planning Resource Auction Results," *op. cit*, page 14.

(Eq.3) LCR = 24,429 – 22,295 – 0 = 2,134 MW

Eq. 3 means that if Zone 7 could import all the capacity to meet all the PRMR in the zone, MISO's formula would still require an additional 2,134 MW within the zone. This makes absolutely no engineering sense. MISO's determination of LCR for zones is substantially overstated. [4]

Considering that Zone 7 has a Capacity Import Limit of 3,320 MW, not 22,295 MW, the practical overstatement of LCR for Zone 7 is about 300 MW, not the full 2,134 MW. An imposition of a local capacity obligation would result in 300 MW of excess capacity in the state, costing Michigan customers about $180 million (= $600/kW x 300 MW) of excess investment in new generation, with no benefit of increased reliability.

Q. Is there an impending shortage of capacity in the MISO region or in Zone 7 that would affect reliability?

A. According to the recent MISO/OMS survey and the recent Annual Capacity Auction for 2017-2018, there is ample capacity all across MISO and every zone has met its LCR. I discuss this also in Part VII of my testimony. MISO has been underreporting future capacity for 10 years. That is why in previous MISO reports, there was generally an image of a shortfall of capacity from a few to several years out, but when those years actually arrived, there was excess capacity. There is a large amount of capacity under

[4] The LCR calculation issue was addressed in the FERC docket ER13-2298. MISO stated it would take up the issue with stakeholders subsequently, but has not done so to date.

development in MISO. In the past, almost all of this capacity under development was excluded from survey results, but starting this year, a realistic portion of it is now included. As a result, there is <u>no longer a projected shortfall</u>. The latest <u>2017 MISO/OMS report shows reserve margins of about 20% through 2022.</u>

Page 2 of Exhibit EM-4 (AJZ-4) shows a page from the recent 2017 MISO/OMS study illustrating the projected ample reserve margins.[5] Page 3 of the exhibit shows the capacity under development in MISO, of which a small part was included in the supply demand tally that shows ample reserve margins. Page 4 of the exhibit shows the 2022 outlook, with 20.0% reserve margin for the region. This page also shows the breakdown by zone – Zone 7 shows a shortfall of between 1.5 and 1.1 GW (1,500 to 1,100 MW), which is well within the Capacity Import Limit into Zone 7 of 3,320 MW at present. Page 5 of the exhibit shows the capacity under development in Zone 7, of which a small part was included in the supply demand tally. Although some of the capacity under development in Zone 7 may likely not go into service eventually, the amount under development at present far outweighs the MISO's projected shortfall in 2022 for Zone 7. Further, more potential resources could be developed over time – the page shows only what MISO knows at the present time.

Q. Does DTE have projections relating to the supply/demand situation in Zone 7, and if so what do they show?

[5] https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/RASC/2017/20170712/20170712%20RASC%20Item%2002%20OMS%20Survey%20Results.pdf

A. Yes. In its 2017 PSCR Plan filing, DTE included price projections for energy and capacity through 2021. Exhibit EM-6 (AJZ-6) shows Exhibit A-4 from DTE's filing in that docket (U-18143). In its filing, DTE's projected capacity prices in the 2018-2021 period are:

2018	$24.39	kW-year	(equivalent to $67 per MW-day)
2019	$37.73	kW-year	(equivalent to $103 per MW-day)
2020	$52.31	kW-year	(equivalent to $138 per MW-day)
2022	$42.89	kW-year	(equivalent to $118 per MW-day).

These projected capacity prices are well under the MISO CONE value of approximately $260 per MW-day. These projected capacity prices therefore indicate that DTE is not anticipating any capacity shortages in Zone 7 at least through 2021.

DTE also projects stability in energy prices. See Exhibit EM-6. Its projected 24-hour price in 2018 averages $30.09 per MWh, and in 2021 averages $30.65 per MWh.

Q. What can be concluded from DTE's projected prices?

A. DTE expects flat energy prices and modest capacity prices in Zone 7 at least through 2021. DTE, however, has predicated the design of its proposed implementation of the SRM on the prospect of dealing with capacity shortages in that same time period, thereby imposing drastic charges on Electric Choice customers and discriminating between Electric Choice and full service customers regarding the provision of capacity service under the SRM. But DTE has offered no evidence that its argument of potential shortages of capacity has any practical chance of occurring, and in fact has offered evidence in its PSCR plan case that it does not really expect a capacity shortage to occur.

While one can always theorize that at some time in the future there could be capacity shortage, the projections from the 2017 OMS MISO study illustrate that such a situation is not likely to happen for decades, given the capacity currently under development and the potential for even more capacity to be developed. The Commission should not accept DTE's proposal, given all of the proposal's faults and the lack of a supporting rationale for its assumptions.

In contrast, Energy Michigan's proposal will maintain zonal reliability in Michigan, apportion fair costs to all, and will eliminate the need for many of the complex rules and procedures in DTE's proposal.

Q. Does DTE explain how it, as both an Electric Distribution Company and Load Serving Entity subject to the MISO tariff, will be able to remove a MISO PRMR obligation for another LSE and transfer such obligation to itself?

A. No, DTE does not explain. Rather, it only asserts it has the ability to do so, in the testimony of its witness:

> **Q. How would the resource adequacy requirements in the MISO Tariff be met by an AES if their customers are paying a capacity charge to the utility?**
>
> A. The MISO Tariff allows the Electric Distribution Company (EDC) to assign LSE obligations by appropriate portions of the total forecasted

> coincident peak demand. If AES customers are paying a capacity charge to the utility, the EDC, or utility, would comply with the MISO Tariff resource adequacy provisions by <u>allocating the appropriate forecasted coincident peak demand for those customers to its own forecasted coincident peak demand</u>. [Direct Testimony of Wojtowicz, p. 15, lines 3-10. Emphasis added.]

Q. Under the MISO tariff, for customers paying an SRM capacity charge, can DTE as an Electric Distribution Company decide to allocate the forecasted coincident peak demand of such customers to itself, DTE as an Load Serving Entity?

A. No, this would be contrary to the MISO tariff. The MISO tariff has specific rules governing exactly how an EDC must allocate the forecast for its area to the LSE in its area. An EDC cannot simply decide to switch forecasts from one LSE to another. As I have explained above, the MISO tariff would need to be changed for DTE to accomplish this, and such a proposed tariff change – the CRS – has already been denied by the FERC. Thus, DTE's proposal appears to be inconsistent with the MISO tariff.

V. PRINCIPLES AND CRITERIA FOR A WORKABLE SOLUTION

Q. Is the implementation of the SRM like a rate case?

A. It is quite different from a typical rate case. A rate case may have a large number of issues, but most of these issues are separate from each other and so are proposed, argued, and resolved separately. The SRM is different – it is a "mechanism" which, like a machine, should have all parts – the four main aspects listed above – working together. To assess how well the parts of an SRM solution work together, it is helpful to establish a set of principles or criteria by which to judge the merit of any proposed solution.

Q. What principles and criteria should the Commission use in assessing how to implement the SRM?

A. I am offering the principles and criteria that guided Energy Michigan's proposal herein. The solution should be:

a. ***Holistic and integrated*** – A single, unified proposal, not something where opponents pick and choose what they like or don't like, to their advantage.

b. ***Implementable*** – Straightforward, understandable and able to be applied in a uniform way; not requiring complex new systems or pages of special rules, special cases, or exemptions.

c. ***Recognize current and practical reliability goals*** – Work in concert with MISO's current tariff requirements, not create new rules that surpass MISO's requirements or are inconsistent with them.

d. ***Not harmful to any party*** – Implementation should not be a "zero sum game," where one party benefits at the expense of another. For example, if Solution A benefits party X but harms party Y, while Solution B benefits both parties, then Solution B should be the solution of choice.

e. ***Preserve Electric Choice*** – PA 341 preserves the Electric Choice market in Michigan. Electric competition is based on (i) continued access to reasonably market-priced electric products, (ii) continued freedom to contract innovatively with customers, and (iii) continued ability to assess and manage future risk. Proposals that price customers out of the market, interfere with customer contracts, and create unquantifiable future risks do not follow this principle.

f. ***Avoid "re-negotiation" of PA 341 under the guise of "implementation" –*** The legislative process behind SB 437/PA 341 was long, but the battle is over. Some things were removed in the final version of the Senate Bill, and some things were added in. On reviewing DTE Electric's filing, it appears that the Company wants to implement requirements that are not consistent with the <u>final</u> version of Section 6w found in PA 341.

Q. Is preserving or eliminating Electric Choice an issue in implementing the SRM?

A. Electric Choice has been in existence under Michigan law and Commission rules for 17 years. While its survival or demise ought not be a focus in implementing the SRM, my observation is that the survival of Electric Choice was a main factor in the legislative debate concerning the provisions in Section 6w of PA 341, and that it is still a significant factor in the contests over SRM implementation. Section 6w at times separates "electric utilities" from "alternative electric suppliers" ("AESs"), and these distinctions will have to be analyzed carefully in this proceeding. In the Staff technical conferences, I have heard utility representatives describe full-service customers as those who "did the right thing" and "played by the rules," implying that Electric Choice customers somehow did not. There ought not to be such a bias against Electric Choice when implementing Section 6w. SRM implementation should not present utilities with an opportunity to eliminate or constrain Electric Choice.

VI. ENERGY MICHIGAN'S PROPOSED SRM SOLUTION

Q. What are the elements of implementation of an SRM under Section 6w that a solution must address?

A. As noted previously, there are four main aspects to address in implementing the SRM under Section 6w:

1. Local capacity obligation.
2. Demonstration of capacity.
3. Pricing of the SRM capacity charge.
4. Four year ahead look.

Q. What is the current situation in local Zone 7, lower Michigan?

A. Several factors relevant to the current situation in Zone 7 are pertinent to potential solutions for SRM implementation:

- Zone 7 currently meets its LCR amply.
- Zone 7's future electric growth is virtually zero.
- Utilities have sufficient capacity for full-service customers but do not have excess capacity.
- Utilities intend to replace retiring capacity, for full-service customers only.

Q. What do you conclude from reviewing this situation?

A. My conclusions are:

- Zone 7 will continue to meet its LCR with <u>no additional capacity other than what is needed for replacement</u> of retiring resources.

- The normal utility planning process and current utility plans – which consider future retirements – are consequently sufficient to meet future LCR.
- Without a sharing of future costs under implementation of PA 341, full-service customers only would pay for replacement of retiring units.
- Since the LCR can be covered by normal utility capacity planning, the LCR issue reduces to a question of financial responsibility, not electric reliability.
- In prior stranded cost and securitization proceedings, Electric Choice customers paid approximately $550 million for utility resources that did not provide any services to Electric Choice customers but have provided capacity and energy for full-service customers.

Q. What does this imply for the implementation of Section 6w under PA 341?

A. The implications are:

- ***Forward Look:*** Maintaining LCR is a forward looking process because it depends on the acquisition of <u>new</u> resources to replace existing resources.
- ***Fairness:*** All customers in Zone 7 benefit from maintaining LCR.
- ***Equity:*** All customers in Zone 7 should contribute to the cost of maintaining future LCR in proportion to the benefits they receive.
- ***Practicality:*** Although zone-wide (nearly lower peninsula-wide) cost sharing may be theoretically optimal for sharing costs, in my opinion it would end up being excessively complex, contested, and difficult if not impossible to put into

place, especially in a timely manner. Implementing cost sharing of future resources on a utility by utility basis would be reasonable and workable, considering that the two large utilities in the state, Consumers Energy and DTE Electric, have visible capacity plans for the future.

Q. Would you summarize Energy Michigan's proposal for implementing the SRM?

A. The proposal is straightforward and based on the preceding principles and observations, as well as on the principles for a solution and the foundations of reliability explained earlier.

a. Because (i) the LCR is currently met, (ii) Michigan is a virtually no-electric-growth area, and (iii) utilities are planning to maintain their current level of resources, normal utility capacity plans will preserve zonal reliability. Therefore, zonal reliability becomes a financial issue, not a reliability one. DTE does not have to do anything different from continuing to replace retiring capacity as it has stated it plans to do in various filings to the Commission. Under Energy Michigan's proposal, the cost of the new replacement resources would be shared by all of the LSEs in the DTE distribution area, rather than borne only by DTE as under present Commission rules.

b. Once the zonal LCR issue is solved by (a) above, reliability will be maintained by MISO in accordance with its present tariffs, and as a result having the "demonstration of capacity" rules be in accordance with the MISO tariff will maintain reliability.

Q. What is Energy Michigan's proposal for implementing the SRM under Section 6w of PA 341?

A. Energy Michigan's proposal addresses the four critical aspects of implementation. It incorporates an equitable sharing of costs of replacement resources and provides rules for demonstration of capacity.

First, I will explain our proposal for equitable cost sharing for maintaining Local Capacity Requirements in the zone. This includes (a) a definition of what resources qualify for cost sharing, (b) the valuation of capacity that would be charged to LSEs, and (c) how the charge would be apportioned to LSEs. Second, I will describe how LSEs can demonstrate capacity, thereby preserving reliability after the LCR is met. Third, I will recommend an SRM capacity charge for those LSEs who do not demonstrate sufficient capacity. Fourth, I will address how the above three aspects should be implemented over a four-year outlook that Section 6w specifies.

Q. What resources would qualify for cost sharing?

A. The resources that would qualify for cost sharing are those that would count toward the maintenance of meeting the MISO zonal LCR – which was explained previously in my testimony) in Zone 7. This would include new resources built within Zone 7, including plant improvement projects that increase capacity, new demand resources, and new energy optimization resources. All new resources eligible for cost sharing must be qualified as ZRCs by MISO. In addition, with the exception of PURPA QFs that DTE is relying on for its capacity needs, the new resources must be approved by the Commission through the Certificate of Necessity process, which affords a review of the prudency and need for the resource.

Excluded would be the purchase of an existing resource or the output of an existing resource that is already functioning in Zone 7, because the purchase does not add any capacity to Zone 7, but rather is merely a change of ownership. Also excluded would be a new resource built outside of Zone 7 or the purchase of an existing resource or the output of an existing resource from outside of Zone 7. Obviously, any resource outside of Zone 7 by definition cannot satisfy the LCR for Zone 7.

Q. How would the value of capacity from the new resource be determined for the purpose of cost sharing?

A. The cost to be shared is the cost of the capacity of the new resource, not the total cost. The total cost may be much larger to gain benefits such as lower fuel costs, lower emissions, greater reliability, *etc*. MISO, with approval by the FERC, has determined that the cost of new capacity is represented by the Cost of New Entry ("CONE"). This is an annualized cost of a combustion turbine, without subtraction for sales of capacity, energy, or ancillary services. The cost is determined by zone in MISO, and MISO files an update with the FERC each year. Calculation of Cone is governed by the MISO Tariff, Module E-1, section 69A.8, At present, the CONE in Zone 7 is $94,900 per MW per year.[6]

[6] FERC Docket No. ER16-2662, filing September 23, 2016, Attachment B.

As described previously, MISO pays the Auction Clearing Price for each MW of ZRC to the owner of the ZRC. Consequently, if a utility builds a new resource, it will receive the ACP for the ZRC capability of the resource. The ACP may be well under the CONE, as it has been consistently for the last several years.

Energy Michigan's proposal is that fair compensation for the capacity value of the qualified new resource should be the CONE. Since the building utility will receive the ACP from MISO, Energy Michigan proposes that the cost to be shared among the LSEs in the utility distribution area be the difference between the ACP and the CONE, or the quantity CONE – ACP for each ZRC MW, per year. This is an annualized cost, and the CONE – ACP charge would begin when the resource is first placed in service and would continue for as long as the new resource is in service. For PURPA QFs, the compensation would be the greater of (a) the Commission-determined avoided cost of capacity that the utility is paying to the QF minus ACP or (b) zero and would continue for the length of the power purchase agreement.

Q. Would the applicable CONE and ACP prices change over time?

A. I recommend that the CONE remain fixed at the level it is at the time the resource is placed in service. CONE changes very little from year to year. A static CONE applied to the ZRC MWs of the new resource thus establishes a stable total capacity cost of the resource.

The ACP has varied widely from year to year. Since the recovery of the capacity cost is in two parts – ACP from MISO and CONE – ACP from the LSEs in the distribution area – recovery of total capacity costs under the proposal must recognize that MISO will be paying the utility a different amount each time the ACP changes, each Planning Year. So the ACP used in the cost sharing price CONE – ACP should also change each year as the MISO Zone 7 ACP changes.

Q. How would the CONE – ACP charge be apportioned to LSEs in the utility distribution area?

A. The apportionment would be pro-rata on the basis of relative PRMR. An "apples to apples" perspective is required. MISO discounts the MW output of the new resource by the historical – or estimated, for new units – forced outage rate to determine the ZRC rating on an unforced capacity, or "UCAP" basis. MISO also requires the PRMR to be satisfied on a UCAP basis. Therefore the proration should be on the basis of the relative PRMR of the LSEs in the distribution area, applied to the ZRC rating of the new resource. While this is complicated to say in words, part VIII of my testimony along with Exhibit EM-3 (AJZ-3) shows an example of the proration.

In the proration, an LSE other than the utility builder of the new resource will receive a subtractive credit for owned or contracted resources that already qualify for meeting the LCR. This aspect is also shown in the example.

Q. Why should not the utility builder receive a credit for owned or contracted resources that already qualify for meeting the LCR?

A. The proposal here is that the utility is building new resources to replace retiring resources, for the purpose of covering capacity requirements for its full-service customers. If the utility were to get a subtractive credit for existing resources, then it would not pay for any of the cost of the new resource, and consequently the entire ZRC value of the new resource would be apportioned to other LSEs. With a MW credit to other LSEs prorated on the ACP (which I will explain later), this would leave the utility in the position of not having sufficient replacement ZRCs. Thus, the utility would have to go through the build cycle again and again, each time with insufficient additional ZRCs, which would not make any sense.

Q. Realizing that you will have a more complete example later, can you give a short and simplified example of the pro-ration method?

A. Yes. Assume that the distribution area PRMR is 1,000 MW, with the utility PRMR at 900 MW and an AES PRMR at 100 MW. Assume that the zonal LCR is 95% of the total zone PRMR. or 950 MW. Then the utility share of the LCR is 900 x .95 = 855 MW, and the AES share of the LCR is 100 x .95 = 95 MW.

Assume that the utility builds a new unit of 50 MW to replace a retiring 50 MW unit. Then the utility will receive a pro-ration of 855/950 = .90 of the capacity cost of the new unit to be shared, and the AES will receive a pro-ration of 95/950 = .10 of the capacity cost of the new unit.

The annual "capacity cost of the new unit to be shared" is 50 MW x (CONE – ACP). Assume CONE is $90,000 and the ACP is $20,000. Then the cost of the new unit to be shared is 50 x ($90,000 – 20,000) = $3,500,000 per year. The utility would pay .90 of that, or $3,150,000, and the AES would pay the utility .10 of that, or $315,000 per year.

In short, if the AES represents 10% of the distribution area load, then it will pay 10% of the annual capacity cost of the new unit to be shared – *i.e.*, cost that is not covered by MISO paying the ACP. Thus, the utility builder is guaranteed to receive the MISO CONE for the capacity of the new resource.

Q. In this situation, what happens to the LCR for the zone?

A. For the zone, 50 MW are being retired, and 50 MW are being added. Thus, there is no change in the amount of resources that satisfy the LCR, and consequently no change in the reliability of Zone 7.

Q. Does the AES get any benefits from the energy or ancillary services from the new resource?

A. No. The AES pays only for its share of the capacity. The utility retains full rights to the energy and ancillary services value of the full 50 MW.

Q. Does the AES receive a capacity credit?

A. Yes, the AES would receive a percentage capacity credit based on the level of its CONE – ACP prorated contribution compared to full CONE.

In this example, (CONE – ACP)/CONE = 78%. Therefore the AES would receive a capacity credit of 50 MW x .10 x 78% = 3.9 ZRC MW.

Q. Why doesn't the AES receive a fixed capacity credit of 10% of the 50 MW, or 5 MW?

A. As the CP draws closer to CONE, the amount of money based on the ACP that the utility receives from MISO increases, and commensurately the amount based on CONE – ACP that the AES pays decreases. If the capacity credit were fixed, then the amount that the AES pays to the utility would not reflect the capacity value of the MWs credited – the capacity value received would be greater than the MW credit. So determining the capacity credit based on relative prices of CONE and ACP results in a proper credit.

Q. Why does the AES pay a share of the cost based on its 5 MW PRMR but receive a capacity credit of only 3.9 MW?

A. "Based on its 5 MW PRMR" is only part of determining the AES's share of cost. The other part is the level of the ACP.

The higher the ACP,

the more the utility receives from MISO,

the less the AES has to pay to reach CONE,

the less the ZRC MW credit.

All ends up fair for both utility and AES. Neither is harmed.

Q. This sounds complicated for a difference of a 1.1 MW credit. Is it workable?

A. It may seem complicated to explain in words, but the arithmetic is very short and simple in actual application: MW Credit = 50 MW x .10 x (CONE-ACP)/CONE.

That's all there is to it.

As noted earlier, the principles of Energy Michigan's proposed solution are that it be holistic and integrated, and implementable. The obligations of each affected entity must be clear, and an allocated credit of ZRCs is part of the proposal.

Q. What is the final outcome of the cost sharing proposal?

A. The utility ends up with 50 MW of ZRCs less a small capacity credit to the AES, <u>plus</u> the capacity, energy, and ancillary services value of the full 50 MW, <u>plus</u> a payment of (CONE – ACP) from the AES's pro rata share of the cost. The utility is more than whole financially, while at the same time the local reliability of the zone is maintained.

Q. Will you explain the second aspect of Energy Michigan's proposal, how LSEs can demonstrate capacity, preserving reliability after the LCR is met?

A. Once the zonal LCR is met, supply/demand reliability depends on the entire MISO region. As explained previously, MISO uses all resources to serve all load, and – once zonal LCR is met – <u>MISO has no constraints on who owns which ZRCs where</u>. Further, all ZRCs that clear the MISO auction are dedicated to MISO for the Planning Year.

Consequently, MISO has control of all capacity resources no matter who owns the rights to the ZRCs from those resources.

This implies that – again, once zonal LCR is met – ownership of, contract with, or ability to acquire any ZRC in MISO makes no difference to local reliability.

Section 6w(6) states:

> (6) A capacity charge shall not be assessed for any portion of capacity obligations for each planning year for which an alternative electric supplier can demonstrate that it can meet its capacity obligations through owned or contractual rights to any resource that the appropriate independent system operator allows to meet the capacity obligation of the electric provider. The preceding sentence shall not be applied in any way that conflicts with a federal resource adequacy tariff, when applicable. [Section 6w(6), emphasis added.]

As explained previously in Part II-B of my testimony, the MISO resource adequacy tariff allows four ways for LSEs to meet capacity obligations:

> *"LSEs will meet their PRMR by:*
>
> *(i) submitting a Fixed Resource Adequacy Plan;*
>
> *(ii) Self-Scheduling ZRCs;*
>
> *(iii) purchasing ZRCs through the Planning Resource Auction process; and/or*
>
> *(iv) paying the Capacity Deficiency Charge."*
>
> MISO Tariff, Module E-1, section 69A.

Energy Michigan proposes that the <u>demonstration of capacity</u> in the implementation of the SRM under Section 6w be <u>allowed to use (i), (ii), and (iii)</u> of the above – submitting a FRAP, self-scheduling ZRCs, and purchasing ZRCs through the Planning Resource Auction. Any and all of these three methods will neither increase nor decrease reliability. None of them "conflicts with a federal resource adequacy tariff" because each is in the MISO resource adequacy tariff.

Energy Michigan's proposal eliminates the illogical and contradictory situation that an LSE will be able to meet its resource adequacy needs to MISO according to the MISO tariff but not able to use the same resources to meet its "demonstration" of capacity under PA 341. It thus accords with PA 341's requirement that the SRM not conflict with the MISO resource adequacy tariff. See Section 6w(6).

Q. The third aspect of Energy Michigan's proposal is a recommended capacity charge for those LSEs who do not demonstrate sufficient capacity. What is your proposal?

A. My proposal for an SRM capacity charge for those LSEs who do not demonstrate sufficient capacity is the zonal Cost of New Entry, the CONE.

Q. Why do you think that CONE is the appropriate price?

A. CONE represents the cost of a newly built capacity product that MISO defines as meeting capacity requirements. It is also the highest cost that can be seen in the MISO auction. As shown previously in my testimony, DTE has stated that if it has to acquire capacity for deficient LSEs, it will either buy in the MISO auction or build new. Thus, the CONE is in accordance with cost of service principles.

Theoretically, if DTE were to buy in the auction, the cost of service price would be the Auction Clearing Price, which is less than or equal to CONE. Practically, however, pricing the SRM capacity charge for a deficient LSE at the ACP would make the deficient LSE financially indifferent to meeting its capacity requirement by paying the ACP to MISO or being deficient under PA 341 and paying the ACP to the utility. Therefore, charging CONE would provide an incentive to the LSE to meet its requirements through MISO while at the same time following Michigan's cost of service principles should the LSE fail to meet its requirements through MISO.

Q. DTE has submitted an historical embedded cost approach to determining the SRM capacity charge, relying on language in PA 341, Sub-sections 6w(3)(a) and (b). Would this approach be reasonable?

A. As discussed previously, there are two laws that will affect the implementation of the SRM charge – Section 6w(3), which is MCL 460.6w(3), and MCL 460.11(1), which is the cost of service statute. The Commission will have to determine the SRM charge in light of both laws. Energy Michigan will address this legal issue in briefs.

In this context, "cost of service" does not mean "the Excel file the utility normally uses in its rate case." Instead, it means discerning the principles of reasonably allocating a number of individual and joint costs, fixed and variable, to the customers or classes that affect the incurrence of such costs. If it has to take on additional capacity obligations under PA 341, DTE has stated it intends to buy from the MISO auction or build new. It is not going to use its existing resources to provide for additional capacity obligations, and therefore the cost of existing resources may not be relevant.

Further, PA 341 can be ambiguous. Section 6w(3) speaks to "capacity-related" and "non-capacity-related" electric generation costs, yet gives no definition of those terms. The section also specifies the subtraction of "all energy market sales." Since all the output of all generation is sold to the MISO energy market, and all energy delivered to LSEs is bought from the MISO energy market, face-value interpretation of "all energy market sales" means all energy sales, not energy sales less energy purchases. It would be incorrect to <u>net</u> MISO sales against purchases from MISO and subtract the <u>net</u>, as DTE has done in its proposed calculation of the SRM charge. As noted previously, Energy Michigan witnesses Mr. Jennings and Mr. Smith will address the practical application of pricing methods in their testimonies.

Q. The fourth aspect of Energy Michigan's proposal is how to implement its proposals over the four-year outlook that Section 6w calls for. What is your recommendation?

A. Various requirements and procedures in the MISO tariff apply only to the current Planning Year and the next upcoming Planning Year, in MISO jargon called the "prompt year." Section 6w, however requires a four-year look ahead, for which MISO does not have an equivalent.

Under Energy Michigan's proposal, some of the otherwise problematic issues of extending requirements four years ahead either go away or become much simpler to solve. For example, under the proposal for cost sharing of new intra-zonal utility resources, the cost sharing is an annual amount that extends over the life of the asset, and this eliminates the issue of the obligation and the method to pay for maintaining the LCR four years ahead.

As for the demonstration of capacity, MISO creates ZRCs and defines a FRAP only one year ahead. MISO also allows "purchasing ZRCs through the Planning Resource Auction process" as noted previously. Because MISO's tariff constructs and PA 341 do not coincide, and yet the statute requires that PA 341 "not be applied in any way that conflicts" with the MISO rules, the Commission will have to determine how to reasonably interpret the requirements of PA 341 so that they can be met by normal business processes, whether utility or AES. See Section 6w(6).

Energy Michigan's proposal is that normal business processes that work for the current and prompt year in MISO be allowed to work four years ahead also, with accommodation for the practicalities of time. A utility or AES that owns rights to ZRCs in the current or prompt year should be able to attest to and/or present a contract for delivery of future year ZRCs in the out years. Since ZRCs are not defined until the prompt year, demonstration by contract would also involve a second step of attesting to the actual "delivery" of ZRC rights when available for the prompt year, supported by MISO reports. Buying and selling ZRCs goes on all the time, and therefore demonstration by a utility or

AES should be able to be updated each year, using the mix of FRAP, ZRC contracts, and planned purchases from the MISO auction.

Energy Michigan's proposal is that future auction purchases can be used for demonstration in the out years. MISO will have access to and control of all resources. It makes no difference to reliability who owns which resources. "Buying in the auction" means paying MISO money that MISO will deliver to the owners of all ZRCs. Whether an LSE "buys in the auction" or owns a contract for future ZRCs is strictly a financial business decision. The zonal location of ZRCs in the auction is irrelevant, because specific ZRCs are not assigned to specific LSEs. Again, MISO ends up buying all capacity and using all capacity.

DTE sees no problem with it participating in the MISO auction to provide capacity for Electric Choice customers. Buying in the auction is not prohibited to either utilities or AESs under the Act and should be allowed by the Commission.

Wording in Section 6w for demonstration of capacity is identical for a utility and for an AES:

> . . . each <u>electric utility</u> demonstrate . . . the electric utility owns or has contractual rights to sufficient capacity to meet its capacity obligations as set by [MISO], or commission, as applicable. [6w.(8)(A)]
>
> . . . each <u>alternative electric supplie</u>r . . . demonstrate . . . the alternative electric supplier . . . owns or has contractual rights to sufficient capacity to meet its capacity obligations as set by [MISO], or commission, as applicable. [6w.(8)(B)]

Therefore, it would be a contradiction of both logic and the statute for the Commission to exclude from "demonstration" criteria the ability for an AES to use the MISO auction when the remedy that DTE proposes for failure to demonstrate sufficient capacity is for DTE to buy additional capacity in that same auction.

VII. BENEFITS OF ENERGY MICHIGAN'S PROPOSAL

Q. What are the benefits of Energy Michigan's proposal?

A. The benefits of Energy Michigan's proposal for implementing Section 6w of PA 341 are:

Maintains LCR: The cost sharing <u>*maintains the current quantity of local resources –*</u> <u>which is ample for maintaining reliability</u>. Zone 7 is a no-electric-growth area. Thus, as present resources are <u>*retired and replaced*</u>, sufficient LCR resources are maintained. All LSEs pay a share of the capacity value of the new resources, according to benefits received.

Follows COS: The proposal harmonizes the cost-of-service statute with PA 341 because AESs pay only for services they receive. <u>Utilities assert</u> they do not have capacity to provide for ROA customers and that <u>any services will either be from new resources or the MISO auction</u>.

Visible Price: CONE is a visible cost of <u>the capacity product</u> that MISO has determined meets its capacity requirements. Use of CONE eliminates arguing over allocations, embedded nuclear costs, etc.

Utility Freedom: Utility is free to build any type of generation it chooses. Only the cost of the pure capacity attribute gets into the SRM, not all the fixed costs of the generating facility. The utility retains the value of low energy costs, ancillary services revenue, etc.

Solves Customer Switching Problem: MISO customer switching presently involves the transfer of a customer's Peak Load Contribution ("PLC") priced at ACP from the old LSE to the new. SRM switching can follow the same method, using the "LCR charge" instead of the ACP, and switching the charge from the old AES to the new AES.

Simplifies Duration: CONE is an annualized charge, continuing for the life of the asset. Eliminates "30-year duration" issue because all customers would be paying on any new capacity investment for the life of that asset.

Simplifies "Return to Service": Eliminates need for changes in return-to-service rules. There is no longer a "before" or "after" demonstration-of-capacity issue because the AES is always (a) paying its share of cost of LCR provided by the utility and (b) paying its capacity obligation to MISO through either ZRCs submitted or the annual auction.

Eliminates "Interruptible" Discrimination: Utility and AESs pay pro-rata proportion, so customers of both should receive the same zonal reliability.

Eliminates Discrimination: All LSEs in the utility service area pay for the benefits of new resources that meet the zonal LCR. All LSEs receive the same reliability.

Opportunities for discrimination between full-service and Choice customers are thereby removed as all are treated the same under the Energy Michigan proposal.

Follows Used-and-Useful Principle and Cost-of-Service: Energy Michigan's proposal accords well with utility ratemaking principles such as used-and-useful and cost-of-service. The utility is paid for new plant in service and does not collect money in advance without any commensurate costs. Customers do not pay for zero benefits, and only incur charges for costs that they impose on the system.

Allows Regulatory Review Under Existing Structures: In Michigan, a utility is free to build or not build resources – regulation governs only the recovery of costs. The existing Certificate of Necessity process provides a review of the prudent investment in new resources, preventing the utility from overbuilding and collecting excessive SRM charges. Energy Michigan's proposal relies on existing regulatory structures to ensure fair implementation of the charge.

Incremental Pricing for Demonstration: The SRM charge for failure to demonstrate capacity is the CONE, and thus uses incremental cost-of-service elements that are in accordance with DTE's stated method of acquiring any additional needed capacity – *i.e.*, via the MISO auction or a newly built resource.

Q. What if there is not enough capacity in MISO?

A. That is an often-asked question. At the outset, the question implies that if there is "not enough capacity," that something catastrophic and intolerable is going to happen. There are four perspectives from which to answer the question – practical, legal, statistical, and logical.

Considering practicality, we have to look at the evidence that the situation in the question has a realistic potential to exist, and therefore requires an answer that incorporates a remedy. The observable evidence at present is outlined below.

1. ***Something* is working that is providing more capacity, even if we don't understand why.** MISO has been underreporting future capacity for 10 years. That is why in previous MISO reports, there was generally an image of a shortfall of capacity from a few to several years out, but when those years actually arrived, there was excess capacity. There is a large amount of capacity under development in MISO. In the past, almost all of this capacity under development was excluded from survey results, but starting this year, a realistic portion of it is now included. As a result, there is no longer a projected shortfall. The latest 2017 MISO/OMS report shows reserve margins of about 20% through 2022. Exhibit EM-4 (AJZ-4) shows pages from the recent 2017 MISO/OMS study illustrating this.[7] I have explained this exhibit in more detail in Part IV of my testimony.

[7]"2017 OMS MISO Survey Results," July 2017. Cited in Part IV of this testimony.

So if the question is asked in the context of what will happen if more capacity is not built to meet an expected shortage, then the answer is that there not only exists ample capacity for several years out, but also capacity is under development now that will meet demand decades out.

2. **MISO uses all to serve all.** Thus, when a customer moves from one supplier to another, the capacity used to serve that customer <u>still exists</u> in the market place. From MISO's perspective, total load stays the same, and total supply stays the same. Consequently, <u>no additional capacity is needed, only a change in financial responsibility to pay for that capacity</u>. So if the question is asked in the context of a customer switching to a different supplier and the underlying assumption is that somehow the new supplier has to "go out and get capacity," the answer is that the capacity already exists and the supplier need only pay for it. Energy Michigan's proposal provides how that supplier will pay for it.

3. Low growth means no surprises. Michigan is a no-electric growth area and MISO is a very low growth region. Consequently, there is not going to be a need for a large amount of additional capacity that is unanticipated. So if the question is asked in the context of "all of sudden we will have to do something," then the answer is that at least for the one to four years required to build new physical capacity, there is no need to plan additional capacity, and so no need to do something right now for a situation that has not emerged as an immediate problem. And, point 2 above addresses longer term concerns.

Q. What about legally?

A. By "legal perspective" I mean the role of agencies and rules that govern electric reliability. For Zone 7 in Michigan MISO governs reliability. MISO states its mission as: "Maintaining and managing reliability is MISO's most important job," [8] which includes both transmission and supply reliability. MISO's rules are approved by the Federal Regulatory Energy Commission, mostly in contested proceedings.

MISO is part of the North American Electric Reliability Corporation ("NERC"). NERC describes its responsibilities as:

> The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose <u>mission is to assure the reliability and security of the bulk power system in North America</u>. NERC develops and enforces Reliability Standards; annually assesses seasonal and long‐term reliability; monitors the bulk power system through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. <u>NERC is the electric reliability organization for North America, subject to oversight by the Federal Energy Regulatory Commission</u> and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the bulk power system, which serves more than 334 million people.[9] [Emphasis added.]

So if the question is asked in the context of "who is paying attention to reliability," then the answer is that there are regional, national, and federal organizations whose responsibility is to maintain electric reliability. Now, a follow up question might be, "Can they be trusted to do the job?", but that is a question that can always be asked of

[8] https://www.misoenergy.org/WhatWeDo/Pages/Reliability.aspx

[9] http://www.nerc.com/Pages/default.aspx.

any entity. For MISO under NERC, the track record for supply/demand reliability has been flawless since the establishment of MISO in the early 2000s and, from the recent MISO/OMS survey, there is no reason to expect that not to continue for the foreseeable future.

Q. What about statistically?

A. Reliability is a statistical measure, and thus the test of situations against reliability standards should be considered on a statistical basis. The unqualified question of, "What if there is not enough capacity?" is a discrete event. By the standard metric used by MISO of 24 loss of load hours in 10 years, as I have explained previously, the answer to the question is that "not enough capacity" is expected to occur on perhaps 4-8 days over a 10-year period statistically, and that has been the social and economic decision-point reached in trading off higher reliability against higher cost. "Not enough capacity" is not an event that is never expected to happen or that never should happen, as ensuring that it never could possibly happen is cost-prohibitive. "Not enough capacity" is a scenario that is considered in and expected to occur in reliability modeling, although the likelihood of such an event happening is extremely low. Testing a discrete event against a statistical method does not mean that the discrete event will never happen. The reliability standard is "1 day in 10," not "never in forever."

Q. What about logically?

A. The question, "What if there is not enough capacity?" assumes an outcome contrary to any proposal to maintain reliability, and thus can be used as a debating tactic to rebut any proposal by merely assuming it will fail. That is, logically it assumes an end state contrary to the objective of the proposal, and then uses that assumption to rebut the proposal.

An example might be, "MISO operates from Carmel, Indiana. What if an asteroid falls on Carmel, Indiana?" The answer might be, "MISO also has a back up facility in Minneapolis." Yet then another question could be, "What if a second asteroid fell on Minneapolis?" And so on.

While the above is facetious, the point here is to distinguish a legitimate question regarding the potential for insufficient capacity – which can be addressed by facts and analysis – from a debate technique for which there is no meaningful answer. In short, the logical answer is that there is no reason to believe that, given what we know today, there is any basis for acting as if there will not be enough capacity in MISO to ensure resource adequacy for the foreseeable future.

VIII. EXAMPLE OF SRM CAPACITY CHARGE

Q. Would you provide an example of how the cost sharing of the SRM capacity charge is calculated?

A. Yes. I have prepared Exhibit EM-5 (AJZ-5) to illustrate the calculation of the SRM charge, proration to utility and two AESs, annual cost for each AES, and the capacity credit for each AES. While the numbers are for example purposes only, I have used values that are approximately what would be seen in Zone 7 and in the DTE Electric area. One exception is the Zone 7 Auction Clearing Price, where the value is DTE's projection of Zone 7 Auction Clearing Price for 2018 through 2021[10], approximately $106 per MW-year rather than the current 2017-2018, so that the effect of the ACP would be more visible.

Page 1 of Exhibit EM-5 (AJZ-5) sets up a scenario of an example current status, with a hypothetical addition of a new 350 MW plant within the zone. Page 2 shows the calculation of the charge for the pro rate sharing of capacity costs of the new plant, where each LSE pays a share because the plant would maintain the Local Capacity Requirement in the zone under Energy Michigan's proposal. Page 2 shows how much each AES would pay DTE, and what each AES would receive as a capacity credit, again under Energy Michigan's proposal.

IX. ADDITIONAL ISSUES

Q. DTE witness Mr. Timothy A. Bloch, on page 10 of his Direct Testimony, proposes a number of changes to DTE's Retail Access Rider – EC2 tariff. Do you agree with the proposed tariff changes and can you respond to these in general?

A. There are a great many proposed changes, which are shown in Exhibit A-12, Schedule 2. Mr. Bloch puts them in categories:

[10] Case No. U-18143, DTE Electric 2017 PSCR Plan, Exhibit A-4, page 1 of 1. Average of four years 2018-2021 is $38.83 per kW-year, divided by 0.365, yielding $106.38 per MW-year.

> There are several proposed changes to the existing Retail Access Service Rider-EC2 to address the Company's obligation under PA341 to provide capacity service to Retail Access customers and to Retail Access customers returning to Full Service. The proposed changes generally include:
>
> 1) Redefining the roles and responsibilities of the Customer, AES and Company.
> 2) Adding definitions to distinguish energy service from capacity service.
> 3) Terms and conditions for Return to Full Service (i.e. Bundled Service) or Utility Capacity Service.
> 4) Potential Firm Service Limitations
> 5) Transferring from Utility Capacity Service to Bundled Service
>
> [Direct Testimony of Timothy A. Bloch, p. 10, lines 2-11.]

Exhibit A-12, Schedule 2 contains 17 pages, and well over half show substantive changes. Changes include notice provisions, 30-year "irrevocable" decisions, interruptible capacity service for Electric Choice customers, queuing of returning Electric Choice customers, and other changes – all relating to DTE's proposal for implementing PA 341.

In aggregate, these changes are excessively complicated, violate just and reasonable ratemaking practices, and are unneeded under Energy Michigan's proposal. Energy Michigan is opposed to all changes in the EC2 tariff that are made to implement DTE's proposed SRM mechanism. Furthermore, many of the proposed DTE changes to EC2 relate to matters that are being addressed in the Section 6w technical work group and so should not be the focus of this proceeding. Energy Michigan is addressing many of these issues in that workgroup, pursuant to the Commission's direction in its May 11 and June 15 Orders in U-18197.

Electric Choice has been in place in Michigan for over 16 years, and the return-to-service rules the Commission approved back in 2001 have worked well. If such rules are to change, the Commission should first require documented evidence of a problem with the existing rules.

Under Energy Michigan's proposal, DTE's proposed tariff changes are not necessary. As explained above, Energy Michigan's proposal eliminates the need for such changes because AESs will always be paying to DTE their shares of the cost of any new capacity built or obtained by DTE within the zone, which in turn will maintain reliability in the zone. Therefore, discrimination between "returning" Electric Choice customers and existing full service customers is not required.

Q. DTE's witness, Mr. Stanczak, on pages 15-16 of his Direct Testimony, proposes that a customer "returning" to either bundled service or "capacity only" service must pay for capacity for a 30-year period. What is your assessment of this proposal?

A. Energy Michigan is opposed to DTE's proposed 30-year commitment. First, as discussed above, under Energy Michigan's proposal, AESs would provide payment on any new capacity investment for the life of that asset, thus eliminating the need for any minimum SRM term. The concept of cost recovery is valid, but a separate duration rule for a particular customer is not. The 30-year duration is certainly not necessary under Energy Michigan's proposal, because Energy Michigan is proposing that pro rata payment for new intra-zonal capacity be for the life of the new resource. Energy Michigan has recognized that the utility needs reasonable cost recovery for new investment, and our proposal provides that.

DTE's proposed 30-year duration goes further, however, because it places the 30-year obligation on a specific customer, not on the time of overall cost recovery, thus limiting the customer's future choice of suppliers. I know of no other example of such a charge that would be placed on a customer for such a protracted period of time. On its face, such an extended duration would be punitive to the customer by limiting the customer's choice of suppliers and would not represent just and reasonable ratemaking under cost of service principles.

Q. How long is DTE proposing that customers pay the capacity charge in the first four years of the SRM?

A. DTE addresses this in its testimony:

> **Q. Should Choice customers choose to rely on the Company for generation capacity service, how long will they be obligated to pay the Company's capacity charge?**
> A. PA 341 (Section 6w(8)(b)(i)) <u>requires</u> that if Choice load pays the capacity charge in any one of the first four years that the SRM is in place, it must at a minimum, pay the capacity charge for all of the first four years of the SRM.
> [Direct Testimony of Stanczak, p. 8, line 19-23. Emphasis added.]

Q. Do you agree with this proposal?

A. No, not at all. I disagree with three aspects. First, to assert that customers are "choosing" to rely on the Company for generation capacity service under DTE's proposal appears to be at odds with the multiplicity of new rules and procedures that DTE is proposing for the implementation of the SRM. Second, it does not appear to me from a plain reading of the statute that Section 6w(8)(b)(i) requires payment for all four years of the initial period. Third, an interpretation of required payment for all four years leads to an unjust result.

Section 6w(8)(b)(i) states:

> If a capacity charge is required to be paid under this subdivision in the planning year beginning June 1, 2018 or <u>any</u> of the 3 subsequent planning years, the capacity charge is applicable for <u>each</u> of <u>those planning years</u>. [PA 341, Section 6w(8)(b)9i). Emphasis added.]

The question becomes, what are "those planning years"? To me, the antecedent of "those" is "any" of the years that a capacity charge is required to be paid. That's why "each" is in the clause, rather than "all four." But it doesn't say "all four." It says <u>each</u> of <u>those</u> planning years.

Regardless, the Commission has the task of interpreting the statute, and Energy Michigan will address the issue in its brief. In practical application, I will give an example of how interpreting the statute as paying in all four years even if deficient in one year leads to an irrational result. Suppose an AES's load is 100 MW, and it is deficient by 60 MW in year 2 and by 55 MW in year 3. Does it pay the capacity charge on 60 MW for 4 years plus the capacity charge on 55 MW for 4 years? That would be DTE's interpretation and proposal. If so, it would be paying for 115 MW for 4 years when its forecast load is only 100 MW. That would not make sense. And the additional rules to have this situation make sense not only would be complicated but also are not called for in the statute.

Given the plain meaning of the statute, it would seem that a sensible interpretation for the Commission would be that, for the initial 4-year period, the AES should get one chance to demonstrate capacity and cannot, within that initial 4-year period, remedy a deficiency once it is declared. That is, for <u>any</u> year in the initial 4-year period that the AES has a deficiency, it pays the capacity charge for <u>each</u> of <u>those</u> years in which there is a deficiency. If the Commission were to make this interpretation, then (a) the AES is treated fairly – it must demonstrate or pay only for the years it is deficient; (b) the utility is treated fairly – no excess capacity charge collection is made if there is no deficiency in a year; and (c) the outcome is always sensible – no possibility of paying for more capacity than the AES has load.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

****

In the matter, on the Commission's own motion,	)	
to open a docket to implement the provisions of	)	
Section 6w of 2016 PA 341for	)	**Case No. U-18248**
DTE ELECTRIC COMPANY'S	)	
service territory.	)	
	)	

EXHIBITS OF

ALEXANDER J. ZAKEM

ON BEHALF OF

ENERGY MICHIGAN, INC.

ALEXANDER J. ZAKEM

46180 Concord
Plymouth, Michigan 48170
734-751-2166
ajzakem@umich.edu

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 : **<u>DTE Energy / Detroit Edison — 1977 to 2001</u>**

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

<u>Position</u>	***<u>Organization</u>***	***<u>Time Period</u>***
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.

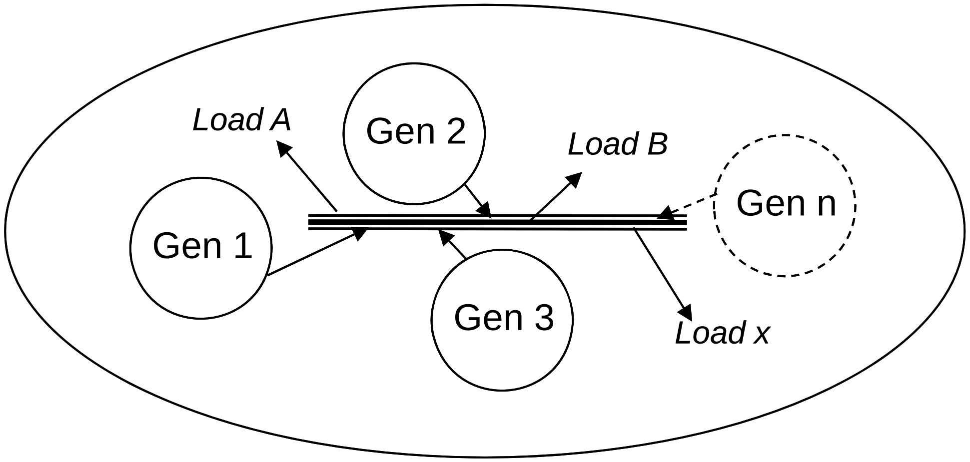
PREVIOUS TESTIMONY:

- Michigan Public Service Commission, U-18239
- Michigan Public Service Commission, U-18014
- Michigan Public Service Commission, U-17990
- Michigan Public Service Commission, U-17767
- 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.

"Collective Reliability" via MISO Pool

- *MISO aggregates and dispatches virtually <u>all the generation</u> in its region to serve the <u>aggregated load</u> in the region.*
- *All resources serve all load.*
- *Therefore, each Load Serving Entity (LSE) is equally reliable on a generation basis.*

MISO Region
injection & withdrawal of energy



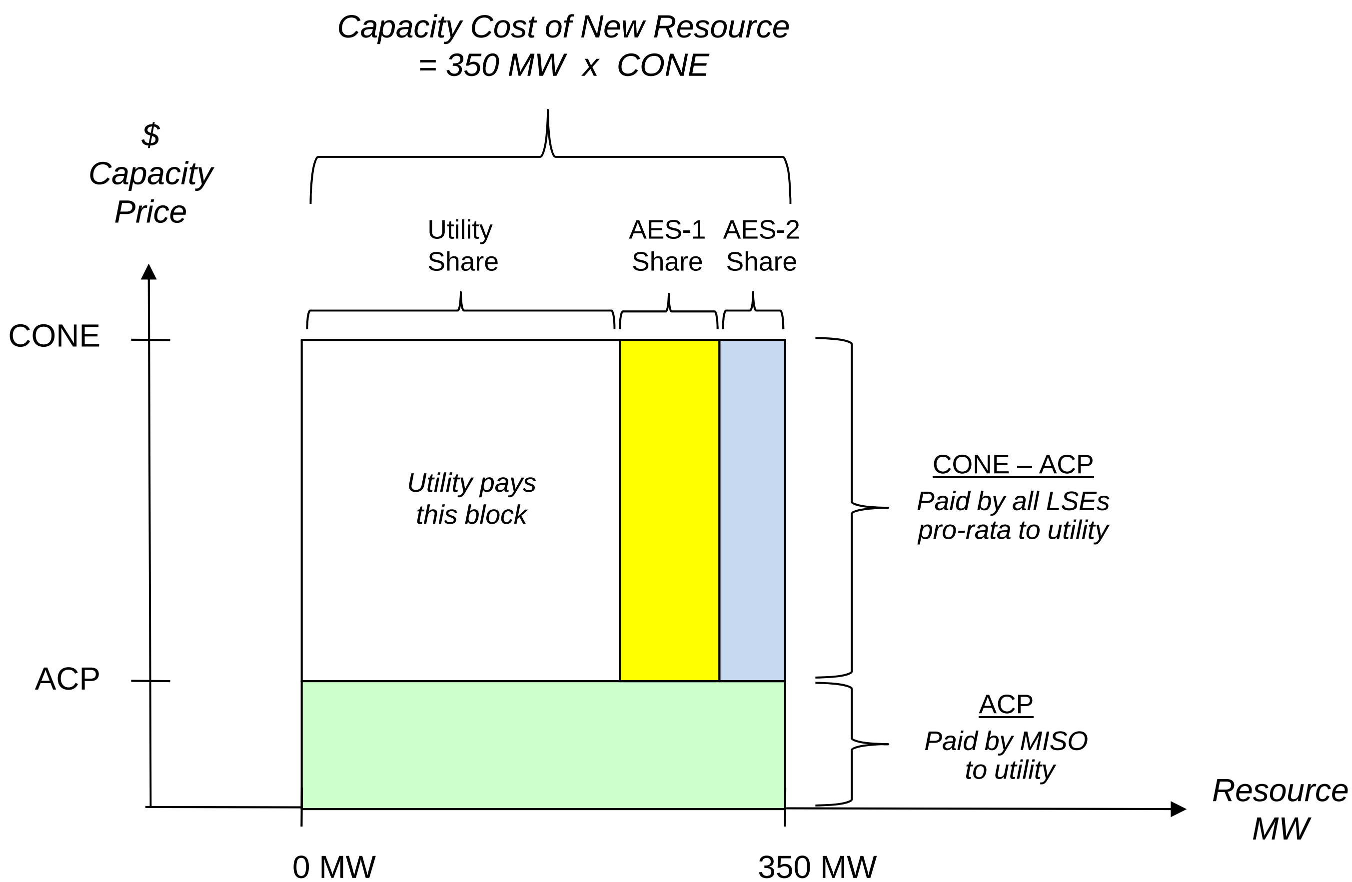
a. **All Resources Serve All Load** – It is not accurate to claim that specific generators serve specific loads – for example, that "Utility A's customers are served by the Utility A's generation."

b. **Customer Switching Does Not Affect Reliability** -- If a customer switches from Supplier A to Supplier B, the total regional load does not change, nor does the generation dispatch.

c. **Generation Hedge** -- Ownership of generation provides a <u>financial hedge</u> against variable market prices, but <u>does not increase or decrease reliability</u> for the supplier's own customers.

d. **Capacity is Fungible --** If a customer switches from Supplier A to Supplier B, then MISO automatically reduces Supplier A's capacity obligation and increases Supplier B's capacity obligation. Supplier B does not have to "go out and get more capacity."

Example Cost Sharing of 350 MW New Resource



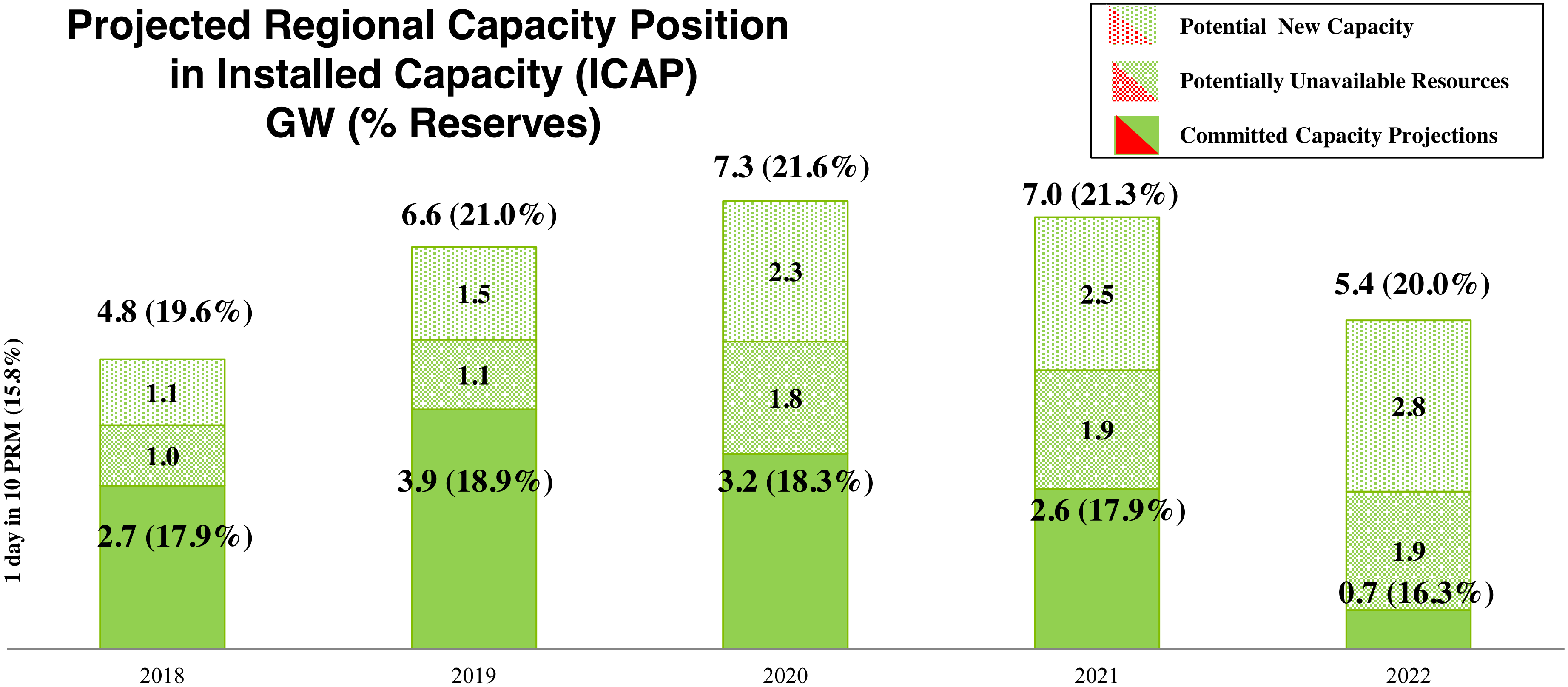
- Utility constructs 350 MW qualified new resource.
- AES-1 PRMR is 10% of distribution area PRMR.
- AES-2 PRMR is 5% of distribution area PRMR.
- Utility PRMR is 85% of distribution area PRMR.

2017 OMS MISO Survey Results

Furthering our joint commitment to regional resource assessment and transparency in the MISO region, OMS and MISO are pleased to announce the results of the 2017 OMS MISO Survey

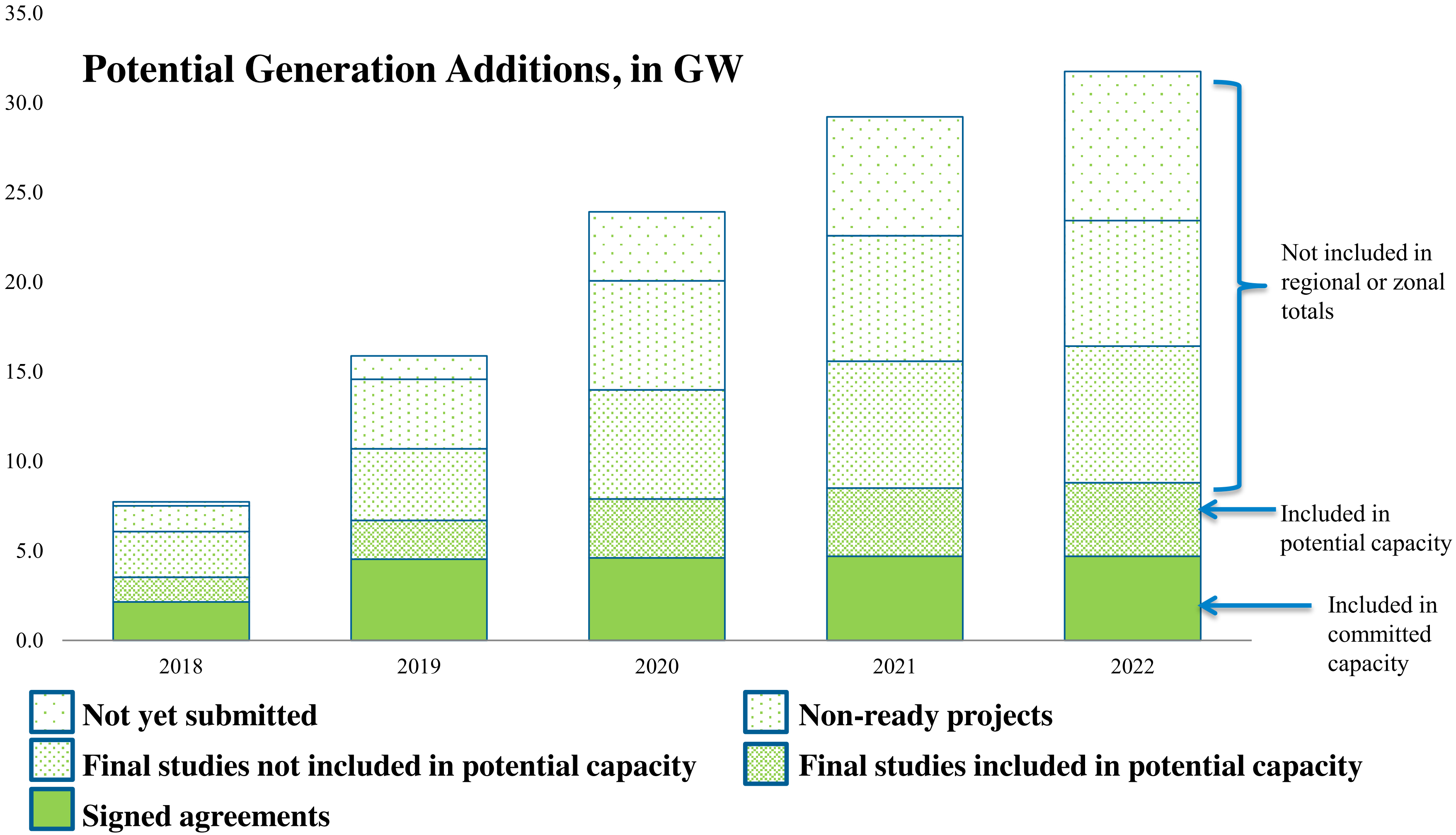
July 2017

Existing resources, potential retirements, and new resources create a range of resource balances



- Regional outlook includes projected constraints on capacity, including Capacity Export Limits and the Sub-regional Power Balance Constraint
- These figures will change as future capacity plans are solidified by load serving entities and state commissions.
- **Potential New Capacity** represents 35% of the capacity in the final stage of the MISO Generator Interconnection queue, as of May 11, 2017.
- **Potentially Unavailable Resources** includes potential retirements and capacity which may be constrained by future firm sales across the Sub-regional Power Balance Constraint

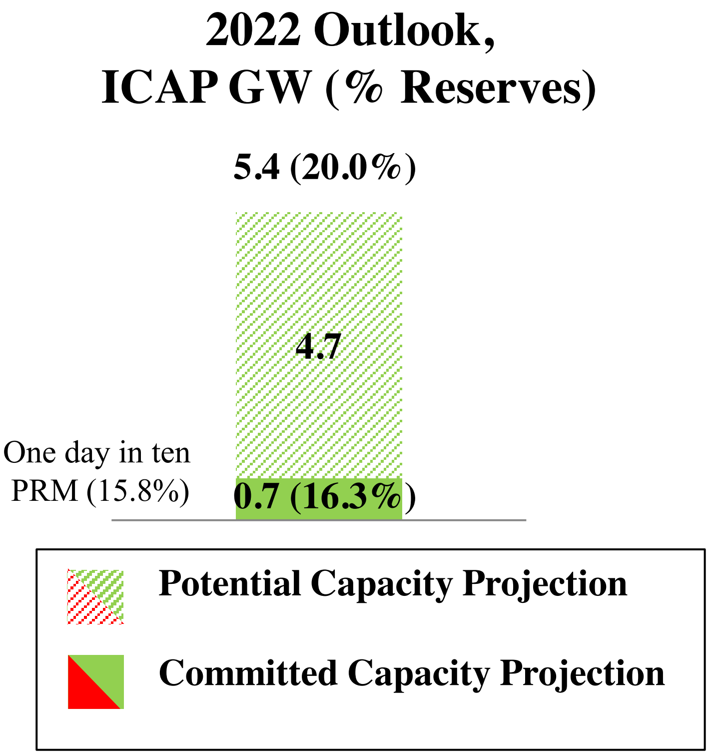
Future resource ranges will shift as planned generation interconnections are firmed up

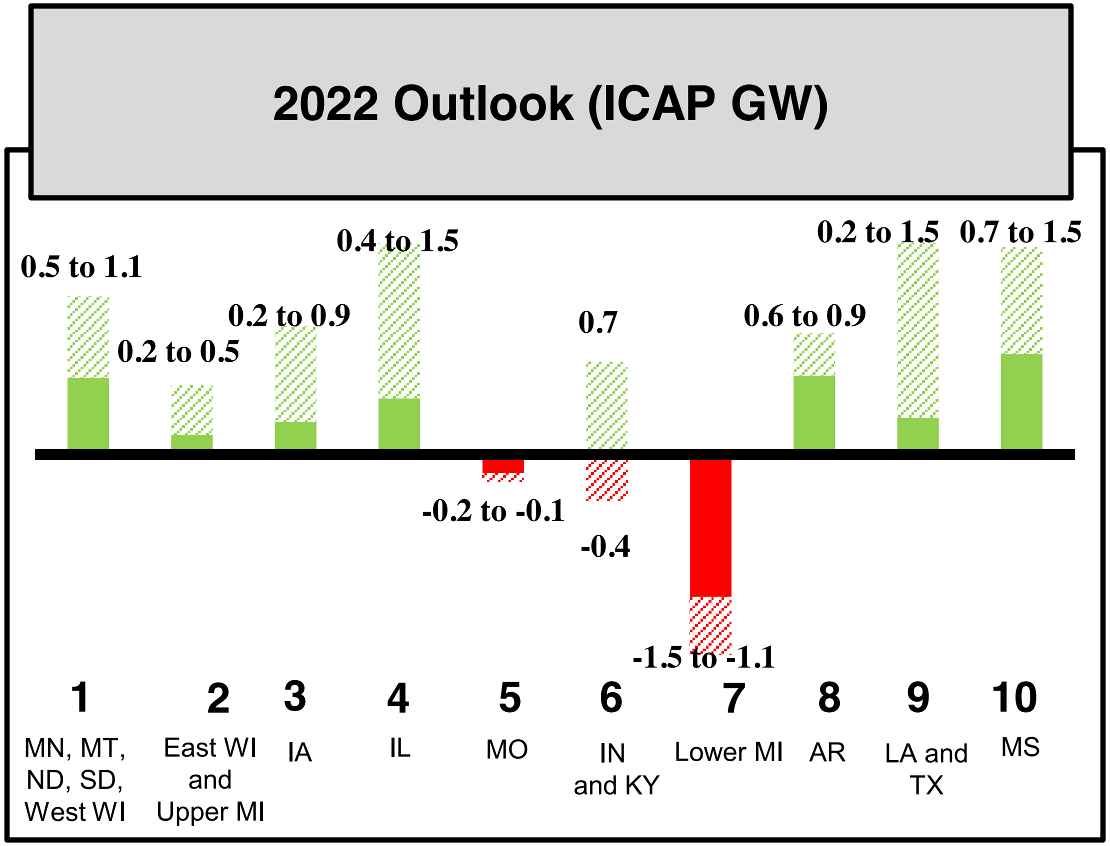


Wind and solar resources are represented at their expected capacity credit

Non-ready projects will be deemed withdrawn, as of June 15th, with an option to move to final studies

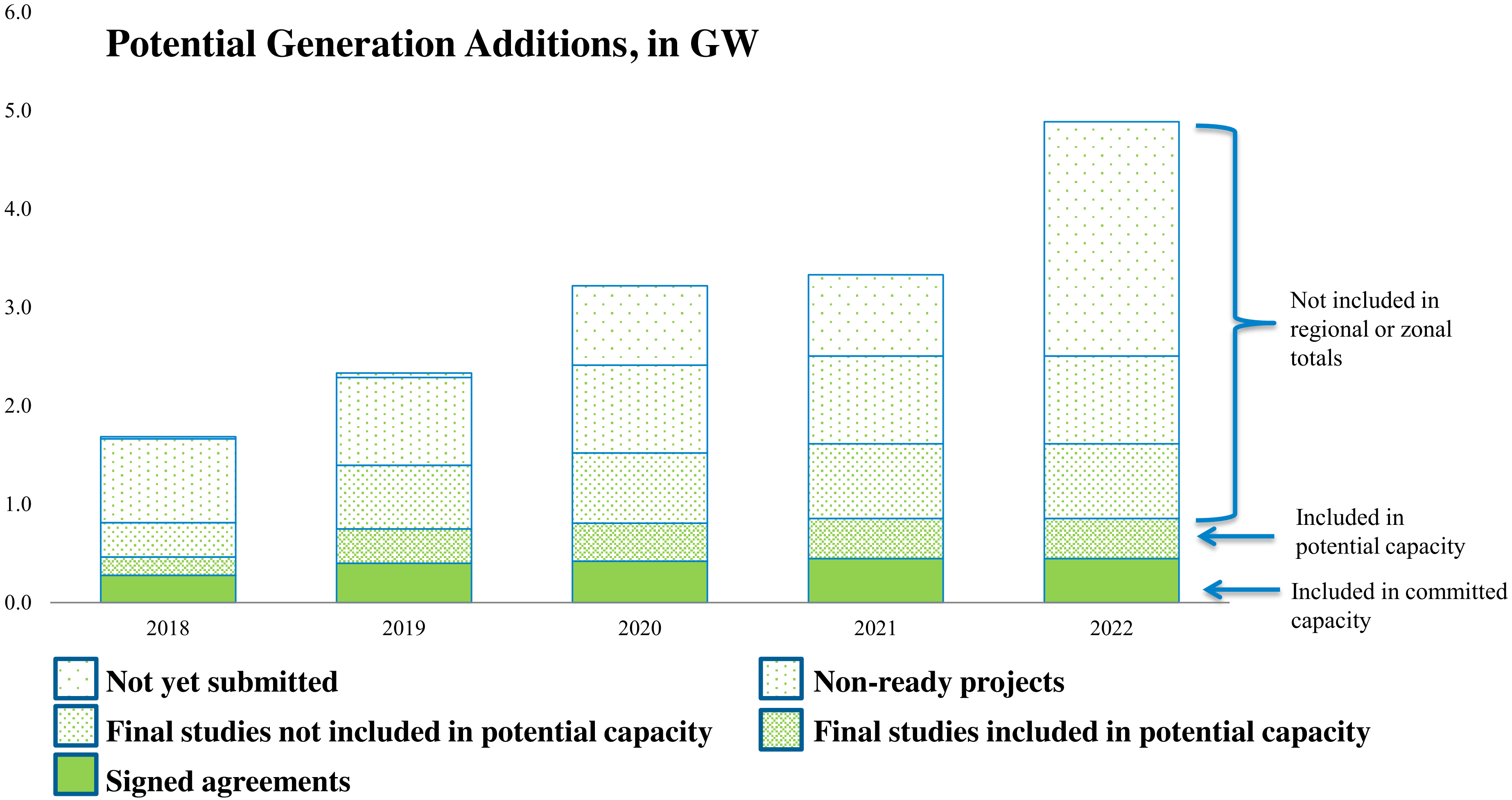
Continued focus on load growth variations and generation retirements will reduce uncertainty around future resource adequacy assessments





- Regional surpluses and potential resources are sufficient for all zones to serve their deficits while meeting local requirements
- Positions include reported inter-zonal transfers, but do not reflect other possible transfers between zones
- Results include load, but not identified resources, from some non-jurisdictional load in Zone 5
- Exports from Zones 8, 9, and 10 were limited by the Sub-regional Power Balance Constraint to 1.5 GW in committed capacity projections and 1.9 GW in potential capacity projections

Zone 7 New Resource Additions by Queue Phase



Wind and solar resources are represented at their expected capacity credit

Non-ready projects will be deemed withdrawn, as of June 15th, with an option to move to final studies

Cost Sharing Calculations

Scenario

IF:

• 94.7%	Zone 7 LCR percent.
• 11,000 MW	~ DTE service area PRMR.
• $94,900	Zone 7 CONE, $ per MW-year.
• $38,690	Zone 7 ACP, $ per MW-year, = $106 x 365 days.
• 400 MW	AES #1 PRMR.
• 300 MW	AES #2 PRMR. Owns 100 MW within Zone 7.

THEN:

• 10,417 MW	Service area share of LCR, = 11,000 x 94.7%.
• 379 MW	AES #1 share of LCR, = 400 x 94.7%
• 184 MW	AES #2 share of LCR, = (300 x 94.7%) – 100.

- Suppose DTE builds a new ~ 350 MW (ZRC rating) plant to replace a retiring unit.

Cost Sharing Calculations
(continued)

Results

- Suppose DTE builds a new 350 MW plant to replace a retiring unit.
- Then

"LCR charge" = 350 x (94,900 – 38,690) / 10,417 = **$1,886 per MW**.

AES #1 owes utility $714,794 annually for its 379 MW share.
= $1,886 x 379 MW

AES #2 owes utility $347,024 annually for its 184 MW share.
= $1,886 x 184 MW

ZRC Credit

MW credit = MW new resource x (LCR AES / LCR area) x (CONE-ACP)/CONE

For AES #1 = 350 MW x (379 / 10,417) x (94,900 – 38,690)/94,900 = 350 x 3.64% x 59.2%
= 7.5 MW

For AES #2 = 350 MW x (184 / 10,417) x (94,900 – 25,550)/94,900 = 350 x 1.77% x 59.2%
= 3.7 MW

DTE Electric Company
One Energy Plaza, 688 WCB
Detroit, MI 48226-1279

DTE Energy

David S. Maquera
(313) 235-3724
david.maquera@dteenergy.com

September 30, 2016

Ms. Kavita Kale
Executive Secretary
Michigan Public Service Commission
7109 West Saginaw Highway
Lansing, MI 48917

RE: In the matter of the Application of DTE Electric Company for Authority to Implement a Power Supply Cost Recovery Plan in its Rate Schedules for 2017 Metered Jurisdictional Sales of Electricity
MPSC Case No. U-18143

Dear Ms. Kale:

Attached for electronic filing in the above captioned matter is DTE Electric Company's 2017 PSCR Plan Application, along with supporting Testimony and Exhibits. Also attached is the Proof of Service.

Very truly yours,

David S
Maquera

David S. Maquera

DSM/lah
Encl.
cc: Service List

Michigan Public Service Commission
DTE Electric Company
Projected Wholesale Energy, Capacity, & Emission Allowance Prices
Years 2017 - 2021

Case No.: U-18143
Exhibit: A-4
Witness: S. D. Burgdorf
Page: 1 of 1

Line No.	(a)	(b)	(c)	(d)	(e)	(f)
1		**Michigan Hub Energy Price Forecast**				
2	**Month**	**OnPeak**	**OffPeak**	**OnPeak**	**OffPeak**	**RTC**
3		($/MWh)	($/MWh)	(hours)	(hours)	($/MWh)
4	Jan-2017	42.42	34.18	336	408	37.90
5	Feb-2017	40.27	29.58	320	352	34.67
6	Mar-2017	35.22	28.78	368	376	31.96
7	Apr-2017	34.52	22.98	320	400	28.11
8	May-2017	34.77	22.88	352	392	28.50
9	Jun-2017	34.17	22.68	352	368	28.29
10	Jul-2017	41.62	26.08	320	424	32.76
11	Aug-2017	37.37	23.43	368	376	30.32
12	Sep-2017	33.12	22.98	320	400	27.48
13	Oct-2017	31.57	23.63	352	392	27.38
14	Nov-2017	32.82	23.58	336	384	27.89
15	Dec-2017	34.97	26.78	320	424	30.30
16	Jan-2018	43.67	34.18	352	392	38.67
17	Feb-2018	40.67	31.23	320	352	35.72
18	Mar-2018	35.67	26.43	352	392	30.80
19	Apr-2018	31.97	24.63	336	384	28.05
20	May-2018	34.07	21.43	352	392	27.41
21	Jun-2018	34.27	22.28	336	384	27.87
22	Jul-2018	41.12	24.63	336	408	32.07
23	Aug-2018	37.12	23.93	368	376	30.45
24	Sep-2018	32.67	22.38	304	416	26.72
25	Oct-2018	31.57	22.93	368	376	27.20
26	Nov-2018	31.92	23.33	336	384	27.34
27	Dec-2018	34.57	25.18	320	424	29.22
28	Jan-2019	42.82	34.33	352	392	38.34
29	Feb-2019	39.57	32.13	320	352	35.67
30	Mar-2019	32.82	28.23	336	408	30.30
31	Apr-2019	29.92	24.28	352	368	27.03
32	May-2019	32.07	23.88	352	392	27.75
33	Jun-2019	32.77	24.48	320	400	28.16
34	Jul-2019	40.52	26.93	352	392	33.36
35	Aug-2019	36.62	25.18	352	392	30.59
36	Sep-2019	31.37	24.18	320	400	27.37
37	Oct-2019	29.67	24.03	368	376	26.82
38	Nov-2019	29.82	25.48	320	400	27.41
39	Dec-2019	32.27	25.18	336	408	28.38
40	Jan-2020	43.92	34.43	352	392	38.92
41	Feb-2020	39.47	32.93	320	376	35.93
42	Mar-2020	33.67	28.33	352	392	30.85
43	Apr-2020	30.97	23.68	352	368	27.24
44	May-2020	33.12	24.18	320	424	28.02
45	Jun-2020	33.22	24.13	352	368	28.57
46	Jul-2020	41.52	26.88	352	392	33.80
47	Aug-2020	36.27	26.13	336	408	30.71
48	Sep-2020	31.57	24.03	336	384	27.55
49	Oct-2020	30.32	24.23	352	392	27.11
50	Nov-2020	29.67	24.78	320	400	26.95
51	Dec-2020	33.82	26.93	352	392	30.19
52	Jan-2021	41.72	35.23	320	424	38.02
53	Feb-2021	37.82	31.88	320	352	34.70
54	Mar-2021	34.12	29.38	368	376	31.72
55	Apr-2021	32.12	23.38	352	368	27.65
56	May-2021	33.67	24.73	320	424	28.57
57	Jun-2021	33.87	24.13	352	368	28.89
58	Jul-2021	42.72	26.38	336	408	33.76
59	Aug-2021	37.17	25.78	352	392	31.17
60	Sep-2021	32.62	24.83	336	384	28.46
61	Oct-2021	31.22	23.63	336	408	27.05
62	Nov-2021	32.07	23.78	336	384	27.65
63	Dec-2021	33.62	27.23	352	392	30.25

(g)	(h)	(i)	(j)
	Emission Allowance Price Projections		
Year	**Annual NO_x**	**Seasonal NO_x**	**SO_2 (CSAPR)**
	($/ton)	($/ton)	($/ton)
2017	106.19	1107.79	3.08
2018	105.84	1122.44	3.15
2019	101.04	1136.98	3.23
2020	95.93	1136.05	3.32
2021	93.90	1098.22	3.41

Planning Year	**Capacity ($/kW-year)**
2016	26.28
2017	25.40
2018	24.39
2019	37.73
2020	50.31
2021	42.89
2017-2021 Avg	36.14

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

****

In the matter, on the Commission's own motion, to open a docket to implement the provisions of Section 6w of 2016 PA 341 for **DTE ELECTRIC COMPANY'S** service territory.	))))))	**Case No. U-18248**

DIRECT TESTIMONY & EXHIBITS OF

RALPH C. SMITH

ON BEHALF OF

ENERGY MICHIGAN, INC.

DIRECT TESTIMONY OF RALPH C. SMITH
TABLE OF CONTENTS

I. INTRODUCTION 2

II. STATE RELIABILITY MECHANISM CAPACITY COST RATE 10

A. Capacity Costs 11

B. The 75-0-25 Production Cost Allocator.. 12

C. Energy Market Sales Revenue, Off-System Energy Sales Revenue, and Ancillary Service Revenue, Net of Related Fuel Costs.. 16

D. Net Capacity Cost 17

E. DTE's Owned and Purchased Capacity in MW 18

F. Calculation of the State Reliability Mechanism Capacity Rate.............................. 18

G. Summary of Recommendation for SRM Capacity Rate.. 19

RALPH C. SMITH
DIRECT TESTIMONY

I. INTRODUCTION

Q. Please state your name and business address.

A. Ralph C. Smith. My business address is: Larkin & Associates, PLLC, 15728 Farmington Road, Livonia, Michigan 48154.

Q. By whom are you employed and in what capacity?

A. I am a senior regulatory consultant with Larkin & Associates, PLLC, a firm of CPAs and utility regulatory consultants.

Q. Please describe Larkin & Associates.

A. Larkin & Associates is a Certified Public Accounting and Regulatory Consulting firm. The firm performs independent regulatory consulting primarily for public service/utility commission staffs and consumer interest groups (public counsels, public advocates, consumer counsels, attorneys general, etc.). Larkin & Associates has extensive experience in the utility regulatory field as expert witnesses in over 600 regulatory proceedings including numerous telephone, water and sewer, gas, and electric matters.

Q. Mr. Smith, please summarize your educational background.

A. I received a Bachelor of Science degree in Business Administration (Accounting Major) with distinction from the University of Michigan - Dearborn, in April 1979. I passed all parts of the Certified Public Accountant ("CPA") examination in my first sitting in 1979, received my CPA license in 1981, and received a certified financial planning certificate in 1983. I also have a Master of Science in Taxation from Walsh College, 1981, and a law degree (J.D.) cum laude from Wayne State University, 1986. In addition, I have attended a variety of continuing education courses in conjunction with maintaining my accountancy license. I am a licensed C.P.A. and attorney in the State of Michigan. I am also a Certified Financial Planner™ professional and a Certified Rate of Return Analyst ("CRRA"). Since 1981, I have been a member of the Michigan Association of Certified Public Accountants. I am also a member of the Michigan Bar Association and have been a member of the Society of Utility and Regulatory Financial Analysts ("SURFA"). I have also been a member of the American Bar Association ("ABA"), and the ABA sections on Public Utility Law and Taxation.

Q. Please summarize your professional experience.

A. Subsequent to graduation from the University of Michigan, and after a short period in which I installed a computerized accounting system for a Southfield, Michigan realty management firm, I accepted a position as an auditor with the predecessor CPA firm to Larkin & Associates in July 1979. Before becoming involved in utility regulation where the majority of my time for the past 38 years has been spent, I performed audit, accounting, and tax work for a wide variety of businesses that were clients of the firm.

During my service in the regulatory section of our firm, I have been involved in rate cases and other regulatory matters concerning numerous electric, gas, telephone, water, and sewer utility companies. My present work consists primarily of analyzing rate case and regulatory filings of public utility companies before various regulatory commissions, and, where appropriate, preparing testimony and schedules relating to the issues for presentation before these regulatory agencies.

I have performed work in the field of utility regulation on behalf of industry, state attorneys general, consumer groups, municipalities, and public service commission staffs concerning regulatory matters before regulatory agencies in Alabama, Alaska, Arizona, Arkansas, California, Connecticut, Delaware, Florida, Georgia, Hawaii, Indiana, Illinois, Kansas, Kentucky, Louisiana, Maine, Maryland, Massachusetts, Michigan, Minnesota, Mississippi, Missouri, New Jersey, New Mexico, New York, Nevada, North Carolina, North Dakota, Ohio, Pennsylvania, Rhode Island, South Carolina, South Dakota, Tennessee, Texas, Utah, Vermont, Virginia, Washington, Washington D.C., West Virginia and Canada as well as the Federal Energy Regulatory Commission ("FERC") and various state and federal courts of law.

Q. On whose behalf are you appearing?

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

Q. Have you previously testified before the Michigan Public Service Commission ("MPSC")?

A. Yes. I testified before the MPSC in Case Nos. U-12604 and U-12613, involving Power Supply Cost Recovery Plans for the Calendar Year 2001 for Upper Peninsula Power Company and Wisconsin Public Service Corporation, respectively. I also testified on behalf of the Attorney General in Case No. U-14347, Consumer Energy Company's request for a rate increase.

Q. Have you previously testified before other utility regulatory commissions?

A. Yes. I have filed testimony and/or testified before the following utility regulatory commissions: Alaska, Arizona, Arkansas, California, Connecticut, Delaware, Florida, Georgia, Hawaii, Indiana, Illinois, Kansas, Kentucky, Maine, Maryland, Michigan, Minnesota, Mississippi, Missouri, New Jersey, New Mexico, New York, Nevada, North Carolina, North Dakota, Ohio, Pennsylvania, Rhode Island, South Carolina, South Dakota, Tennessee, Texas, Utah, Vermont, Virginia, Washington, Washington D.C., and West Virginia.

Q. Have you presented testimony on the establishment of a charge for utility capacity in another proceeding?

A. Yes. Along with a witness from Energy Ventures Analysis, Inc. ("EVA") I presented testimony on behalf of the Staff of the Public Utility Commission of Ohio ("PUCO") in Case No. 10-2929-EL-UNC, ***In the Matter of the Commission Review of the Capacity Charges of Ohio Power Company and Columbus Southern Power Company***. Those utilities have been merged into Ohio Power Company and are also collectively known as American Electric Power ("AEP") Ohio.

Q. Have you prepared an exhibit summarizing your educational background and regulatory experience?

A. Yes. Exhibit EM-7 (RCS-1), attached hereto, provide details concerning my experience and qualifications.

Q. What is the purpose of your testimony?

A. Larkin & Associates, PLLC (“Larkin”) and Energy Ventures Analysis, Inc. ("EVA") were engaged by Varnum LLP, counsel to Energy Michigan, to evaluate the capacity rate issues in DTE Electric Company ("DTE" or "Company") Case No. U-18248 ("Application") before the Michigan Public Service Commission ("MPSC" or "Commission"). The goal of the engagement was to develop and file a State Reliability Mechanism ("SRM") capacity charge rate consistent with the provisions of MCL 460.6w Section 3 and in response to the Company's Application. The statute provides that the capacity charge include the capacity-related generation costs included in the utility's base rates, surcharges, and power supply cost recovery factors (Section 3(a)) less the non-capacity-related electric generation costs from all of the following: (i) all energy market sales; (ii) off-system energy sales, (iii) ancillary service sales, and (iv) energy sales under unit-specific bilateral contracts. (Section 3(b)). EVA's specific scope was to forecast all items included in Section 3(b), which would then be utilized by Larkin to develop the capacity charge.

Q. What issues are addressed in your testimony?

A. On behalf of the Energy Michigan in this proceeding, I address the calculation of a State Reliability Mechanism capacity charge under MCL 460.6w(3)(a) and (b) and MCL 460.11. As I discuss below, MCL 460.11 requires that rates for electric service be based on the cost of service and discusses how a specific allocation factor of 75-0-25 should be applied to the electric utility's production costs. In the current proceeding, I address the development of a State Reliability Mechanism capacity charge for DTE Electric Company. The initial State Reliability Mechanism capacity charge for DTE would apply in 2018 and would be updated annually.

Q. Please describe the documents reviewed for this engagement.

A. Larkin reviewed applicable statutes, including MCL 460.6w and MCL 460.11, as well as DTE's filings in the current case and in some related cases, DTE's responses to discovery requests made by parties to this proceeding, including Energy Michigan, DTE's filings to the Securities and Exchange Commission ("SEC"), DTE's annual Form 1 filings to the FERC, and documents produced by the Midcontinent ISO ("MISO").

Q. Did DTE provide all the information that you requested?

A. No. As of the date of this writing, DTE has not yet provided some of the requested information.

Q. What are the provisions of MCL 460.6w?

A. In relevant part, MCL 460.6w states as follows:

> 460.6w Resource adequacy tariff that provides for capacity forward auction; option for state to implement prevailing state compensation mechanism for capacity; order to implement prevailing state compensation mechanism; contested case proceeding; finding; order to implement state reliability mechanism; capacity charge; establishment; determination; failure to meet requirements in subsection (8)(b); civil action for injunctive relief; definitions.
>
> Sec. 6w.
>
> (2) . . . If, by September 30, 2017, the Federal Energy Regulatory Commission does not put into effect a resource adequacy tariff that includes a capacity forward auction or a prevailing state compensation mechanism, then the commission shall establish a state reliability mechanism under subsection (8). The commission may commence a proceeding before October 1 if the commission believes orderly administration would be enabled by doing so. If the commission implements a state reliability mechanism, it shall be for a minimum of 4 consecutive planning years beginning in the upcoming planning year. A state reliability charge must be established in the same manner as a capacity charge under subsection (3) and be determined consistent with

> subsection (8).
>
> (3) After the effective date of the amendatory act that added section 6t, the commission shall establish a capacity charge as provided in this section. A determination of a capacity charge must be conducted as a contested case pursuant to chapter 4 of the administrative procedures act of 1969, 1969 PA 306, MCL 24.271 to 24.287, after providing interested persons with notice and a reasonable opportunity for a full and complete hearing and conclude by December 1 of each year. The commission shall allow intervention by interested persons, alternative electric suppliers, and customers of alternative electric suppliers and the utility under consideration. The commission shall provide notice to the public of the single capacity charge as determined for each territory. No new capacity charge is required to be paid before June 1, 2018. The capacity charge must be applied to alternative electric load that is not exempt as set forth under subsections (6) and (7). . . . In order to ensure that noncapacity electric generation services are not included in the capacity charge, in determining the capacity charge, the commission shall do both of the following and ensure that the resulting capacity charge does not differ for full service load and alternative electric supplier load:
>
> (a) For the applicable term of the capacity charge, include the capacity-related generation costs included in the utility's base rates, surcharges, and power supply cost recovery factors, regardless of whether those costs result from utility ownership of the capacity resources or the purchase or lease of the capacity resource from a third party.
>
> (b) For the applicable term of the capacity charge, subtract all non-capacity-related electric generation costs, including, but not limited to, costs previously set for recovery through net stranded cost recovery and securitization and the projected revenues, net of projected fuel costs, from all of the following:
>
> (i) All energy market sales.
>
> (ii) Off-system energy sales.
>
> (iii) Ancillary services sales.
>
> (iv) Energy sales under unit-specific bilateral contracts.

Q. What is specified in MCL 460.11 concerning the establishment of electric rates based on the cost of providing service?

A. MCL 460.11 states as follows:

> Establishment of electric rates; establishment of eligible low-income customer or senior citizen customer rates; public and private schools, universities, and community colleges rate schedules.
>
> Sec. 11.
> (1) Except as otherwise provided in this subsection, the commission shall ensure the establishment of electric rates equal to the cost of providing service to each customer class. In establishing cost of service rates, the commission shall ensure that each class, or sub-class, is assessed for its fair and equitable use of the electric grid. If the commission determines that the impact of imposing cost of service rates on customers of an electric utility would have a material impact on customer rates, the commission may approve an order that implements those rates over a suitable number of years. The commission shall ensure that the cost of providing service to each customer class is based on the allocation of production-related costs based on using the 75-0-25 method of cost allocation and transmission costs based on using the 100% demand method of cost allocation. The commission may modify this method if it determines that this method of cost allocation does not ensure that rates are equal to the cost of service.

Q. Have you prepared an exhibit in support of your testimony?

A. Yes. I have prepared the following exhibits.

- Exhibit EM-8 (RCS-2) presents my calculation of the State Reliability Mechanism capacity cost rate.
- Exhibit EM-9 (RCS-3) presents selected pages from DTE's SEC Form 10-K for 2016 showing capacity resources.
- Exhibit EM-10 (RCS-4) presents copies of selected documentation referenced in my testimony, including copies of some of the Company’s responses to data requests.

Q. Were the exhibits prepared by your or under your supervision?

A. Yes, they were.

II. STATE RELIABILITY MECHANISM CAPACITY COST RATE

Q. Is another witness for Energy Michigan presenting a comprehensive solution for the State Reliability Mechanism ("SRM") capacity cost rate and related matters?

A. Yes. Energy Michigan witness Alexander Zakem is presenting a comprehensive solution for the SRM capacity charge rate and related matters based on several important capacity resource concepts as utilized by MISO, which he discusses. Because Energy Michigan's SRM capacity charge proposal is presented by Mr. Zakem, the calculation that follows, which attempts to apply the formula in MCL 460.6w(3) to DTE's embedded capacity costs, is not the method advocated by Energy Michigan, nor does the resulting charge represent Energy Michigan's proposed SRM charge. Rather, my calculation addresses how the SRM charge should be calculated if the Commission decides to use a traditional, historic, embedded cost of service methodology.

Q. Ideally, how should the cost of new capacity resources be determined?

A. It is important to recognize that the capacity cost of a resource is not the total cost. The total cost of a generation supply resource may be much larger than the capacity cost in order to gain benefits such as lower fuel costs, reliability, to address emissions and environmental concerns, etc. MISO, with the approval of the FERC has determined that the cost of new capacity is represented by the Cost of New Entry ("CONE"). This is an annualized cost of a combustion turbine, without subtraction for sales of capacity, energy, or ancillary services. The CONE is determined by MISO by zone, and is updated every year in MISO filings with the FERC. Calculation of the CONE is governed by the MISO

Tariff.[1] At present, CONE in MISO Zone 7, which covers the DTE Electric and Consumers service territories in lower Michigan, is $94,900 per MW per year.[2] For new capacity resources, the CONE provides an objective frame of reference for the cost.

Q. How is the remainder of your testimony organized?

A. The remainder of my testimony addresses the determination of the State Reliability Mechanism capacity cost rate using DTE's embedded costs and reflecting the subtractions that are required by MCL 460.6w(3)(b) which were provided to me by Mr. Jennings of EVA. My testimony concerning this is organized into the following sections:

A. Capacity Costs
B. The 75-0-25 Production Cost Allocator
C. Energy Market Sales, Off-System Energy Sales, and Ancillary Service Revenue
D. Net Capacity Cost
E. DTE's Owned and Purchased Capacity in MW
F. Calculation of the State Reliability Mechanism Capacity Rate

A. <u>Capacity Costs</u>

Q. What does Act 341 require for the determination of capacity costs?

A. Act 341 at MCL 460.6w(3)(a) requires that:

> For the applicable term of the capacity charge, include the capacity-related generation costs included in the utility's base rates, surcharges, and power supply cost recovery factors, regardless of whether those costs result from utility ownership of the capacity resources or the purchase or lease of the capacity resource from a third party.

Q. What amount of capacity cost has DTE identified in the current docket?

A. In Case No. 18248 (the current proceeding), DTE has identified a capacity revenue

[1] See, e.g., MISO Tariff, Module E-1, section 69A.8, FERC Docket No. ER16-2662, filing dated September 23, 2016, Attachment B.
[2] Id.

requirement of $1,725,790,436 in total.[3]

Q. What amount of capacity cost did you start with for your calculations?

A. As shown on Exhibit EM-8 (RCS-2), I started with the Company-identified total capacity cost amount of $1.726 billion from DTE Exhibit __A-14. This includes the capacity-related generation costs that were included in the utility's base rates, surcharges, and power supply cost recovery factors, regardless of whether those costs result from utility ownership of the capacity resources or the purchase or lease of the capacity resource from a third party.

B. <u>The 75-0-25 Production Cost Allocator</u>

Q. What is the 75-0-25 Production Cost Allocator?

A. The 75-0-25 Production Cost Allocator has been utilized by the Commission for the allocation of electric utility production costs in traditional, historical, embedded cost of service studies. It has been utilized in the most recent fully litigated rate case application of DTE Electric Company, Case No. U-18014. Act 341, which was signed into law on December 20, 2016 and became effective on April 20, 2017, creates a presumption in favor of the 75-0-25 allocation method. Under the 75-0-25 Production Cost Allocator, 75 percent of the cost is treated as demand-related (i.e., as capacity cost), zero percent as on-peak energy, and 25 percent as total energy production cost.

Q. What does DTE witness Lacey state with respect to Company Exhibit A-13?

A. DTE witness Lacey states at page 4 of his testimony that Company Exhibit A-13,

[3] See, e.g., DTE Exhibit __A-14.

Schedule 1 contains the cost of service study ("COSS") for production costs approved in the Commission's January 3, 2017 order in Case No. U-18014, as prepared by the Commission Staff. Exhibit A-13, Schedule 2 is Power Supply Expenses calculation (Exhibit A10, Schedule C4 from Case No. U-18014) which underlies the production COSS approved in the Commission's January 31, 2017 order in Case No. U-18014.

Q. How was the allocation of production costs addressed in DTE's most recent rate case?

A. In the most recent fully litigated rate case application of DTE Electric Company, Case No. U-18014, the Production Cost Allocation was addressed at pages 96-101 of the Commission's January 31, 2017 Order. At page 100 of that Order, the Commission states that:

> [The] Commission acknowledges that new capacity will be needed to avoid future shortfalls; however, the Commission finds that a change to the production cost allocation method to 4CP 100 is not adequately refined to have a substantial impact on capacity issues.
>
> Additionally, the Commission reiterates that DTE Electric's production system was not designed and built simply to meet demand. Instead, the "company developed its production plant to both deliver energy and provide capacity at the lowest overall cost to all customers who use the system." June 15, 2015 order in Case No. U-17689, (June 15 order) pp. 21-22. Because DTE Electric's generating system still includes a mix of base load, intermediate, and peaking plants, the Commission reaffirms that the 4CP 75-0-25 production cost allocation method better recognizes the value of capacity in the company's system.

In DTE's most recent electric rate case, Case No. U-18014, the Commission rejected various parties' proposals to modify the 75-0-25 method.

Q. Was the allocation of production costs also addressed by the Commission in its

recent Order in the Consumers Energy Company rate case?

A. Yes. In the most recent fully litigated rate case application of Consumers Energy Company, Case No. U-17990, the Production Cost Allocation was addressed at pages 125-129 of the Commission's February 28, 2017 Order. At page 128 of that Order, the Commission notes that in P.A. 341 of 2016, the Michigan Legislature revised MCL 460-11(1) to create a presumption in favor of the 75-0-25 allocation method. The Commission noted that the new law states that:

> The commission shall ensure that the cost of providing service to each customer class is based on the allocation of production-related costs based on using the 75-0-25 method of cost allocation and transmission costs based on using the 100% demand method of cost allocation. The commission may modify this method if it determines that this method of cost allocation does not ensure that rates are equal to the cost of service.

In Consumers' most recent electric rate case, Case No. U-17990, the Commission thus also rejected various parties' proposals to modify the 75-0-25 method.

Q. How should the 75-0-25 Production Cost Allocation be applied in determining the capacity cost rate?

A. As noted above, under a traditional historical embedded cost of service method, as used in Case No. U-18014, the allocation of the Company's production costs should be based on treating 75% of the cost as demand, zero percent as on-peak energy, and 25% as total energy production cost.

Q. How do the Company witnesses address what capacity costs DTE used to develop its proposed State Reliability Mechanism capacity charge rate?

A. DTE witness Holmes at page 5 of her Direct Testimony indicates that the Company's proposed power supply rates is the functionalized power supply COSS supported by Company witness Lacey in Company Exhibit A-14. At page 4, Ms. Holmes also states that this is the same method of allocation used by both the Company and the MPSC Staff in developing power rates in DTE's most recent rate case, Case No. U-18014. At pages 6-7 of his Direct Testimony, Company witness Bloch states that:

> The basis for the proposed power supply rates in this case is the same functionalized power supply cost of service study approved by the Commission and used to set final rates in Case No. U-18014. Using this cost of service study, Company Witness Mr. Lacey determined the capacity revenue requirement for each cost of service class, which is shown on line 6 in his Exhibit A-14. Capacity rates for each primary rate class were determined by calculating the non-capacity rate for each class on a $/kWh basis and then subtracting the non-capacity rate from the current power supply energy rates to determine the capacity related energy charges. The non-capacity rate is calculated by subtracting the capacity revenue requirement on line 6 of Exhibit A-14 from the total power supply revenue requirement for the class, shown on line 1 of Exhibit A-14, to determine the non-capacity revenue requirement and then dividing the result by the power supply sales. All power supply revenue related to demand based charges are considered to be capacity related. Voltage level discounts were prorated based on the proposed capacity and non-capacity energy charges.

Q. For the purpose of determining the capacity charge under MCL 460.6w if using a traditional historical embedded cost of service approach, how should the cost of service requirement stated in MCL 460.11 be applied?

A. Under a traditional historical embedded cost of service approach, 75% of the embedded production cost would be treated as demand related, zero percent as on-peak energy related, and 25% as total energy related. These percentages would be used to allocate embedded costs to full service customer classes.

Q. Does it appear that DTE has applied the 75-0-25 Production Cost Allocation in its

presentation of capacity costs?

A. Yes, it does. By allocating production costs consistent with the Commission's final Order in Case No. U-18014, and as reflected in DTE's response to ABDE-1.2 wherein DTE provided its COSS in Excel, it appears that DTE has applied the 75-0-25 Production Cost Allocation in its presentation of capacity costs. If applied correctly, this would have effectively allocated to full service customer classes 75 percent of the Production Costs based on demand (capacity) and 25 percent based energy. Discovery has been asked by Energy Michigan of DTE concerning the application by the Company of the 75-0-25 Production Cost Allocation.

C. <u>Energy Market Sales Revenue, Off-System Energy Sales Revenue, and Ancillary Service Revenue, Net of Related Fuel Costs</u>

Q. What is required by Act 341 for the Energy Sales Margin and Ancillary Service Revenue?

A. Act 341 at MCL 460.6w(3)(b) states that:

> (b) For the applicable term of the capacity charge, subtract all non-capacity-related electric generation costs, including, but not limited to, costs previously set for recovery through net stranded cost recovery and securitization **and the projected revenues, net of projected fuel costs, from all of the following:**
>
> **(i) All energy market sales.**
> **(ii) Off-system energy sales.**
> **(iii) Ancillary services sales.**
> **(iv) Energy sales under unit-specific bilateral contracts.**
>
> (Emphasis supplied.)

Q. Did you receive amounts for those projected revenues and net projected fuel costs from another consultant?

A. Yes. I received amounts for the following elements that are specified under MCL 460.6w(3)(b) from Mr. Rupert ("Rob") Jennings of EVA. Mr. Jennings provided me with his forecasted amounts for each of these items for years 2017 through 2020: (i) energy market sales, (ii) off-system energy sales, (iii) ancillary services sales, and (iv) energy sales under unit-specific bilateral contracts.[4]

In addition, Mr. Jennings provided his estimates of related projected fuel costs for the years 2017 through 2020.

Q. How did you utilize the amounts provided to you by Mr. Jennings in your calculation of the SRM capacity charge?

A. For purposes of my calculation, I used the forecast amounts provided by Mr. Jennings for 2018. This corresponds with when the SRM capacity charge would commence. This is shown on Exhibit EM-8 (RCS-2), lines 4 through 10.

D. <u>Net Capacity Cost</u>

Q. What amount of net capacity cost did you determine?

A. As shown on Exhibit EM-8 (RCS-2), line 11, the net amount of capacity cost is $1.186 billion. From DTE’s total capacity cost of $1.726 billion, I added back the Company’s estimate of projected energy sales revenue net of fuel costs. This was added back because the forecasted energy sales revenue from DTE’s capacity is being provided by Energy Michigan witness Jennings. I then subtracted the 2018 net energy sales and ancillary services revenue less fuel costs provided to me by Energy Michigan witness

[4] DTE did not have any bilateral energy sales.

Jennings of $584 million.

E. ***DTE's Owned and Purchased Capacity in MW***

Q. What level of owned and purchased capacity has DTE reported?

A. DTE's generation capacity is a measure of the maximum electric output that DTE has available to meet peak load requirements. DTE's 2016 SEC form 10-K at page 8 reports that the Company had total supply of 12,158 MW.[5] This consists of owned generation having capacity of 11,669 MW and purchased and interchange power having capacity of 489 MW.

Q. What plant retirements are projected by DTE for each year, 2017 through 2020?

A. The Company's response to data request EMDE-2.12 indicates that DTE projects to retire River Rouge Unit 3 in 2020.

F. ***Calculation of the State Reliability Mechanism Capacity Rate***

Q. Please explain how you utilized the information previously discussed to compute the SRM capacity rate.

A. As shown on Exhibit EM-8 (RCS-2), if the SRM capacity rate were to be based on the Company's embedded costs for capacity less the revenue less fuel cost, dividing $1.186 billion of net capacity cost by the 12,158 MW of capacity produces a cost of $97,527 per MW-Year.

As also shown on Exhibit EM-8 (RCS-2), the SRM capacity cost rate that would be

[5] A copy of the cover and the cited pages of DTE's SEC Form 10-K for 2016 is included in Exhibit EM-9 (RCS-3).

charged to Alternative Energy Suppliers is $267.20 per MW-day.

Q. In order to develop an SRM capacity charge, is it necessary to have a breakout by rate classes as DTE is presenting?

A. No. An SRM capacity charge based on embedded costs can be developed on a $/MW-Year or $/MW-Day basis. If need be, a rate could presumably be developed by rate class by applying applicable line loss factors. It is believed that most if not all energy choice customers would be in the Secondary and Primary rate classes. Energy Michigan has asked discovery of DTE to ascertain the loss factors applicable to those classes, and to each rate within those classes where DTE ROA sales would occur.[6]

G. <u>Summary of Recommendation for SRM Capacity Rate</u>

Q. Please summarize your recommendation for an SRM Capacity Rate.

A. As shown on Exhibit EM-8 (RCS-2), I started with DTE's total capacity cost of $1.726 billion and added back DTE's projected energy sales revenue net of fuel cost amount of $44 million. DTE is projected to have $1.385 billion of energy market, off-system energy sales and ancillary service revenue. Net of related fuel costs of $801 million, the amount of net revenue less fuel costs is $584 million. The net capacity cost, determined by subtracting the $584 million net revenue amount from the $1.770 billion total capacity cost is $1.186 million. Dividing the $1.186 million by DTE's owned and purchased capacity of 12,158 MW produces an SRM capacity rate of $97,527 per MW-Year as shown on Exhibit EM-8 (RCS-2), line 14. The SRM capacity rate can also be stated as $267.20 per MW-Day, as shown on Exhibit EM-8 (RCS-2), line 15. As I previously

[6] The abbreviation "ROA" refers to Retail Open Access customer load.

noted, an SRM capacity rate of $267.20 per MW-Day results from a method based on traditional historical embedded costs of service methods. DTE Electric has proposed such a method, and my analysis preceding shows how it should be calculated. Again, such an approach is not being recommended by Energy Michigan, and the reader is referred to witness Zakem's Prefiled Direct Testimony in this matter in order to find Energy Michigan's recommended methodology and rate.

Q. If the Commission decides that the SRM charge should be based on the historical embedded cost of DTE's capacity without regard to incremental resources or incremental costs or Energy Michigan's proposal, what is your recommendation?

A. In that situation, I would recommend that my calculation herein of $267.20 per MW-day be used in place of DTE's proposal. As discussed, my calculation accurately represents the subtraction of various sales factors that are specified in PA 341.

Q. Does this complete your pre-filed direct testimony?

A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

****

In the matter, on the Commission's own motion,	)	
to open a docket to implement the provisions of	)	
Section 6w of 2016 PA 341 for	)	**Case No. U-18248**
DTE ELECTRIC COMPANY'S	)	
service territory.	)	
______________________________________	)	

EXHIBITS OF

RALPH C. SMITH

ON BEHALF OF

ENERGY MICHIGAN, INC.

QUALIFICATIONS OF RALPH C. SMITH

Accomplishments

Mr. Smith's professional credentials include being a Certified Financial Planner™ professional, a Certified Rate of Return Analyst, a licensed Certified Public Accountant and attorney. He functions as project manager on consulting projects involving utility regulation, regulatory policy and ratemaking and utility management. His involvement in public utility regulation has included project management and in-depth analyses of numerous issues involving telephone, electric, gas, and water and sewer utilities.

Mr. Smith has performed work in the field of utility regulation on behalf of industry, public service commission staffs, state attorney generals, municipalities, and consumer groups concerning regulatory matters before regulatory agencies in Alabama, Alaska, Arizona, Arkansas, California, Connecticut, Delaware, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Louisiana, Maine, Maryland, Massachusetts, Michigan, Minnesota, Mississippi, Missouri, New Jersey, New Mexico, New York, Nevada, North Carolina, North Dakota, Ohio, Oregon, Pennsylvania, South Carolina, South Dakota, Tennessee, Texas, Utah, Vermont, Virginia, Washington, Washington DC, West Virginia, Canada, Federal Energy Regulatory Commission and various state and federal courts of law. He has presented expert testimony in regulatory hearings on behalf of utility commission staffs and intervenors on several occasions.

Project manager in Larkin & Associates' review, on behalf of the Georgia Commission Staff, of the budget and planning activities of Georgia Power Company; supervised 13 professionals; coordinated over 200 interviews with Company budget center managers and executives; organized and edited voluminous audit report; presented testimony before the Commission. Functional areas covered included fossil plant O&M, headquarters and district operations, internal audit, legal, affiliated transactions, and responsibility reporting. All of our findings and recommendations were accepted by the Commission.

Key team member in the firm's management audit of the Anchorage Water and Wastewater Utility on behalf of the Alaska Commission Staff, which assessed the effectiveness of the Utility's operations in several areas; responsible for in-depth investigation and report writing in areas involving information systems, finance and accounting, affiliated relationships and transactions, and use of outside contractors. Testified before the Alaska Commission concerning certain areas of the audit report. AWWU concurred with each of Mr. Smith's 40 plus recommendations for improvement.

Co-consultant in the analysis of the issues surrounding gas transportation performed for the law firm of Cravath, Swaine & Moore in conjunction with the case of Reynolds Metals Co. vs. the Columbia Gas System, Inc.; drafted in-depth report concerning the regulatory treatment at both state and federal levels of issues such as flexible pricing and mandatory gas transportation.

Lead consultant and expert witness in the analysis of the rate increase request of the City of Austin - Electric Utility on behalf of the residential consumers. Among the numerous ratemaking issues addressed were the economies of the Utility's employment of outside services; provided both written and oral testimony outlining recommendations and their bases. Most of Mr. Smith's recommendations were adopted by the City Council and Utility in a settlement.

Key team member performing an analysis of the rate stabilization plan submitted by the Southern Bell Telephone & Telegraph Company to the Florida PSC; performed comprehensive analysis of the Company's projections and budgets which were used as the basis for establishing rates.

Lead consultant in analyzing Southwestern Bell Telephone separations in Missouri; sponsored the complex technical analysis and calculations upon which the firm's testimony in that case was based. He has also assisted in analyzing changes in depreciation methodology for setting telephone rates.

Lead consultant in the review of gas cost recovery reconciliation applications of Michigan Gas Utilities Company, Michigan Consolidated Gas Company, and Consumers Power Company. Drafted recommendations regarding the appropriate rate of interest to be applied to any over or under collections and the proper procedures and allocation methodology to be used to distribute any refunds to customer classes.

Lead consultant in the review of Consumers Power Company's gas cost recovery refund plan. Addressed appropriate interest rate and compounding procedures and proper allocation methodology.

Project manager in the review of the request by Central Maine Power Company for an increase in rates. The major area addressed was the propriety of the Company's ratemaking attrition adjustment in relation to its corporate budgets and projections.

Project manager in an engagement designed to address the impacts of the Tax Reform Act of 1986 on gas distribution utility operations of the Northern States Power Company. Analyzed the reduction in the corporate tax rate, uncollectibles reserve, ACRS, unbilled revenues, customer advances, CIAC, and timing of TRA-related impacts associated with the Company's tax liability.

Project manager and expert witness in the determination of the impacts of the Tax Reform Act of 1986 on the operations of Connecticut Natural Gas Company on behalf of the Connecticut Department of Public Utility Control - Prosecutorial Division, Connecticut Attorney General, and Connecticut Department of Consumer Counsel.

Lead Consultant for The Minnesota Department of Public Service ("DPS") to review the Minnesota Incentive Plan ("Incentive Plan") proposal presented by Northwestern Bell Telephone Company ("NWB") doing business as U S West Communications ("USWC"). Objective was to express an opinion as to whether current rates addressed by the plan were appropriate from a Minnesota intrastate revenue requirements and accounting perspective, and to assist in developing recommended modifications to NWB's proposed Plan.

Performed a variety of analytical and review tasks related to our work effort on this project. Obtained and reviewed data and performed other procedures as necessary (1) to obtain an understanding of the Company's Incentive Plan filing package as it relates to rate base, operating income, revenue requirements, and plan operation, and (2) to formulate an opinion concerning the reasonableness of current rates and of amounts included within the Company's Incentive Plan filing. These procedures included requesting and reviewing extensive discovery, visiting the Company's offices to review data, issuing follow-up information requests in many instances, telephone and on-site discussions with Company representatives, and frequent discussions with counsel and DPS Staff assigned to the project.

Lead Consultant in the regulatory analysis of Jersey Central Power & Light Company for the Department of the Public Advocate, Division of Rate Counsel. Tasks performed included on-site review and audit of Company, identification and analysis of specific issues, preparation of data requests, testimony, and cross examination questions. Testified in Hearings.

Assisted the NARUC Committee on Management Analysis with drafting the Consultant Standards for Management Audits.

Presented training seminars covering public utility accounting, tax reform, ratemaking, affiliated transaction auditing, rate case management, and regulatory policy in Maine, Georgia, Kentucky, and Pennsylvania. Seminars were presented to commission staffs and consumer interest groups.

Previous Positions

With Larkin, Chapski and Co., the predecessor firm to Larkin & Associates, was involved primarily in utility regulatory consulting, and also in tax planning and tax research for businesses and individuals, tax return preparation and review, and independent audit, review and preparation of financial statements.

Installed computerized accounting system for a realty management firm.

Education

Bachelor of Science in Administration in Accounting, with distinction, University of Michigan, Dearborn, 1979.

Master of Science in Taxation, Walsh College, Michigan, 1981. Master's thesis dealt with investment tax credit and property tax on various assets.

Juris Doctor, cum laude, Wayne State University Law School, Detroit, Michigan, 1986. Recipient of American Jurisprudence Award for academic excellence.

Continuing education required to maintain CPA license and CFP® certificate.

Passed all parts of CPA examination in first sitting, 1979. Received CPA certificate in 1981 and Certified Financial Planning certificate in 1983. Admitted to Michigan and Federal bars in 1986.

Michigan Bar Association.

American Bar Association, sections on public utility law and taxation.

Partial list of utility cases participated in:

79-228-EL-FAC	Cincinnati Gas & Electric Company (Ohio PUC)
79-231-EL-FAC	Cleveland Electric Illuminating Company (Ohio PUC)
79-535-EL-AIR	East Ohio Gas Company (Ohio PUC)
80-235-EL-FAC	Ohio Edison Company (Ohio PUC)
80-240-EL-FAC	Cleveland Electric Illuminating Company (Ohio PUC)
U-1933*	Tucson Electric Power Company (Arizona Corp. Commission)
U-6794	Michigan Consolidated Gas Co. --16 Refunds (Michigan PSC)
81-0035TP	Southern Bell Telephone Company (Florida PSC)
81-0095TP	General Telephone Company of Florida (Florida PSC)
81-308-EL-EFC	Dayton Power & Light Co.- Fuel Adjustment Clause (Ohio PUC)
810136-EU	Gulf Power Company (Florida PSC)
GR-81-342	Northern States Power Co. -- E-002/Minnesota (Minnesota PUC)
Tr-81-208	Southwestern Bell Telephone Company (Missouri PSC))
U-6949	Detroit Edison Company (Michigan PSC)
8400	East Kentucky Power Cooperative, Inc. (Kentucky PSC)
18328	Alabama Gas Corporation (Alabama PSC)
18416	Alabama Power Company (Alabama PSC)
820100-EU	Florida Power Corporation (Florida PSC)
8624	Kentucky Utilities (Kentucky PSC)
8648	East Kentucky Power Cooperative, Inc. (Kentucky PSC)
U-7236	Detroit Edison - Burlington Northern Refund (Michigan PSC)
U6633-R	Detroit Edison - MRCS Program (Michigan PSC)
U-6797-R	Consumers Power Company -MRCS Program (Michigan PSC)
U-5510-R	Consumers Power Company - Energy conservation Finance Program (Michigan PSC)
82-240E	South Carolina Electric & Gas Company (South Carolina PSC)
7350	Generic Working Capital Hearing (Michigan PSC)
RH-1-83	Westcoast Transmission Co., (National Energy Board of Canada)
820294-TP	Southern Bell Telephone & Telegraph Co. (Florida PSC)
82-165-EL-EFC (Subfile A)	Toledo Edison Company(Ohio PUC)
82-168-EL-EFC	Cleveland Electric Illuminating Company (Ohio PUC)
830012-EU	Tampa Electric Company (Florida PSC)
U-7065	The Detroit Edison Company - Fermi II (Michigan PSC)
8738	Columbia Gas of Kentucky, Inc. (Kentucky PSC)
ER-83-206	Arkansas Power & Light Company (Missouri PSC)
U-4758	The Detroit Edison Company – Refunds (Michigan PSC)
8836	Kentucky American Water Company (Kentucky PSC)
8839	Western Kentucky Gas Company (Kentucky PSC)
83-07-15	Connecticut Light & Power Co. (Connecticut DPU)
81-0485-WS	Palm Coast Utility Corporation (Florida PSC)
U-7650	Consumers Power Co. (Michigan PSC)
83-662	Continental Telephone Company of California, (Nevada PSC)
U-6488-R	Detroit Edison Co., FAC & PIPAC Reconciliation (Michigan PSC)
U-15684	Louisiana Power & Light Company (Louisiana PSC)
7395 & U-7397	Campaign Ballot Proposals (Michigan PSC)
820013-WS	Seacoast Utilities (Florida PSC)
U-7660	Detroit Edison Company (Michigan PSC)
83-1039	CP National Corporation (Nevada PSC)
U-7802	Michigan Gas Utilities Company (Michigan PSC)
83-1226	Sierra Pacific Power Company (Nevada PSC)
830465-EI	Florida Power & Light Company (Florida PSC)
U-7777	Michigan Consolidated Gas Company (Michigan PSC)
U-7779	Consumers Power Company (Michigan PSC)

U-7480-R	Michigan Consolidated Gas Company (Michigan PSC)
U-7488-R	Consumers Power Company – Gas (Michigan PSC)
U-7484-R	Michigan Gas Utilities Company (Michigan PSC)
U-7550-R	Detroit Edison Company (Michigan PSC)
U-7477-R**	Indiana & Michigan Electric Company (Michigan PSC)
18978	Continental Telephone Co. of the South Alabama (Alabama PSC)
R-842583	Duquesne Light Company (Pennsylvania PUC)
R-842740	Pennsylvania Power Company (Pennsylvania PUC)
850050-EI	Tampa Electric Company (Florida PSC)
16091	Louisiana Power & Light Company (Louisiana PSC)
19297	Continental Telephone Co. of the South Alabama (Alabama PSC)
76-18788AA &76-18793AA	Detroit Edison - Refund - Appeal of U-4807 (Ingham County, Michigan Circuit Court)
85-53476AA & 85-534785AA	Detroit Edison Refund - Appeal of U-4758 (Ingham County, Michigan Circuit Court)
U-8091/U-8239	Consumers Power Company - Gas Refunds (Michigan PSC)
TR-85-179**	United Telephone Company of Missouri (Missouri PSC)
85-212	Central Maine Power Company (Maine PSC)
ER-85646001 & ER-85647001	New England Power Company (FERC)
850782-EI & 850783-EI	Florida Power & Light Company (Florida PSC)
R-860378	Duquesne Light Company (Pennsylvania PUC)
R-850267	Pennsylvania Power Company (Pennsylvania PUC)
851007-WU & 840419-SU	Florida Cities Water Company (Florida PSC)
G-002/GR-86-160	Northern States Power Company (Minnesota PSC)
7195 (Interim)	Gulf States Utilities Company (Texas PUC)
87-01-03	Connecticut Natural Gas Company (Connecticut PUC))
87-01-02	Southern New England Telephone Company (Connecticut Department of Public Utility Control)
3673-	Georgia Power Company (Georgia PSC)
29484	Long Island Lighting Co. (New York Dept. of Public Service)
U-8924	Consumers Power Company – Gas (Michigan PSC)
Docket No. 1	Austin Electric Utility (City of Austin, Texas)
Docket E-2, Sub 527	Carolina Power & Light Company (North Carolina PUC)
870853	Pennsylvania Gas and Water Company (Pennsylvania PUC)
880069**	Southern Bell Telephone Company (Florida PSC)
U-1954-88-102 T E-1032-88-102	Citizens Utilities Rural Company, Inc. & Citizens Utilities Company, Kingman Telephone Division (Arizona CC)
89-0033	Illinois Bell Telephone Company (Illinois CC)
U-89-2688-T	Puget Sound Power & Light Company (Washington UTC))
R-891364	Philadelphia Electric Company (Pennsylvania PUC)
F.C. 889	Potomac Electric Power Company (District of Columbia PSC)
Case No. 88/546*	Niagara Mohawk Power Corporation, et al Plaintiffs, v. Gulf+Western, Inc. et al, defendants (Supreme Court County of Onondaga, State of New York)
87-11628*	Duquesne Light Company, et al, plaintiffs, against Gulf+ Western, Inc. et al, defendants (Court of the Common Pleas of Allegheny County, Pennsylvania Civil Division)
890319-EI	Florida Power & Light Company (Florida PSC)
891345-EI	Gulf Power Company (Florida PSC)
ER 8811 0912J	Jersey Central Power & Light Company (BPU)
6531	Hawaiian Electric Company (Hawaii PUCs)

R0901595	Equitable Gas Company (Pennsylvania Consumer Counsel)
90-10	Artesian Water Company (Delaware PSC)
89-12-05	Southern New England Telephone Company (Connecticut PUC)
900329-WS	Southern States Utilities, Inc. (Florida PSC)
90-12-018	Southern California Edison Company (California PUC)
90-E-1185	Long Island Lighting Company (New York DPS)
R-911966	Pennsylvania Gas & Water Company (Pennsylvania PUC)
I.90-07-037, Phase II	(Investigation of OPEBs) Department of the Navy and all Other Federal Executive Agencies (California PUC)
U-1551-90-322	Southwest Gas Corporation (Arizona CC)
U-1656-91-134	Sun City Water Company (Arizona RUCO)
U-2013-91-133	Havasu Water Company (Arizona RUCO)
91-174***	Central Maine Power Company (Department of the Navy and all Other Federal Executive Agencies)
U-1551-89-102 & U-1551-89-103	Southwest Gas Corporation - Rebuttal and PGA Audit (Arizona Corporation Commission)
Docket No. 6998	Hawaiian Electric Company (Hawaii PUC)
TC-91-040A and TC-91-040B	Intrastate Access Charge Methodology, Pool and Rates Local Exchange Carriers Association and South Dakota Independent Telephone Coalition
9911030-WS & 911-67-WS	General Development Utilities - Port Malabar and West Coast Divisions (Florida PSC)
922180	The Peoples Natural Gas Company (Pennsylvania PUC)
7233 and 7243	Hawaiian Nonpension Postretirement Benefits (Hawaiian PUC)
R-00922314 & M-920313C006	Metropolitan Edison Company (Pennsylvania PUC)
R00922428	Pennsylvania American Water Company (Pennsylvania PUC)
E-1032-92-083 & U-1656-92-183	Citizens Utilities Company, Agua Fria Water Division (Arizona Corporation Commission)
92-09-19	Southern New England Telephone Company (Connecticut PUC)
E-1032-92-073	Citizens Utilities Company (Electric Division), (Arizona CC)
UE-92-1262	Puget Sound Power and Light Company (Washington UTC))
92-345	Central Maine Power Company (Maine PUC)
R-932667	Pennsylvania Gas & Water Company (Pennsylvania PUC)
U-93-60**	Matanuska Telephone Association, Inc. (Alaska PUC)
U-93-50**	Anchorage Telephone Utility (Alaska PUC)
U-93-64	PTI Communications (Alaska PUC)
7700	Hawaiian Electric Company, Inc. (Hawaii PUC)
E-1032-93-111 & U-1032-93-193	Citizens Utilities Company - Gas Division (Arizona Corporation Commission)
R-00932670	Pennsylvania American Water Company (Pennsylvania PUC)
U-1514-93-169/ E-1032-93-169	Sale of Assets CC&N from Contel of the West, Inc. to Citizens Utilities Company (Arizona Corporation Commission)
7766	Hawaiian Electric Company, Inc. (Hawaii PUC)
93-2006- GA-AIR*	The East Ohio Gas Company (Ohio PUC)
94-E-0334	Consolidated Edison Company (New York DPS)
94-0270	Inter-State Water Company (Illinois Commerce Commission)
94-0097	Citizens Utilities Company, Kauai Electric Division (Hawaii PUC)
PU-314-94-688	Application for Transfer of Local Exchanges (North Dakota PSC)
94-12-005-Phase I	Pacific Gas & Electric Company (California PUC)
R-953297	UGI Utilities, Inc. - Gas Division (Pennsylvania PUC)
95-03-01	Southern New England Telephone Company (Connecticut PUC)
95-0342	Consumer Illinois Water, Kankakee Water District (Illinois CC)
94-996-EL-AIR	Ohio Power Company (Ohio PUC)
95-1000-E	South Carolina Electric & Gas Company (South Carolina PSC)

Non-Docketed Staff Investigation	Citizens Utility Company - Arizona Telephone Operations (Arizona Corporation Commission)
E-1032-95-473	Citizens Utility Co. - Northern Arizona Gas Division (Arizona CC)
E-1032-95-433	Citizens Utility Co. - Arizona Electric Division (Arizona CC)
	Collaborative Ratemaking Process Columbia Gas of Pennsylvania (Pennsylvania PUC)
GR-96-285	Missouri Gas Energy (Missouri PSC)
94-10-45	Southern New England Telephone Company (Connecticut PUC)
A.96-08-001 et al.	California Utilities' Applications to Identify Sunk Costs of Non-Nuclear Generation Assets, & Transition Costs for Electric Utility Restructuring, & Consolidated Proceedings (California PUC)
96-324	Bell Atlantic - Delaware, Inc. (Delaware PSC)
96-08-070, et al.	Pacific Gas & Electric Co., Southern California Edison Co. and San Diego Gas & Electric Company (California PUC)
97-05-12	Connecticut Light & Power (Connecticut PUC)
R-00973953	Application of PECO Energy Company for Approval of its Restructuring Plan Under Section 2806 of the Public Utility Code (Pennsylvania PUC)
97-65	Application of Delmarva Power &Light Co. for Application of a Cost Accounting Manual and a Code of Conduct (Delaware PSC)
16705	Entergy Gulf States, Inc. (Cities Steering Committee)
E-1072-97-067	Southwestern Telephone Co. (Arizona Corporation Commission)
Non-Docketed Staff Investigation	Delaware - Estimate Impact of Universal Services Issues (Delaware PSC)
PU-314-97-12	US West Communications, Inc. Cost Studies (North Dakota PSC)
97-0351	Consumer Illinois Water Company (Illinois CC)
97-8001	Investigation of Issues to be Considered as a Result of Restructuring of Electric Industry (Nevada PSC)
U-0000-94-165	Generic Docket to Consider Competition in the Provision of Retail Electric Service (Arizona Corporation Commission)
98-05-006-Phase I	San Diego Gas & Electric Co., Section 386 costs (California PUC)
9355-U	Georgia Power Company Rate Case (Georgia PUC)
97-12-020 - Phase I	Pacific Gas & Electric Company (California PUC)
U-98-56, U-98-60, U-98-65, U-98-67	Investigation of 1998 Intrastate Access charge filings (Alaska PUC)
(U-99-66, U-99-65, U-99-56, U-99-52)	Investigation of 1999 Intrastate Access Charge filing (Alaska PUC)
Phase II of 97-SCCC-149-GIT	Southwestern Bell Telephone Company Cost Studies (Kansas CC)
PU-314-97-465	US West Universal Service Cost Model (North Dakota PSC)
Non-docketed Assistance	Bell Atlantic - Delaware, Inc., Review of New Telecomm. and Tariff Filings (Delaware PSC)
Contract Dispute	City of Zeeland, MI - Water Contract with the City of Holland, MI (Before an arbitration panel)
Non-docketed Project	City of Danville, IL - Valuation of Water System (Danville, IL)
Non-docketed Project	Village of University Park, IL - Valuation of Water and Sewer System (Village of University Park, Illinois)

E-1032-95-417	Citizens Utility Co., Maricopa Water/Wastewater Companies et al. (Arizona Corporation Commission)
T-1051B-99-0497	Proposed Merger of the Parent Corporation of Qwest Communications Corporation, LCI International Telecom Corp., and US West Communications, Inc. (Arizona CC)
T-01051B-99-0105	US West Communications, Inc. Rate Case (Arizona CC)
A00-07-043	Pacific Gas & Electric - 2001 Attrition (California PUC)
T-01051B-99-0499	US West/Quest Broadband Asset Transfer (Arizona CC)
99-419/420	US West, Inc. Toll and Access Rebalancing (North Dakota PSC)
PU314-99-119	US West, Inc. Residential Rate Increase and Cost Study Review (North Dakota PSC
98-0252	Ameritech - Illinois, Review of Alternative Regulation Plan (Illinois CUB)
00-108	Delmarva Billing System Investigation (Delaware PSC)
U-00-28	Matanuska Telephone Association (Alaska PUC)
Non-Docketed	Management Audit and Market Power Mitigation Analysis of the Merged Gas System Operation of Pacific Enterprises and Enova Corporation (California PUC)
00-11-038	Southern California Edison (California PUC)
00-11-056	Pacific Gas & Electric (California PUC)
00-10-028	The Utility Reform Network for Modification of Resolution E-3527 (California PUC)
98-479	Delmarva Power & Light Application for Approval of its Electric and Fuel Adjustments Costs (Delaware PSC)
99-457	Delaware Electric Cooperative Restructuring Filing (Delaware PSC)
99-582	Delmarva Power & Light dba Conectiv Power Delivery Analysis of Code of Conduct and Cost Accounting Manual (Delaware PSC)
99-03-04	United Illuminating Company Recovery of Stranded Costs (Connecticut OCC)
99-03-36	Connecticut Light & Power (Connecticut OCC)
Civil Action No. 98-1117	West Penn Power Company vs. PA PUC (Pennsylvania PSC)
Case No. 12604	Upper Peninsula Power Company (Michigan AG)
Case No. 12613	Wisconsin Public Service Commission (Michigan AG)
41651	Northern Indiana Public Service Co Overearnings investigation (Indiana UCC)
13605-U	Savannah Electric & Power Company – FCR (Georgia PSC)
14000-U	Georgia Power Company Rate Case/M&S Review (Georgia PSC)
13196-U	Savannah Electric & Power Company Natural Gas Procurement and Risk Management/Hedging Proposal, Docket No. 13196-U (Georgia PSC)
Non-Docketed	Georgia Power Company & Savannah Electric & Power FPR Company Fuel Procurement Audit (Georgia PSC)
Non-Docketed	Transition Costs of Nevada Vertically Integrated Utilities (US Department of Navy)
Application No. 99-01-016, Phase I	Post-Transition Ratemaking Mechanisms for the Electric Industry Restructuring (US Department of Navy)
99-02-05	Connecticut Light & Power (Connecticut OCC)
01-05-19-RE03	Yankee Gas Service Application for a Rate Increase, Phase I-2002-IERM (Connecticut OCC)
G-01551A-00-0309	Southwest Gas Corporation, Application to amend its rate Schedules (Arizona CC)
00-07-043	Pacific Gas & Electric Company Attrition & Application for a rate increase (California PUC)

97-12-020 Phase II	Pacific Gas & Electric Company Rate Case (California PUC)
01-10-10	United Illuminating Company (Connecticut OCC)
13711-U	Georgia Power FCR (Georgia PSC)
02-001	Verizon Delaware § 271(Delaware DPA)
02-BLVT-377-AUD	Blue Valley Telephone Company Audit/General Rate Investigation (Kansas CC)
02-S&TT-390-AUD	S&T Telephone Cooperative Audit/General Rate Investigation (Kansas CC)
01-SFLT-879-AUD	Sunflower Telephone Company Inc., Audit/General Rate Investigation (Kansas CC)
01-BSTT-878-AUD	Bluestem Telephone Company, Inc. Audit/General Rate Investigation (Kansas CC)
P404, 407, 520, 413 426, 427, 430, 421/ CI-00-712	Sherburne County Rural Telephone Company, dba as Connections, Etc. (Minnesota DOC)
U-01-85	ACS of Alaska, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-34	ACS of Anchorage, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-83	ACS of Fairbanks, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-87	ACS of the Northland, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
96-324, Phase II	Verizon Delaware, Inc. UNE Rate Filing (Delaware PSC)
03-WHST-503-AUD	Wheat State Telephone Company (Kansas CC)
04-GNBT-130-AUD	Golden Belt Telephone Association (Kansas CC)
Docket 6914	Shoreham Telephone Company, Inc. (Vermont BPU)
Docket No. E-01345A-06-009	Arizona Public Service Company (Arizona Corporation Commission)
Case No. 05-1278-E-PC-PW-42T	Appalachian Power Company and Wheeling Power Company both d/b/a American Electric Power (West Virginia PSC)
Docket No. 04-0113	Hawaiian Electric Company (Hawaii PUC)
Case No. U-14347	Consumers Energy Company (Michigan PSC)
Case No. 05-725-EL-UNC	Cincinnati Gas & Electric Company (PUC of Ohio)
Docket No. 21229-U	Savannah Electric & Power Company (Georgia PSC)
Docket No. 19142-U	Georgia Power Company (Georgia PSC)
Docket No. 03-07-01RE01	Connecticut Light & Power Company (CT DPUC)
Docket No. 19042-U	Savannah Electric & Power Company (Georgia PSC)
Docket No. 2004-178-E	South Carolina Electric & Gas Company (South Carolina PSC)
Docket No. 03-07-02	Connecticut Light & Power Company (CT DPUC)
Docket No. EX02060363, Phases I&II	Rockland Electric Company (NJ BPU)
Docket No. U-00-88	ENSTAR Natural Gas Company and Alaska Pipeline Company (Regulatory Commission of Alaska)
Phase 1-2002 IERM, Docket No. U-02-075	Interior Telephone Company, Inc. (Regulatory Commission of Alaska)
Docket No. 05-SCNT- 1048-AUD	South Central Telephone Company (Kansas CC)
Docket No. 05-TRCT- 607-KSF	Tri-County Telephone Company (Kansas CC)
Docket No. 05-KOKT- 060-AUD	Kan Okla Telephone Company (Kansas CC)
Docket No. 2002-747	Northland Telephone Company of Maine (Maine PUC)

Docket No. 2003-34	Sidney Telephone Company (Maine PUC)
Docket No. 2003-35	Maine Telephone Company (Maine PUC)
Docket No. 2003-36	China Telephone Company (Maine PUC)
Docket No. 2003-37	Standish Telephone Company (Maine PUC)
Docket Nos. U-04-022, U-04-023	Anchorage Water and Wastewater Utility (Regulatory Commission of Alaska)
Case 05-116-U/06-055-U	Entergy Arkansas, Inc. EFC (Arkansas Public Service Commission)
Case 04-137-U	Southwest Power Pool RTO (Arkansas Public Service Commission)
Case No. 7109/7160	Vermont Gas Systems (Department of Public Service)
Case No. ER-2006-0315	Empire District Electric Company (Missouri PSC)
Case No. ER-2006-0314	Kansas City Power & Light Company (Missouri PSC)
Docket No. U-05-043,44	Golden Heart Utilities/College Park Utilities (Regulatory Commission of Alaska)
A-122250F5000	Equitable Resources, Inc. and The Peoples Natural Gas Company, d/b/a Dominion Peoples (Pennsylvania PUC)
E-01345A-05-0816	Arizona Public Service Company (Arizona CC)
Docket No. 05-304	Delmarva Power & Light Company (Delaware PSC)
05-806-EL-UNC	Cincinnati Gas & Electric Company (Ohio PUC)
U-06-45	Anchorage Water Utility (Regulatory Commission of Alaska)
03-93-EL-ATA, 06-1068-EL-UNC	Duke Energy Ohio (Ohio PUC)
PUE-2006-00065	Appalachian Power Company (Virginia Corporation Commission)
G-04204A-06-0463 et. al	UNS Gas, Inc. (Arizona CC)
U-06-134	Chugach Electric Association, Inc. (Regulatory Commission of Alaska)
Docket No. 2006-0386	Hawaiian Electric Company, Inc (Hawaii PUC)
E-01933A-07-0402	Tucson Electric Power Company (Arizona CC)
G-01551A-07-0504	Southwest Gas Corporation (Arizona CC)
Docket No.UE-072300	Puget Sound Energy, Inc. (Washington UTC)
PUE-2008-00009	Virginia-American Water Company (Virginia SCC)
PUE-2008-00046	Appalachian Power Company (Virginia SCC)
E-01345A-08-0172	Arizona Public Service Company (Arizona CC)
A-2008-2063737	Babcock & Brown Infrastructure Fund North America, LP. and The Peoples Natural Gas Company, d/b/a Dominion Peoples (Pennsylvania PUC)
08-1783-G-42T	Hope Gas, Inc., dba Dominion Hope (West Virginia PSC)
08-1761-G-PC	Hope Gas, Inc., dba Dominion Hope, Dominion Resources, Inc., and Peoples Hope Gas Companies (West Virginia PSC)
Docket No. 2008-0083	Hawaiian Electric Company, Inc. (Hawaii PUC)
Docket No. 2008-0266	Young Brothers, Limited (Hawaii PUC)
G-04024A-08-0571	UNS Gas, Inc. (Arizona CC)
Docket No. 09-29	Tidewater Utilities, Inc. (Delaware PSC)
Docket No. UE-090704	Puget Sound Energy, Inc. (Washington UTC)
09-0878-G-42T	Mountaineer Gas Company (West Virginia PSC)
2009-UA-0014	Mississippi Power Company (Mississippi PSC)
Docket No. 09-0319	Illinois-American Water Company (Illinois CC)
Docket No. 09-414	Delmarva Power & Light Company (Delaware PSC)
R-2009-2132019	Aqua Pennsylvania, Inc. (Pennsylvania PUC)
Docket Nos. U-09-069, U-09-070	ENSTAR Natural Gas Company (Regulatory Commission of Alaska)
Docket Nos. U-04-023, U-04-024	Anchorage Water and Wastewater Utility - Remand (Regulatory Commission of Alaska)
W-01303A-09-0343 & SW-01303A-09-0343	Arizona-American Water Company (Arizona CC)
09-872-EL-FAC & 09-873-EL-FAC	Financial Audits of the FAC of the Columbus Southern Power Company and the Ohio Power Company - Audit I (Ohio PUC)

2010-00036	Kentucky-American Water Company (Kentucky PSC)
E-04100A-09-0496	Southwest Transmission Cooperative, IHnc. (Arizona CC)
E-01773A-09-0472	Arizona Electric Power Cooperative, Inc. (Arizona CC)
R-2010-2166208, R-2010-2166210, R-2010-2166212, & R-2010-2166214	Pennsylvania-American Water Company (Pennsylvania PUC)
PSC Docket No. 09-0602	Central Illinois Light Company D/B/A AmerenCILCO; Central Illinois Public Service Company D/B/A AmerenCIPS; Illinois Power Company D/B/A AmerenIP (Illinois CC)
10-0713-E-PC	Allegheny Power and FirstEnergy Corp. (West Virginia PSC)
Docket No. 31958	Georgia Power Company (Georgia PSC)
Docket No. 10-0467	Commonwealth Edison Company (Illinois CC)
PSC Docket No. 10-237	Delmarva Power & Light Company (Delaware PSC)
U-10-51	Cook Inlet Natural Gas Storage Alaska, LLC (Regulatory Commission of Alaska)
10-0699-E-42T	Appalachian Power Company and Wheeling Power Company (West Virginia PSC)
10-0920-W-42T	West Virginia-American Water Company (West Virginia PSC)
A.10-07-007	California-American Water Company (California PUC)
A-2010-2210326	TWP Acquisition (Pennsylvania PUC)
09-1012-EL-FAC	Financial, Management, and Performance Audit of the FAC for Dayton Power and Light – Audit 1 (Ohio PUC)
10-268-EL FAC et al.	Financial Audit of the FAC of the Columbus Southern Power Company and the Ohio Power Company – Audit II (Ohio PUC)
Docket No. 2010-0080	Hawaiian Electric Company, Inc. (Hawaii PUC)
G-01551A-10-0458	Southwest Gas Corporation (Arizona CC)
10-KCPE-415-RTS	Kansas City Power & Light Company – Remand (Kansas CC)
PUE-2011-00037	Virginia Appalachian Power Company (Commonwealth of Virginia SCC)
R-2011-2232243	Pennsylvania-American Water (Pennsylvania PUC)
U-11-100	Power Purchase Agreement between Chugach Association, Inc. and Fire Island Wind, LLC (Regulatory Commission of Alaska)
A.10-12-005	San Diego Gas & Electric Company (California PUC)
PSC Docket No. 11-207	Artesian Water Company, Inc. (Delaware PSC)
Cause No. 44022	Indiana-American Water Company, Inc. (Indiana Utility Regulatory Commission)
PSC Docket No. 10-247	Management Audit of Tidewater Utilities, Inc. Affiliate Transactions (Delaware Public Service Commission)
G-04204A-11-0158	UNS Gas, Inc. (Arizona Corporation Commission)
E-01345A-11-0224	Arizona Public Service Company (Arizona CC)
UE-111048 & UE-111049	Puget Sound Energy, Inc. (Washington Utilities and Transportation Commission)
Docket No. 11-0721	Commonwealth Edison Company (Illinois CC)
11AL-947E	Public Service Company of Colorado (Colorado PSC)
U-11-77 & U-11-78	Golden Heart Utilities, Inc. and College Utilities Corporation (The Regulatory Commission of Alaska)
Docket No. 11-0767	Illinois-American Water Company (Illinois CC)
PSC Docket No. 11-397	Tidewater Utilities, Inc. (Delaware PSC)
Cause No. 44075	Indiana Michigan Power Company (Indiana Utility Regulatory Commission)
Docket No. 12-0001	Ameren Illinois Company (Illinois CC)
11-5730-EL-FAC	Financial, Management, and Performance Audit of the FAC for Dayton Power and Light – Audit 2 (Ohio PUC)
PSC Docket No. 11-528	Delmarva Power & Light Company (Delaware PSC)
11-281-EL-FAC et al.	Financial Audit of the FAC of the Columbus Southern Power Company and the Ohio Power Company – Audit III (Ohio PUC)

Cause No. 43114-IGCC-4S1	Duke Energy Indiana, Inc. (Indiana Utility Regulatory Commission)
Docket No. 12-0293	Ameren Illinois Company (Illinois CC)
Docket No. 12-0321	Commonwealth Edison Company (Illinois CC)
12-02019 & 12-04005	Southwest Gas Corporation (Public Utilities Commission of Nevada)
Docket No. 2012-218-E	South Carolina Electric & Gas (South Carolina PSC)
Docket No. E-72, Sub 479	Dominion North Carolina Power (North Carolina Utilities Commission)
12-0511 & 12-0512	North Shore Gas Company and The Peoples Gas Light and Coke Company (Illinois CC)
E-01933A-12-0291	Tucson Electric Power Company (Arizona CC)
Case No. 9311	Potomac Electric Power Company (Maryland PSC)
Cause No. 43114-IGCC-10	Duke Energy Indiana, Inc. (Indiana Utility Regulatory Commission)
Docket No. 36498	Georgia Power Company (Georgia PSC)
Case No. 9316	Columbia Gas of Maryland, Inc. (Maryland PSC)
Docket No. 13-0192	Ameren Illinois Company (Illinois CC)
12-1649-W-42T	West Virginia-American Water Company (West Virginia PSC)
E-04204A-12-0504	UNS Electric, Inc. (Arizona CC)
PUE-2013-00020	Virginia and Electric Power Company (Virginia SCC)
R-2013-2355276	Pennsylvania-American Water Company (Pennsylvania PUC)
Formal Case No. 1103	Potomac Electric Power Company (District of Columbia PSC)
U-13-007	Chugach Electric Association, Inc. (The Regulatory Commission of Alaska)
12-2881-EL-FAC	Financial, Management, and Performance Audit of the FAC for Dayton Power and Light – Audit 3 (Ohio PUC)
Docket No. 36989	Georgia Power Company (Georgia PSC)
Cause No. 43114-IGCC-11	Duke Energy Indiana, Inc. (Indiana Utility Regulatory Commission)
UM 1633	Investigation into Treatment of Pension Costs in Utility Rates (Oregon PUC)
13-1892-EL FAC	Financial Audit of the FAC and AER of the Ohio Power Company – Audit I (Ohio PUC)
14-255-EL RDR	Regulatory Compliance Audit of the 2013 DIR of Ohio Power Company (Ohio PUC)
U-14-001	Chugach Electric Association, Inc. (The Regulatory Commission of Alaska)
U-14-002	Alaska Power Company (The Regulatory Commission of Alaska)
PUE-2014-00026	Virginia Appalachian Power Company (Commonwealth of Virginia SCC)
14-0117-EL-FAC	Financial, Management, and Performance Audit of the FAC and Purchased Power Rider for Dayton Power and Light – Audit 1 (Ohio PUC)
14-0702-E-42T	Monongahela Power Company and The Potomac Edison Company (West Virginia PSC)
Formal Case No. 1119	Merger of Exelon Corporation, Pepco Holdings, Inc., Potomac Electric Power Company, Exelon Energy Delivery Company, LLC, and New Special Purpose Entity, LLC (District of Columbia PSC)
R-2014-2428742	West Penn Power Company (Pennsylvania PUC)
R-2014-2428743	Pennsylvania Electric Company (Pennsylvania PUC)
R-2014-2428744	Pennsylvania Power Company (Pennsylvania PUC)
R-2014-2428745	Metropolitan Edison Company (Pennsylvania PUC)
Cause No. 43114-IGCC-12/13	Duke Energy Indiana, Inc. (Indiana Utility Regulatory Commission)
14-1152-E-42T	Appalachian Power Company and Wheeling Power Company (West Virginia PSC)
WS-01303A-14-0010	EPCOR Water Arizona, Inc. (Arizona CC)
2014-000396	Kentucky Power Company (Kentucky PSC)
15-03-45[^]	Iberdrola, S.A. Et Al, and UIL Holdings Corporation merger (Connecticut PURA)
A.14-11-003	San Diego Gas & Electric Company (California PUC)
U-14-111	ENSTAR Natural Gas Company (Regulatory Commission of Alaska)
2015-UN-049	Atmos Energy Corporation (Mississippi PSC)
15-0003-G-42T	Mountaineer Gas Company (West Virginia PSC)

PUE-2015-00027	Virginia Electric and Power Company (Commonwealth of Virginia SCC)
Docket No. 2015-0022	Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc., Maui Electric Company Limited, and NextEra Energy, Inc. (Hawaii PUC)
15-0676-W-42T	West Virginia-American Water Company (West Virginia PSC)
15-07-38^^	Iberdrola, S.A. Et Al, and UIL Holdings Corporation merger (Connecticut PURA)
15-26^^	Iberdrola, S.A. Et Al, and UIL Holdings Corporation merger (Massachusetts DPU)
15-042-EL-FAC	Management/Performance and Financial Audit of the FAC and Purchased Power Rider for Dayton Power and Light (Ohio PUC)
2015-UN-0080	Mississippi Power Company (Mississippi PSC)
Docket No. 15-00042	B&W Pipeline, LLC (Tennessee Regulatory Authority)
WR-2015-0301/SR-2015 -0302	Missouri American Water Company (Missouri PSC)
U-15-089, U-15-091, & U-15-092	Golden Heart Utilities, Inc. and College Utilities Corporation (The Regulatory Commission of Alaska)
Docket No. 16-00001	Kingsport Power Company d/b/a AEP Appalachian Power (Tennessee Regulatory Authority)
PUE-2015-00097	Virginia-American Water Company (Commonwealth of Virginia SCC)
15-1854-EL-RDR	Management/Performance and Financial Audit of the Alternative Energy Recovery Rider of Duke Energy Ohio, Inc. (Ohio PUC)
P-15-014	PTE Pipeline LLC (Regulatory Commission of Alaska)
P-15-020	Swanson River Oil Pipeline, LLC (Regulatory Commission of Alaska)
Docket No. 40161	Georgia Power Company – Integrated Resource Plan (Georgia PSC)
Formal Case No. 1137	Washington Gas Light Company (District of Columbia PSC)
160021-EI, et al.	Florida Power Company (Florida PSC)
R-2016-2537349	Metropolitan Edison Company (Pennsylvania PUC)
R-2016-2537352	Pennsylvania Electric Company (Pennsylvania PUC)
R-2016-2537355	Pennsylvania Power Company (Pennsylvania PUC)
R-2016-2537359	West Penn Power Company (Pennsylvania PUC)
16-0717-G-390P	Hope Gas, Inc., dba Dominion Hope (West Virginia PSC)
15-1256-G-390P (Reopening)/16-0922-G-390P	Mountaineer Gas Company (West Virginia PSC)
16-0550-W-P	West Virginia-American Water Company (West Virginia PSC)
CEPR-AP-2015-0001	Puerto Rico Electric Power Authority (Puerto Rico Energy Commission)

* Testimony filed, examination not completed
** Issues stipulated
*** Company withdrew case
^ Testimony filed, case withdrawn after proposed decision issued
^^ Issues stipulated before testimony was filed

DTE Electric Company
State Reliability Mechanism Capacity Rate

(Millions of Dollars)

Line No.	Description	Total Amount (A)	Reference
1	Capacity Costs Per Company	$ 1,726	Note A
2	Add: Projected Energy Sales Revenue Net of Fuel Cost Per Company	$ 44	Note A
3	Adjusted DTE Capacity Costs	$ 1,770	
	Less:		
4	Energy Market Sales	$ (1,369)	Note B
5	Off-System Energy Sales	$ -	Note B
6	Ancillary Service Sales	$ (16)	Note B
7	Bilateral Energy Sales	$ -	Note B
8	Revenue	$ (1,385)	
9	Related Fuel Costs	$ 801	Note B
10	Net Revenue Less Fuel Costs	$ (584)	
11	Net Capacity Cost	$ 1,186	L1 + L8
12	Owned and Purchased Capacity in MW	12,158	Note C
13	SRM Capacity Annual Rate $ Million / MW-Year	$ 0.098	
14	SRM Capacity Annual Rate, $ / MW-Year	$ 97,527	

15 SRM Capacity Daily Rate, $ / MW-Day

$$\frac{\$1,185,739,000}{12,158 \;/\; 365} = \$\ 267.20 \text{ / MW-Day}$$

Notes and Source

[A]: Company Exhibit A-14

[B]: Energy Michigan witness Jennings, 2018 amounts

[C]: Company's 2016 SEC Form 10-K, pages 8

	Description	MW
16	Owned Generation	11,669
17	Long-Term Contracts for Renewable Power	489
18	Total Supply	12,158

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the Fiscal Year Ended December 31, 2016

Commission File Number	Registrants, State of Incorporation, Address, and Telephone Number	I.R.S. Employer Identification No.
1-11607	**DTE Energy Company** (a Michigan corporation) One Energy Plaza Detroit, Michigan 48226-1279 313-235-4000	38-3217752
1-2198	**DTE Electric Company** (a Michigan corporation) One Energy Plaza Detroit, Michigan 48226-1279 313-235-4000	38-0478650

Securities registered pursuant to Section 12(b) of the Act:

Registrant	Title of Each Class	Name of Exchange on which Registered
DTE Energy Company (DTE Energy)	Common stock, without par value	New York Stock Exchange
DTE Energy	2012 Series C 5.25% Junior Subordinated Debentures due 2062	New York Stock Exchange
DTE Energy	2016 Series B 5.375% Junior Subordinated Debentures due 2076	New York Stock Exchange
DTE Energy	2016 Series F 6.00% Junior Subordinated Debentures due 2076	New York Stock Exchange
DTE Energy	6.50% Corporate Units	New York Stock Exchange
DTE Electric Company (DTE Electric)	None	None

Securities registered pursuant to Section 12(g) of the Act:

DTE Energy None **DTE Electric** None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

DTE Energy **Yes** ☒ **No** ☐ **DTE Electric** **Yes** ☒ **No** ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

DTE Energy **Yes** ☐ **No** ☒ **DTE Electric** **Yes** ☐ **No** ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

DTE Energy **Yes** ☒ **No** ☐ **DTE Electric** **Yes** ☒ **No** ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

DTE Energy **Yes** ☒ **No** ☐ **DTE Electric** **Yes** ☒ **No** ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.

DTE Energy ☐ **DTE Electric** ☒

Weather, economic factors, competition, energy efficiency initiatives, and electricity prices affect sales levels to customers. DTE Electric's peak load and highest total system sales generally occur during the third quarter of the year, driven by air conditioning and other cooling-related demands. DTE Electric's operations are not dependent upon a limited number of customers, and the loss of any one or a few customers would not have a material adverse effect on the results of DTE Electric.

Fuel Supply and Purchased Power

DTE Electric's power is generated from a variety of fuels and is supplemented with purchased power. DTE Electric expects to have an adequate supply of fuel and purchased power to meet its obligation to serve customers. DTE Electric's generating capability is heavily dependent upon the availability of coal. Coal is purchased from various sources in different geographic areas under agreements that vary in both pricing and terms. DTE Electric expects to obtain the majority of its coal requirements through long-term contracts, with the balance to be obtained through short-term agreements and spot purchases. DTE Electric has long-term and short-term contracts for the purchase of approximately 28.0 million tons of low-sulfur western coal and approximately 2.3 million tons of Appalachian coal to be delivered from 2017 to 2021. All of these contracts have pricing schedules. DTE Electric has approximately 90% of the expected coal requirements for 2017 under contract. Given the geographic diversity of supply, DTE Electric believes it can meet its expected generation requirements. DTE Electric leases a fleet of rail cars and has the expected western and eastern coal rail requirements under contract through 2021. Contracts covering expected vessel transportation requirements for delivery of purchased coal to electric generating facilities are under contract through 2019.

DTE Electric participates in the energy market through MISO. DTE Electric offers its generation in the market on a day-ahead and real-time basis and bids for power in the market to serve its load. DTE Electric is a net purchaser of power that supplements its generation capability to meet customer demand during peak cycles or during major plant outages.

Properties

DTE Electric owns generating facilities that are located in the State of Michigan. Substantially all of DTE Electric's property is subject to the lien of a mortgage.

Generating facilities owned and in service as of December 31, 2016 are shown in the following table:

Facility	Location by Michigan County	Year in Service	Net Generation Capacity[(a)] (MW)
Fossil-fueled Steam-Electric			
Belle River[(b)]	St. Clair	1984 and 1985	1,034
Greenwood	St. Clair	1979	785
Monroe[(c)]	Monroe	1971, 1973, and 1974	3,066
River Rouge	Wayne	1958	272
St. Clair	St. Clair	1953, 1954, 1959, 1961, and 1969	1,367
Trenton Channel	Wayne	1968	520
			7,044
Natural gas and Oil-fueled Peaking Units	Various	1966-1971, 1981, 1999, 2002, and 2003	2,033
Nuclear-fueled Steam-Electric Fermi 2[(d)]	Monroe	1988	1,141
Hydroelectric Pumped Storage Ludington[(e)]	Mason	1973	985
Renewables[(f)]			
Wind			
Brookfield Wind Park	Huron	2014	75
Echo Wind Park	Huron	2014	112
Gratiot Wind Park	Gratiot	2011 and 2012	102
Pinnebog Wind Park	Huron	2016	51
Thumb Wind Project	Huron and Sanilac	2012	110
			450
Solar	Various	2010-2016	16
			11,669

____

(a) Represents summer net rating for all units with the exception of renewable facilities. The summer net rating is based on operating experience, the physical condition of units, environmental control limitations, and customer requirements for steam, which would otherwise be used for electric generation. Wind and solar facilities reflect name plate capacity.

(b) The Belle River capability represents DTE Electric’s entitlement to 81% of the capacity and energy of the plant. See Note 7 to the Consolidated Financial Statements in Item 8 of this Report, "Jointly-Owned Utility Plant."

(c) The Monroe generating plant provided 38% of DTE Electric’s total 2016 power plant generation.

(d) In December 2016, the NRC approved the extension of the operating license of Fermi 2 which permits the power plant to continue generating electricity until 2045. The original operating license for the plant would have expired in 2025.

(e) Represents DTE Electric’s 49% interest in Ludington with a total capability of 2,010 MW. See Note 7 to the Consolidated Financial Statements in Item 8 of this Report, "Jointly-Owned Utility Plant."

(f) In addition to the owned renewable facilities described above, DTE Electric has long-term contracts for 489 MW of renewable power generated from wind, solar, and biomass facilities.

See "Capital Investments" in Management's Discussion and Analysis in Item 7 of this Report for information regarding plant retirements and future capital expenditures.

MPSC Case No.: U-18248
Respondent: T. A. Bloch/T. W. Lacey/ K. A. Holmes / M. A. Williams
Requestor: ABATE-1
Question No.: ABDE-1.2
Page: 1 of 1

Question: If not otherwise included in response to the previous question, please provide the full Company cost of service study and rate design workpapers, with all linked documents and formulae and links intact, approved in Case No. U-18014.

Answer: The final cost of service and rate design approved in Case No. U-18014 was performed by MPSC Staff. See attached files named U-18248 ABDE-1.2 Final U-18014 Rate Design.xslx and U-18248 ABDE-1.2 U-18014 ORDERCOSS(FINAL).xslx .

MPSC Case No.: U-18248
Respondent: A. P. Wojtowicz
Requestor: EM-2
Question No.: EMDE-2.12
Page: 1 of 1

Question: Identify and explain any plant retirements that are forecast for each year, 2017 through 2020.

Answer: The Company is currently forecasting the retirement of River Rouge unit 3 in 2020.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

****

In the matter, on the Commission's own motion,	)	
to open a docket to implement the provisions of	)	
Section 6w of 2016 PA 341 for	)	**Case No. U-18248**
DTE ELECTRIC COMPANY'S	)	
service territory.	)	
______________________________________	)	

TESTIMONY & EXHIBITS OF

RUPERT R. ("ROB") JENNINGS

ON BEHALF OF

ENERGY MICHIGAN, INC.

DIRECT TESTIMONY OF RUPERT R. JENNINGS
TABLE OF CONTENTS

I. INTRODUCTION 2

II. ENERGY MARKET SALES 4

III. OFF-SYSTEM POWER SALES 8

IV. ANCILLARY SERVICES 9

V. BILATERAL ENERGY SALES 9

RUPERT R. JENNINGS (ROB)
DIRECT TESTIMONY

I. INTRODUCTION

Q. Please state your names and business address.

A. Rupert R. Jennings, 1901 N. Moore St. #1200, Arlington, Virginia 22209.

Q. What is your position?

A. I am a Senior Consultant focused on the electricity markets with Energy Ventures Analysis, Inc.

Q. Please describe Energy Ventures Analysis, Inc.

A. Energy Ventures Analysis, Inc. ("EVA") is a consulting firm that engages in a variety of projects for clients in both the public and private sectors related to energy and environmental issues. Much of our energy-related work is related to analysis of the electricity and fuel markets. Our clients in those areas include electric utilities, independent power producers, fuel producers and transporters, large energy consumers, industry groups, regulators, and agencies of the Federal and State governments. EVA also represents interveners in utility rate proceedings, and has filed testimony in both state and federal courts as well as before the Federal Energy Regulatory Commission ("FERC").

Q. Please summarize your education and professional backgrounds.

A. I joined EVA in 2013. I specialize in electric market modeling using AURORAxmp, an hourly dispatch model that EVA licenses from EPIS, Inc. I oversee the customization of modeling inputs to reflect greater granularity in the model assumptions and I am responsible for EVA's short- and long-term power and capacity outlooks. I also participate in customized consulting projects related to power markets. Prior to joining EVA, I was a Power Analyst at Pace Global, a Siemens Business. I hold a B.S. in Integrated Science and Technology from James Madison University with a concentration in Energy.

Q. On whose behalf are you appearing?

A. This testimony is filed on behalf of Energy Michigan, Inc. ("Energy Michigan").

Q. What is the purpose of your testimony?

A. EVA and Larkin & Associates, PLLC (“Larkin”) were engaged by Varnum LLP, counsel to Energy Michigan, to evaluate the capacity rate issues in DTE Electric Co.’s (“DTE”) Case No. U-18248 before the Michigan Public Service Commission (the “Commission”). The goal of the engagement was to develop and file a capacity charge ($ per MW-Day) consistent with the provisions of MCL 460.6w(3). The statute provides in subsection (3)(a) that the capacity charge may include the capacity-related generation costs included in the utility’s base rates, surcharges, and power supply cost recovery factors, less the non-capacity-related electric generation costs from all of the following (i) all energy market sales; (ii) off-system energy sales, (iii) ancillary service sales, and (iv) energy sales under unit-specific bilateral contracts, as set forth in subsection (3)(b). EVA’s specific scope was to forecast all items included in Section 3(b) which would then be utilized by Larkin to calculate a capacity charge.

Q. For what period is the forecast made?

A. For the period 2018 through 2021.

Q. Please describe the documents reviewed for this engagement.

A. EVA reviewed DTE’s filings, responses to discovery requests made by parties to this proceeding including Larkin and EVA, DTE’s filings to the Securities and Exchange Commission (“SEC”), DTE’s annual Form 1 filings to the FERC, and documents produced by the Midcontinent ISO (“MISO”).

Q. Did DTE provide all the information that you requested?

A. No. DTE did not provide some of the requested historical information as of the date of this writing.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes, I am sponsoring Exhibits EM-11 (RRJ-1) through EM-15 (RRJ-5) which provide forecasts of the elements that EVA was engaged to provide as well as some model inputs.

Q. Are these your final results?

A. Yes. However, if the outstanding requested information is ultimately produced by DTE, or if additional information becomes available, EVA reserves the right to update its forecasts.

Q. How is the remainder of your testimony organized?

A. The basis for each element of subsection 3(b) is discussed below.

II. ENERGY MARKET SALES

Q. Please explain your methodology for developing the forecast of Energy Market Sales.

A. Energy Market Sales are DTE's annual sales of power during the 2018 through 2021 period. As DTE participates in MISO, the output from its power plants is offered to MISO. The manner in which MISO dispatches the plants determines the generation from DTE's plants. MISO dispatches the plants economically, subject to operating constraints. DTE's plants are competing with other generation resources in MISO, and the competitiveness of each of DTE's assets relative to the other MISO assets determines its level of operation.

The forecast of energy sales therefore requires an analysis that incorporates the dispatch of DTE's units in the context of the entire MISO region and the regions which trade power with MISO. EVA's methodology includes the modeling of the DTE units in the context of overall MISO operations.

The modeling is done through the AURORAxmp hourly dispatch model ("Aurora"), which EVA licenses from EPIS, Inc. Aurora is an industry-standard dispatch model used by power producers, consultants, developers, analysts, and others to simulate utility operations and (among other things) forecast generation by fuel type and costs. While Aurora comes with default assumptions, EVA re-populates the majority of the model with its own assumptions including load growth, plant-specific-delivered fuel prices and operating parameters, overnight costs and operating parameters for new plants, power plant additions and retirements, and regulatory assumptions. Aurora's outputs include generation by plant and energy market pricing, among others.

Q. In what other applications has EVA used the Aurora model?

A. EVA regularly uses the Aurora model to develop its monthly, quarterly and annual forecasts of generation by unit and plant type. These outputs are translated into unit forecasts and comprise portions of EVA's coal and natural gas forecasts. EVA's plant-specific delivered price assumptions are used by a number of EVA clients in their own modeling efforts. EVA also uses Aurora for analysis of new and potential regulations and customized market analyses.

Q. Please describe your customized inputs into Aurora.

A. The Aurora model is very data-intensive. As mentioned, there are default values for the assumptions that EVA replaces with internally developed assumptions.

For this engagement, to be consistent with the analytics of other stakeholders, EVA used neutral third-party assumptions for several of the variables including load forecasts, gas prices and delivered coal prices.

Q. What load growth assumption was used in the analysis?

A. MISO's latest electricity demand outlook from the fall of 2016 was used. For Local Resource Zone 7 ("LRZ 7"), which comprises the MISO portion of Lower Michigan, the Compound Annual Growth Rate ("CAGR") between 2017 and 2021 was 1.1%. The demand for MISO as a whole also grew at a CAGR of 1.1% during that same period.

Q. What natural gas price forecast was used?

A. EVA used the NYMEX forward price curve dated June 29, 2017. This is provided below in Exhibit EM-11 (RRJ-1). The forward price curve represents what sellers and buyers are willing to pay today over the forecast period. EVA purchases an inflation outlook from Moody's Analytics which is updated quarterly.

Q. What delivered coal price forecast was used?

A. EVA used the actual consumed price of coal reported by DTE in its 2016 Form 1 filing to determine a base delivered coal price and then adjusted it by EVA's current escalations for coal and transportation.

Q. What other key assumptions were used?

A. EVA assumed that Entergy's 800-MW Palisades nuclear plant will close in September 2018 based on recent announcements by Entergy. The closure is "subject to timely receipt of certain MPSC approvals." The retirement of DTE's 272-MW River Rouge unit 3 in 2020 was also included in the analysis.

On the environmental side, EVA assumed that neither the Clean Power Plan ("CPP") nor the Effluent Limitation Guidelines ("ELG") would go into effect or have an impact during the period 2018 through 2021.

Q. What is the basis of your regulatory assumptions?

A. Prior to the November 2016 election, the Supreme Court had stayed implementation of the Clean Power Plan. A stay is a relatively rare event and requires at least two findings. The first is that the appeal is *likely* to prevail based upon its merits. The second is that absent a stay there is likely to be irreparable harm. Given the stay and a 2022 implementation date in the Final Rule, there does not seem to be any scenario in which a 2022 implementation would occur. The election of President Donald Trump changed the outlook for this rule further. On March 28, 2017, President Trump signed an Executive Order which, among other things, directs the EPA specifically to revisit the CPP and determine what actions should be taken to reduce the burden on development or use of domestically produced energy resources, including coal. The Department of Justice filed motions with the U.S. Court of Appeals for the District of Columbia Circuit advising the Court of these actions and requesting the Court hold in abeyance the cases challenging the CPP. The likely outcome is that there will be no implementation of the CPP as currently written. Given the time necessary to develop alternatives to the CPP, it is unlikely for a carbon regime to be put in place in the relevant time period.

The ELG situation has some similarities. A final rule was published in the Federal Register on November 3, 2015, which established the date that appeals could first be filed. A number of timely appeals were filed. The appeals were consolidated at the U.S. Court of Appeals for the Fifth Circuit. The initial arguments were filed with the Fifth Circuit in December 2016. Oral arguments were expected in 2017. Following the election, the Court agreed to suspend its review pending an internal EPA review and EPA issued an administrative stay delaying the compliance dates. Like the CPP, the ELG rule is unlikely to be in effect during the relevant time-period.

Q. Did you develop a generation forecast for DTE for this engagement?

A. Yes. EVA ran its Aurora model to develop a generation forecast through 2021, the results of which are provided in Exhibit EM-12 (RRJ-2).

Q. What sources of generation are included in your forecast of DTE's generation?

A. Two types of sources are included. The first is forecasted generation from DTE-owned power plants, which are listed in Exhibit EM-13 (RRJ-3). The second is generation related to purchase power agreements.

Q. What information did DTE provide related to their power purchase agreements?

A. DTE witness Wojtowicz provided in discovery responses EMDE-2.26 and EMDE-2.32a lists of existing power purchase agreements.

EVA reviewed the available information and extracted from the Aurora model the relevant plants so that it could forecast sales from contracted plants. EVA benchmarked the operations of the contracted plants against the amount of energy DTE purchased from them based on FERC Form 1 data.

Q. How did EVA translate the generation forecast into Energy Market Sales revenue?

A. Energy Market Sales revenue is the product of hourly generation and the hourly Locational Marginal Price ("LMP"). Generation and energy market prices are outputs of the Aurora modeling. EVA calculated the LMPs by adding the Aurora-produced energy market prices to the forecasted transmission congestion costs and the cost of marginal losses. EVA performed an hourly regression on historical LMP data to determine the correlation between congestion and losses and the energy component. The Energy Market Sales revenues by year are shown in Exhibit EM-14 (RRJ-4).

Q. Are there any other Aurora outputs that are included in the capacity rate calculation?

A. Yes. The total fuel cost forecasts, which are produced by the Aurora model, are included. Total fuel costs are the product of price per MMBTU of fuel and total MMBTUs consumed. EVA assumes that the fuel cost for wind and solar plants is zero. The forecast for DTE's total fuel cost is provided in Exhibit EM-15 (RRJ-5).

III. OFF-SYSTEM POWER SALES

Q. What are off-system power sales?

A. Off-system power sales are sale to parties that are outside of the service territory.

Q. Did you request and receive information on Off-System Power Sales?

A. I received some of the information requested regarding Off-System Power Sales.

Q. Please explain your methodology for forecasting Off-System Power Sales using the information available.

A. DTE witness Wojtowicz provided in discovery response ABDE1.11 five years of historical off-system power sales, all of which were zero. Additionally, witness

Wojtowicz in discovery response EMDE-2.6 stated that, "the Company is not forecasting any off-system power sales in the years 2017 through 2020 (where off-system power sales is [sic] assumed to mean sales outside of the PSCR mechanism). The only wholesale power sales the Company is forecasting are into the MISO wholesale energy market." Based on these responses, EVA is not forecasting any off-system power sales for DTE for the years 2017 through 2020.

IV. ANCILLARY SERVICES

Q. What are Ancillary Services?

A. Ancillary services includes services necessary to balance the transmission system as it moves electricity from generating sources to ultimate consumers as well as several other non-markets for ancillary services such as Black Start Service and Reactive Service. Generators may receive compensation from the grid operator for providing these services.

Q. Did you request and receive information on Ancillary Services from DTE?

A. Yes. In discovery responses EMDE-2.22 and EMDE-2.8, Witness Wojtowicz provided total historical ancillary service revenue for the years 2012 through 2016.

Q. Please explain your methodology for Ancillary Service Revenues for DTE.

A. EVA calculated the five-year historical average of Ancillary Service Sales as reported on the DTE's Form 1 filed with FERC and used this value for its forecast. This forecast is presented in Exhibit EM-14 (RRJ-4).

V. BILATERAL ENERGY SALES

Q. What are bilateral energy sales?

A. Bilateral sales are direct sales of power to a third party.

Q. Is there any recent history of bi-lateral sales for DTE?

A. No. DTE witness Wojtowicz in discovery response EMDE-2.24 states, "The Company had no unit-specific bilateral contracts in any of the years 2012 through 2016."

Q. Are you forecasting bi-lateral sales during the relevant period?

A. No. DTE witness Wojtowicz in discovery response EMDE-2.25 states, "The Company is not forecasting any unit-specific bilateral contracts in the years 2017 through 2020." Based on this information, EVA is not forecasting any bilateral sales for those years.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

12034906_2.docx

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

****

In the matter, on the Commission's own motion,	)	
to open a docket to implement the provisions of	)	
Section 6w of 2016 PA 341 for	)	**Case No. U-18248**
DTE ELECTRIC COMPANY'S	)	
service territory.	)	
____	)	

EXHIBITS OF

RUPERT R. ("ROB") JENNINGS

ON BEHALF OF

ENERGY MICHIGAN, INC.

Exhibit EM-11 (RRJ-1): Natural Gas Price Forecast

$/MMBtu

2017$	2017	2018	2019	2020	2021
Henry Hub	$3.08	$2.92	$2.70	$2.63	$2.60
MichCon	$3.02	$2.77	$2.56	$2.51	$2.50

Inflator	1.000	1.026	1.053	1.079	1.102

Nominal$	2017	2018	2019	2020	2021
Henry Hub	$3.08	$2.99	$2.85	$2.84	$2.86
MichCon	$3.02	$2.84	$2.69	$2.71	$2.76

Exhibit EM-12 (RRJ-2): DTE Electric Forecast Generation by Fuel Type

GWh

	2016A	2017	2018	2019	2020	2021
Coal	25,952	27,020	25,042	21,463	20,472	19,500
CCGT	0	0	0	0	0	0
Gas Turbine	1,905	1,428	1,570	1,780	2,210	2,376
Steam - Gas	336	243	626	147	750	939
Nuclear	9,147	8,441	8,479	9,579	8,656	8,479
Wind	2,617	2,753	2,753	2,753	2,758	2,753
Solar	1	6	6	6	6	6
Hydro	9	12	12	12	12	12
Other	656	644	644	644	644	644
Pump Storage	-304	-282	-282	-282	-282	-282
TOTAL	40,318	40,265	38,850	36,101	35,226	34,427

Exhibit EM-13 (RRJ-3): DTE-owned Generating Plants

Plant ID	Unit	Plant Name	DTE Share	Capacity* (MW)	Type	Notes
6034	ST1	Belle River	81%	520	Coal	
6034	ST2	Belle River	81%	520	Coal	
1733	1	Monroe	100%	758	Coal	
1733	2	Monroe	100%	773	Coal	
1733	3	Monroe	100%	773	Coal	
1733	4	Monroe	100%	762	Coal	
1740	2	River Rouge	100%	251	Coal	
1740	3	River Rouge	100%	272	Coal	Retiring June 2020
1743	1	St. Clair	100%	151	Coal	
1743	2	St. Clair	100%	154	Coal	
1743	3	St. Clair	100%	160	Coal	
1743	4	St. Clair	100%	151	Coal	
1743	6	St. Clair	100%	311	Coal	
1743	7	St. Clair	100%	440	Coal	
1745	7	Trenton Channel	100%	110	Coal	Retired April 2016
1745	8	Trenton Channel	100%	100	Coal	Retired April 2015
1745	9	Trenton Channel	100%	520	Coal	
1729	2	Fermi 2	100%	1,141	Nuclear	
6035	1	Greenwood	100%	785	Steam - Gas	
1740	1	River Rouge	100%	206	Gas Turbine	
55402	--	Renaissance GT	100%	612	Gas Turbine	
6035	--	Greenwood GT (3 units)	100%	75	Gas Turbine	
6034	--	Belle River GT (3 units)	100%	224	Gas Turbine	
1729	--	Fermi GT (4 units)	100%	48	Gas Turbine	
1730	--	Hancock GT (6 units)	100%	139	Gas Turbine	
1734	--	Northeast GT (7 units)	100%	116	Gas Turbine	
1743	--	St. Clair IC (2 units)	100%	5	Peaker	
1744	--	Superior GT (4 units)	100%	60	Gas Turbine	
1728	--	Delray GT (2 units)	100%	127	Gas Turbine	
6034	--	Belle River IC (5 units)	100%	14	Peaker	
1725	--	Colfax IC (5 units)	100%	14	Peaker	
1733	--	Monroe IC (5 units)	100%	14	Peaker	
1735	--	Oliver IC (5 units)	100%	14	Peaker	
1737	--	Placid IC (5 units)	100%	14	Peaker	
1739	--	Putnam IC (5 units)	100%	14	Peaker	
1740	--	River Rouge IC (4 units)	100%	14	Peaker	
1743	--	St. Clair GT (1 unit)	100%	19	Peaker	
1746	--	Wilmot IC (5 units)	100%	14	Peaker	
1713	--	Ludington	49%	985	Pump Storage	
58719	--	Brookfield Wind	100%	75	Wind	
57851	--	Sigel	100%	64	Wind	
58121	--	Echo Wind	100%	112	Wind	
57421	--	Gratiot Wind	100%	102	Wind	
	--	Pinnebog Wind	100%	51	Wind	
	--	Thumb Wind	100%	110	Wind	
60017	--	Domino Farms Solar	100%	1	Solar	
60018	--	Ford World Headquarters	100%	1	Solar	
60019	--	Greenwood Solar Farm	100%	2	Solar	

**Represents DTE Share*

Exhibit EM-14 (RRJ-4): Energy, Off-System, Ancillary Service, and Bilateral Sales Forecast

	2017	2018	2019	2020	2021
Energy Market Sales (GWh)	40,265	38,850	36,101	35,226	34,427
Energy Market Sales ($MM)	$1,497	$1,369	$1,263	$1,281	$1,242
Off-system Energy Sales ($MM)	$0	$0	$0	$0	$0
Ancillary Service Sales ($MM)	$16	$16	$16	$16	$16
Bilateral Energy Sales ($MM)	$0	$0	$0	$0	$0
Total Sales Revenue ($MM)	$1,513	$1,385	$1,279	$1,287	$1,241

Exhibit EM-15 (RRJ-5): DTE's Total Fuel Cost Forecast

	2017	2018	2019	2020	2021
Total Fuel Cost ($MM)	$837	$801	$710	$735	$731

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

****

In the matter, on the Commission's own motion, to open a docket to implement the provisions of Section 6w of 2016 PA 341 for **DTE ELECTRIC COMPANY'S** service territory.	))))))	**Case No. U-18248**

DIRECT TESTIMONY OF

LAEL E. CAMPBELL

ON BEHALF OF

ENERGY MICHIGAN, INC.

LAEL E. CAMPBELL
DIRECT TESTIMONY

Q. Please state your name and business address.

A. My name is Lael Campbell. My business address is 101 Constitution Avenue NW, Washington DC 20001.

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. I earned a Bachelor of Arts from Dickinson College in Carlisle, PA in 1994 and a Juris Doctorate from Washington and Lee University School of Law in 1998. I have been with Exelon and Constellation for over seven years. I currently serve as Director of Regulatory Affairs for Exelon. Prior to my current role, I served as Assistant General Counsel with Exelon where I was responsible for providing legal and regulatory support to Exelon Generation's wholesale trading and marketing business. Before that, I served as Senior Regulatory Counsel for Constellation, supporting the regulatory activities of the Constellation NewEnergy, Inc.'s, retail business, in addition to Constellation's wholesale market activities before state and Federal regulatory agencies across the country. My previous experience prior to joining Constellation includes over five years as a Senior Trial Attorney at the U.S. Commodity Futures Trading Commission, where I represented the agency in numerous matters relating to physical and financial commodity markets, including energy markets.

Q. What is the purpose of your testimony?

A. On behalf of Energy Michigan, I am discussing the concerns and flaws with DTE Electric Company's ("DTE") ("the Company") proposal to require choice customers to notify the company that they are exempt from any applicable state reliability mechanism ("SRM") charge, gives the Company authority to determine if an AES has procured sufficient capacity, and then require any choice customer who does not provide such notification in a manner acceptable to the Company to pay the SRM capacity charge, take "Full Service or Utility Capacity Service" and be directly billed by DTE. I will then propose that the SRM charge be assessed by the Company directly to Alternative Electric Suppliers ("AES") for the portion of AES load that the Commission has determined is subject to the charge, which will allow AES to manage capacity on behalf of customers on a portfolio basis – consistent with utility and MISO practice.

Q. How does DTE propose the SRM be billed and collected?

A. The Company proposes that all choice customers notify and provide documentation to the Company by April 1, 2018, demonstrating that the customer's AES has secured sufficient capacity for the full SRM term, June 1, 2018- May 31, 2022. If the customer fails to provide documentation, then they will be obligated to take full service or Utility Capacity Service from DTE for 30 years and be billed directly by the company for capacity. DTE's proposed tariff reads as follows:

> By April 1, 2018, each Retail Access Customers [sic] must notify DTE Electric in writing that it will not be returning to Full Service or initiating Utility Capacity Service beginning June 1, 2018 and provide

> documentation from their AES that demonstrates that the AES has secured sufficient capacity to serve the customer's load from June 1, 2018 through May 31, 2022. Failure to provide this notice will result in DTE Electric providing Utility Capacity Service to the Customer beginning with the June 2018 billing cycle and shall obligate the Customer to take Full Service or Utility Capacity Service from DTE Electric for 30 years. If at any time after Customers [sic] initial capacity notification to the Company, it is determined that Customer will not have access to capacity from its AES sufficient to serve Customer's load, the Company shall bill Customer the applicable capacity charge for the entire plan period regardless of when the capacity shortfall was discovered.[1]

Q. Do you have any concerns with the Company's proposal?

A. Yes. The Company's proposal is punitive and discriminatory to customers who exercise their right under Michigan law to choose to participate in the Retail Open Access program. Foremost, DTE's proposal to require this notification from customers is overly burdensome to the customer. The 4,906 individual customers participating in electric choice in DTE's territory[2] should not be burdened with a new requirement to be the intermediary between the AES and the Company and provide documentation of information that is squarely with the AES. Further, under the Company's proposal, even if a customer's AES does in fact have sufficient capacity to serve the customer, but the customer fails to include that documentation in its notification to the Company or provide documentation to the Company's satisfaction, that customer will still be subject to the SRM for 30 years. The Company does not define in the tariff what the standard for documentation will be, and the Company does not have the authority to decide whether documentation of capacity under PA 341 is satisfactory or not. Finally, the Company's

[1] DTE Proposed Tariffs Exhibit A-12 Retail Access Service Charge, p 9-10.

[2] MPSC Status of Electric Competition in Michigan Report for Calendar Year 2016.

proposal assumes that AESs designate particular megawatts to particular customers, which is not how AESs (or the utilities, for that matter) manage capacity resources. The proposal is unjustly burdensome to AESs, as it appears to require an AES to create separate documentation for each and every one of its retail customers regarding its procurement of sufficient capacity to serve that retail customer, and provide that documentation to each retail customer.

Q. Does the Company's proposal that requires AES customers that do not provide documentation to the Company's satisfaction to take Full Service or Utility Capacity Service for 30 years match the intent of PA 341?

A. No. Contrary to PA 341, the Company's proposal inserts the Company into a role that PA 341 reserves for the Commission, that being determining that an AES has demonstrated that it has owned or contractual rights to capacity for the portion of its load that will not be subject to the SRM. The Company proposal further exacerbates this by imposing a customer by customer standard that is not present in PA 341.[3]

Q. Are there other concerns?

A. Yes. To the extent that DTE is suggesting that it can return a customer to Full Service without that customer's consent, that proposal is in conflict with the Act. PA 341 clearly

[3] 6w(6) states that the capacity charge must be paid "for the portion of load" (distinguishable from each individual customer) taking service from the alternative electric supplier not covered by capacity self-supplied by the AES.

envisions that, at most, the utility could potentially provide capacity service for the customer while energy is provided by the AES. The law states:

> An electric provider shall provide capacity to meet the capacity obligation for the portion of that load taking service from an alternative electric supplier in the electric provider's service territory that is covered by the capacity charge during the period that any such capacity charge is effective.[4]

The law plainly states that even load "covered by the capacity charge" would continue to be "taking service from an alternative electric supplier". To the extent that the Company proposes to put any AES customer back on full service, that proposal violates PA 341.

Q. Do you have any other concerns with DTE's proposed customer notification requirement?

A. Yes. DTE's proposal, if approved, would result in forced switching of customers without customer consent or supplier default. Forced switching without affirmative customer consent is often referred to as "slamming." DTE's proposal requires affirmative action on the part of customers to avoid forced switching for their capacity service for a term of 30 years. Under DTE's proposal, customers who do not provide DTE's requisite notice regardless of reason could be obligated to pay for capacity service to both DTE pursuant to tariff and their AES pursuant to contract. DTE's draconian proposal is unjust and unreasonable and to the detriment of the customers DTE purports to serve.

[4] PA 341 Section 6w(7)

Q. What effect would it have if AESs were unable to manage capacity (including any SRM charge for a portion of load) on a portfolio basis, and instead had to pick and choose customers who would be charged the SRM by utilities?

A. It would significantly diminish the benefits of customers' participation in the retail open access program. AESs manage their customers' needs, and the resources to meet those needs, on a portfolio basis, no different than how the utilities manage a portfolio of resources to serve customers and do not designate specific resources to serve specific individual customers. The statute envisions this portfolio approach as 6w(6) states that, "the capacity charge… must be paid **for the portion of load** taking service from the alternative electric supplier not covered by… [capacity self-supplied by the AES]" (emphasis added). Eliminating the ability for the AES to manage the customer's capacity as part of a larger portfolio of resources and customers would be inconsistent PA 341 and will only serve to increase costs on customers subject to the SRM. It would also create an additional competitive disadvantage for AESs compared to the utilities, who have and will continue to serve their aggregate load through a combined portfolio of generation resources. Allowing AESs to manage the SRM charge on a portfolio level puts AESs on equal footing with the utilities. Like a utility, then, the AES can spread the SRM cost across its load base and not discriminate against individual customers, some of whom would otherwise have to pay the SRM and some of whom would not.

Q. Do you have other concerns?

A. Yes. Requiring the customers to provide notification to the utility and placing the SRM charge directly on the customers will place the customer at the center of disputes related to the AES's demonstration of capacity. Such disputes would be better managed by the AES and the Company as those two entities would be more knowledgeable of the capacity demonstration and SRM process.

Q. Does Energy Michigan have an alternative proposal for billing the SRM?

A. Yes. The best way to address the issues raised above is to allow the AES to continue to manage capacity costs for all of their customers by assessing the SRM capacity charge to the AES. However, let me emphasize that this is a practical solution and is not intended to address any potential legal issues related to the capacity charge that might arise from this proceeding. In other words, this proposal is not an endorsement by Energy Michigan or its members of the legality of any particular charge, it just proposes that any such charge should be assessed in a manner consistent with utility and MISO practice for capacity costs – i.e., on a portfolio basis.

Q. Does PA 341 allow for or envision AES handling the assessed SRM?

A. Yes. PA 341 requires that "the capacity charge must be applied to alternative electric load"[5] but it envisions that the AES would pay the capacity charge. The law states explicitly in section 6W(6) that it would, in fact, be the AES paying the capacity charge: "Any electric provider that has previously demonstrated that it can meet all or a portion of its capacity obligations shall give notice to the commission by September 1 of the 4 years before the beginning of the applicable planning year if it does not expect to meet

[5] PA 341 Section 6W(3)

the capacity obligation and instead expects to pay a capacity charge".[6] Further PA 341 is clear that that the capacity demonstration requirement is the responsibility of the AES.[7] It is consistent with the statute, then, for any charge that results from a capacity demonstration of an AES to be assessed to an AES, which then applies it to its load.

Q. How would the AES being assessed benefit customers?

A. If the AES is assessed the capacity charge, the AES would continue to be able to manage capacity for customers on a portfolio basis, allowing all of the AES customers to benefit from an AES's total portfolio of resources, instead of only requiring some customers to bear the brunt of the SRM. Under this approach AESs can, if they choose, reduce the impact of the SRM charge on customers by blending those costs with other, potentially cheaper, assets in its capacity portfolio to meet its capacity obligations. Furthermore, it places the responsibility for handling any potential regulatory disputes with the utility squarely with the AES instead of the customer, thus sparing the customer potential litigation costs.

Q. If the SRM is assessed to the AES, who would be responsible for the customer's capacity obligation with MISO?

A. The LSE's capacity obligation at MISO will stay with the AES for all of its load.

Q. What price would an AES be billed for the SRM?

---

[6] PA 341 Section 6W(6), emphasis added.

[7] PA 341 Section 6W(6)

A. Because the AES will be responsible in the eyes of MISO for its customers' capacity obligations, the AES will have to pay the Planning Resource Auction ("PRA") clearing price for that load in each MISO annual auction. In order to avoid double billing for capacity, the AES would be billed the SRM charge by the utility in an amount equal to the SRM minus the PRA clearing price for the applicable delivery year.

Q. Does this deprive the utility of the full SRM charge?

A. No, the utility is selling its capacity into the PRA and receiving the PRA clearing price, so when an AES pays the SRM less the PRA price it simply provides the utility with the remaining amount so that the utility receives the full SRM charge for the capacity used to serve the portion of AES load subject to the SRM.

Q. So is the utility billing the AES for the SRM capacity charge at the same time that MISO is billing the AES for capacity?

A. Yes. The billing for capacity by both MISO (for the PRA), and by the utilities for the SRM amount, should marry up as much as possible and occur during the same applicable delivery year. Further, the amount an AES is billed by the utility for the SRM should be apportioned to the AES's load the same way that MISO does it, by looking at the Peak Load Contribution ("PLC") of the AES's load for that delivery year (as established by MISO).

Q. Does this conclude your testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

****

In the matter, on the Commission's own motion,	)	
to open a docket to implement the provisions of	)	
Section 6w of 2016 PA 341for	)	**Case No. U-18248**
DTE ELECTRIC COMPANY'S	)	
service territory.	)	
______________________________________	)	

PROOF OF SERVICE

STATE OF MICHIGAN)
) ss.
COUNTY OF INGHAM)

Kimberly J. Champagne, the undersigned, being first duly sworn, deposes and says that she is a Legal Secretary at Varnum LLP and that on the 21st day of July, 2017, she served a copy of the Direct Testimonies and Exhibits of Alex J. Zakem, Ralph C. Smith, Rupert R. ("Rob") Jennings and Lael E. Campbell on behalf of Energy Michigan Inc., as well as this Proof of Service upon those individuals listed on the attached Service List via email at their last known addresses.

Kimberly Champagne

Digitally signed by Kimberly Champagne
DN: cn=Kimberly Champagne, o=Varnum LLP, ou=Lansing, email=kjchampagne@varnumlaw.com, c=US
Date: 2017.07.21 16:03:19 -04'00'

____
Kimberly J. Champagne

SERVICE LIST
MPSC CASE NO. U-18248

Administrative Law Judge
Hon. Mark D. Eyster
Administrative Law Judge
Michigan Public Service Comm.
7109 W. Saginaw Hwy., 3rd Floor
Lansing, MI 48917
eysterm@michigan.gov

Counsel for DTE Electric Company
Jon P. Christinidis
Andrea Hayden
Richard P. Middleton
One Detroit Plaza, 688 WCB
Detroit, MI 48826
christinidisj@dteenergy.com
andrea.hayden@dteenergy.com
richard.middleton@dteenergy.com
mpscfilings@dteenergy.com

Counsel for the Michigan Public Service Commission
Lauren D. Donofrio
Meredith R. Beidler
Bryan A. Brandenburg
7109 W. Saginaw Hwy., 3rd Floor
Lansing, MI 48919
donofriol@michigan.gov
beidlerm@michigan.gov
brandenburgb@michigan.gov

Counsel for the Sierra Club
Christopher M. Bzdok
Tracy Jane Andrews
Olson, Bzdok & Howard, P.C.
420 E. Front St.
Traverse City, MI 49686
chris@envlaw.com
tjandrews@envlaw.com
karla@envlaw.com
kimberly@envlaw.com

Counsel for Residential Customer Group
Don L. Keskey
Brian W. Coyer
Public Law Resource Center PLLC
University Office Place
333 Albert Avenue, Suite 425
East Lansing, MI 48823
donkeskey@publiclawresourcecenter.com
bwcoyer@publiclawresourcecenter.com

Counsel for ABATE
Michael J. Pattwell
Sean P. Gallagher
Clark Hill PLC
212 E. Grand River Ave.
Lansing, MI 48906
mpattwell@clarkhill.com
sgallagher@clarkhill.com

Stephen A. Campbell
500 Woodward Ave.
Detroit, MI 48226
scampbell@clarkhill.com

Counsel for Wal-Mart Stores East, LP and Sam's East, Inc.
Melissa M. Horne
Higgins, Cavanagh & Cooney, LLP
10 Dorrance St., Ste. 400
Providence, RI 02903
mhorne@hcc-law.com

Counsel for Spartan Renewable Energy Inc.
Jason Hanselman
Dykema Gossett, PLLC
201 Townsend, Ste. 900
Lansing, MI 48933
jhanselman@dykema.com

Counsel for Wolverine Power Marketing Cooperative, Inc.
Richard Aaron
Courtney Kissel
Dykema Gossett, PLLC
201 Townsend, Ste. 900
Lansing, MI 48933
raaron@dykema.com
ckissel@dykema.com

Counsel for Constellation NewEnergy, Inc.
Jennifer Utter Heston
Fraser, Trebilcock, Davis & Dunlap, PC
124 W. Allegan, Ste. 1000
Lansing, MI 48933
jheston@fraserlawfirm.com

Counsel for Local 223, Utility Workers Union of America (UWUA), AFL-CIO
John R. Canzano
Patrick J. Rorai
McKnight, Canzano, Smith, Radtke & Brault, P.C.
423 N. Main Street, Suite 200
Royal Oak, MI 48067
jcanzano@michworkerlaw.com
prorai@michworkerlaw.com

Counsel for Michigan Municipal Electric Association
Nolan J. Moody
Peter H. Ellsworth
Dickinson Wright, PLLC
215 S. Washington Square, Ste. 200
Lansing, MI 48933
nmoody@dickinsonwright.com
pellsworth@dickinsonwright.com

Jim B. Weeks
Michigan Municipal Electric Association
809 Centennial Way
Lansing, MI 48917
jweeks@mpower.org

Michigan Department of Attorney General Special Litigation Unit
Michael E. Moody
Assistant Attorney General
G. Mennen Williams Bldg., 6th Floor
525 W. Ottawa St.
Lansing, MI 48909
moodym2@michigan.gov
ag-enra-spec-lit@michigan.gov

Counsel for The Kroger Company
Kurt J. Boehm
Jody Kyler Cohn
Boehm, Kurtz & Lowry
36 East Seventh St., Ste. 1510
Cincinnati, Ohio 45202
KBoehm@BKLlawfirm.com
JKylerCohn@BKLlawfirm.com