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 2016 PA 341 for DTE Electric Company's service territory.
/

Case No. U-18248

Volume 3

CROSS-EXAMINATION

Proceedings held in the above-entitled matter before Mark D. Eyster, J.D., Administrative Law Judge with MAHS, At the Michigan Public Service Commission, 7109 West Saginaw Highway, Lake Michigan Room, Lansing, Michigan, on Thursday, August 31, 2017, at 9:17 a.m.

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Commission Staff

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REPORTED BY: Lori Anne Penn (CSR-1315)

I N D E X

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Lansing, Michigan
Thursday, August 31, 2017
At 9:17 a.m.

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(Hearing resumes following adjournment of Wednesday, June 14, 2017.)

(Documents marked for identification by the Court Reporter as Exhibit Nos. A-1 through A-8, A-9 Revised, A-10 Revised, A-11 Corrected, A-12 Corrected, A-13 through A-16, A-18 through A-21; EM-1 through EM-16; CNE-1 and CNE-2; AB-1 through AB-3; S-1.1, S-1.2, S-1.3, S-1.4, S-1.5, S-2 through S-7.)

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JUDGE EYSTER: O.K. We are on the record in Case U-18248. I'm Administrative Law Judge Mark D. Eyster. This is the date set for the evidentiary hearing in this matter.

Could I have counsel for the parties please identify themselves on the record.

MR. MIDDLETON: Good morning, your Honor. Richard P. Middleton appearing on behalf of DTE Electric.

MS. DONOFRIO: Good morning. Lauren Donofrio and Meredith Beidler appearing on behalf of the Michigan Public Service Commission Staff.

MR. BOEHM: Good morning, your Honor. Kurt Boehm appearing on behalf of The Kroger Company.

MR. MOODY: Good morning, your Honor. Michael Moody on behalf of Attorney General Bill Schuette.

MS. HESTON: Good morning, your Honor. Jennifer Heston of the Law Firm of Fraser, Trebilcock, Davis & Dunlap appearing on behalf of Constellation NewEnergy, Inc.

MS. NEWELL: Good morning, your Honor. Toni Newell of the Varnum Law Firm appearing on behalf of Energy Michigan and the Michigan Chemistry Council.

MR. PATTWELL: Michael Pattwell, Clark Hill, appearing on behalf of ABATE.

JUDGE EYSTER: Mr. Middleton, how would you like to proceed? I don't know if you want to address your motion first or bind in your testimony and we'll address your motion when we get to Mr. Boehm's portion of the hearing.

MR. MIDDLETON: We can take them in order that way. We can put our case in first, and then as these two issues come up, we can discuss those.

JUDGE EYSTER: O.K. Please proceed.

MR. MIDDLETON: Thank you, your Honor. Prior to the hearing this morning, all the parties agreed to waive cross of DTE witnesses, no need for witnesses to appear at the hearing since the parties agreed to allow stipulation into the record of the prefiled testimony and exhibits. So I'll go through those and then move for admission at the end for all of the exhibits and the witnesses.

In this case the Company filed the direct testimony of Don Stanczak, consisting of a cover page and 20 pages of questions and answers. Mr. Stanczak did not sponsor any exhibits associated with that. He also filed rebuttal testimony, which consisted of a cover and 15 pages. Again, no exhibits were associated with his rebuttal.

The Company also filed the direct testimony of Timothy A. Bloch, consisting of a cover and 13 pages of questions and answers. There were two exhibits sponsored by Mr. Bloch, and to some extent also sponsored by other parties, but given the stipulation, we'll just attribute these to Mr. Bloch at this point. Those exhibits were marked for identification purposes as Exhibits A-11 and A-12. Mr. Bloch also filed rebuttal testimony, consisting of a cover page and four pages of questions and answers. There were no exhibits associated with his rebuttal.

The Company also filed the direct

testimony of Philip W. Dennis, consisting of a cover page and six pages of questions and answers. He sponsored Exhibit A-16 associated with his direct testimony. He also filed rebuttal testimony, consisting of a cover page and four pages of questions and answers. He sponsored Exhibit A-21 associated with his rebuttal testimony.

Kelly Holmes filed direct testimony, consisting of a cover page and ten pages of questions and answers. She also cosponsors Exhibits A-11 and A-12. She also filed rebuttal, consisting of a cover and three pages of questions and answers.

The Company filed the direct testimony of Thomas W. Lacey, it consists of a cover page and seven pages of questions and answers. Mr. Lacey sponsored Exhibits A-13, A-14, and A-15 associated with his direct testimony. Mr. Lacey also filed rebuttal testimony, consisting of a cover and 16 pages of questions and answers. He also sponsored three exhibits associated with his rebuttal, those are identified as Exhibit A-18, A-19, and A-20.

Michael Williams filed direct testimony in this proceeding, it consists of a cover page and six pages of questions and answers. He also cosponsored Exhibits A-11 and A-12. He filed rebuttal testimony as well, it consists of a cover page and four pages of questions and answers. There were no exhibits associated with his rebuttal.

Angela P. Wojtowicz provided direct testimony in this proceeding, consisting of a cover page and 20 pages of questions and answers. That has been revised to reflect reference to a calculation error correction, which will also appear on two of the exhibits; that was handed out to the parties this morning, your Honor. Angela Wojtowicz sponsored the following exhibits in this proceeding: Exhibits A-1, A-2, A-3, A-4, A-5, A-6, A-7, A-8, A-9, and A-10. A-9 and A-10 are revised to reflect the same calculation error. Ms. Wojtowicz also sponsored rebuttal testimony, consisting of a cover and seven pages of questions and answers, and she did not have any rebuttal exhibits associated with that.

So at this time, your Honor, we would move for the admission of the direct and rebuttal testimony of all the witnesses identified, and for the admission of Exhibits A-1 through A-21, noting that A-12, was corrected earlier and already filed with the Commission because it had an incorrect case caption on Exhibit A-12, and that A-9 and A-10 are being provided this morning with the revised calculation. I would add that there is no A-17, there's a gap in the -- it's not continuous, there is no Exhibit A-17.

JUDGE EYSTER: Are there any objections to the motion?

O.K. Hearing none, the testimony is bound in and the exhibits are admitted.

(Testimony bound in.)

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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.	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

DON M. STANCZAK

DTE ELECTRIC COMPANY
QUALIFICATIONS OF DON M. STANCZAK

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No.

Q. Please state your name, business address and by whom you are employed.

A. My name is Don M. Stanczak. My business address is One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Energy Corporate Services, LLC a subsidiary of DTE Energy as Vice President, Regulatory Affairs.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of DTE Electric Company (DTE Electric or Company).

Q. What is your education background?

A. I received a Bachelor of Science Degree in Business Administration, with a major in Finance, from Central Michigan University. In addition, I received a Master of Business Administration Degree, with a major in Accounting, from Wayne State University.

Q. What work experience do you have?

A. I joined Michigan Consolidated Gas Company (MichCon) in 1983 and through 1994 had several assignments of increasing responsibility in a number of areas within MichCon, including Financial Services, Regulatory Affairs, Corporate Planning, Gas Supply and Supply Chain. In 1994, I was promoted to Director, Market Planning. In 1999, I transferred to Gas Transmission and Resource Planning as Director. In 2000 I moved back to Regulatory Affairs as Director, responsible for all of MichCon's regulatory activities. In 2001, MichCon's parent, MCN Energy, was acquired by DTE Energy, DTE Electric's (formerly Detroit Edison) parent. In 2005, I transitioned my responsibility to Director for DTE Electric's regulatory activities. In 2013, I assumed my present position having responsibility for the development and

Line No.

implementation of regulatory strategy and administration for both DTE Electric and DTE Gas (formerly MichCon).

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

A. Yes. I sponsored testimony in the following DTE Electric, Detroit Edison, DTE Gas, and MichCon cases:

U-10544	MichCon Facility Application
U-10547	MichCon Facility Application
U-10744	MichCon Conservation Plan
U-10640	MichCon GCR Plan
U-10915	MichCon GCR Plan
U-11145	MichCon GCR Plan
U-12762	MichCon GCR Suspension Termination
U-13060	MichCon GCR Plan
U-13060-R	MichCon GCR Reconciliation
U-13549-R	MichCon GCR Reconciliation
U-13808	Detroit Edison Rate Case
U-13898	MichCon Rate Case
U-13933	Detroit Edison Low-Income Credit
U-14399	Detroit Edison Rate Unbundling
U-14428	Detroit Edison Other Post Employment Benefit Equalization Mechanism
U-15768	Detroit Edison Rate Case
U-16472	Detroit Edison Rate Case

U-16489	Detroit Edison deferred pension and post-employment benefits expense for future amortization and recovery
U-16780	Detroit Edison Revenue Decoupling Mechanism Reconciliation
U-16952	Detroit Edison 2011 Choice Incentive Mechanism Reconciliation
U-17437	DTE Electric PLD Transitional Cost Recovery Plan
U-17689	DTE Electric Public Act 169 of 2014 Filing
U-17767	DTE Electric Rate Case
U-17999	DTE Gas Rate Case
U-18014	DTE Electric Rate Case

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Q. Why has the Company filed its application in this proceeding?

A. On January 20, 2017 the Commission issued an order, subsequently modified by two additional orders issued on February 28, 2017 and March 10, 2017, establishing this proceeding. In its orders, the Commission directed the Company, in the instant application, to address various aspects related to the implementation of 2016 Public Act 341 ("PA 341"), specifically related to the establishment of a State Reliability Mechanism ("SRM"), a generation related capacity charge and the associated annual review, and reconciliation of the capacity charge as required by PA 341.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to:

- Propose the appropriate term for the SRM and the capacity charge;
- Provide an overview of the Company's proposed capacity charge calculation and other aspects of the capacity charge;
- Address how the annual review of the capacity charge is proposed to be conducted; and
- Outline the Company's proposed reconciliation methodology for the capacity charge.

Q. Are you sponsoring any exhibits in this proceeding?

A. No, I am not.

Q. In its orders initiating this proceeding, specifically what issues did the Commission direct DTE Electric to address in its application in this proceeding?

A. In its March 10, 2017 order in this proceeding, the Commission directed the Company to file an application by April 11, 2017, supported by testimony, exhibits, and workpapers to implement a SRM in accordance other directives in that Order. Further in its March 10, 2017 Order in this proceeding, the Commission acknowledged that a MISO / FERC Prevailing State Compensation Mechanism ("PSCM") would likely not be implemented anytime soon in light of recent FERC action relative to MISO's proposed PSCM. Thus, the Commission directed DTE Electric to focus on issues associated with a SRM in this proceeding.

Q. How long does DTE Electric propose that the SRM and capacity charge be in place?

A. Section 6w(2) of PA 341 indicates that an SRM must be in place for a minimum of four consecutive planning years. However, the Company proposes that the SRM be in place indefinitely, and the associated capacity charge be in place for 30 years.

Q. Why is the Company proposing that the SRM be in place indefinitely and capacity charge be in place for 30 years when PA 341 requires a minimum term of only four years?

A. The SRM should be in place for an extended period of time for several reasons. First, since the State's generation fleet transition away from coal to gas and renewable generation will likely play out over an extended period, the SRM should be in place to provide the essential review of capacity availability by the Commission during this period. Specifically, because generation capacity could be scarce for an extended transition period, the Commission should review, on a continuing basis, all energy suppliers' ability to provide the required generation capacity to serve their customers. Second, DTE, as well as other utilities, will be investing in new generating plants that will have an operating life of 30 or more years. Therefore, the opportunity to apply a generation capacity charge should be available to the Commission for at least the minimum expected life of these new plants.

Q. Does DTE Electric expect to have the required generation capacity necessary to serve its customers over the next five years?

A. As addressed by Company Witness Ms. Wojtowicz, on a Planning Reserve Margin Requirement ("PRMR") basis as defined by MISO, DTE Electric expects to generally have enough capacity to serve all of its current bundled service customers. Over the next five years, the Company is expected to have, within several hundred MWs, enough resources either owned or under contract to provide the generation capacity for all of its current bundled service customers on a PRMR basis. Although there are several years that the Company may be slightly short of its full PRMR requirements, any potential shortfall is expected to be no more than about two or three percent of the total PRMR capacity requirements. Thus, DTE Electric expects to have all, or virtually all, of the capacity necessary to serve its current bundled service customers.

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. Prior to the passage of PA 341 the

Company had no expectation that it would be required to provide for the generation capacity needs of customers on Choice. In fact, it would have been imprudent and redundant for the Company to build or purchase excess capacity on behalf of Choice customers prior to the passage of PA 341 as it would have resulted in higher costs to the Company's bundled service customers without providing any benefits to those customers.

Q. Why would it have been imprudent and redundant to procure excess generation capacity on behalf of Choice customers prior to the passage of PA 341?

A. As I indicated earlier, in the past, AESs serving Choice customers had the sole responsibility of providing generation capacity for Choice customers. Thus, in the past, it would have been redundant for DTE Electric to ***also*** secure generation capacity on behalf of Choice customers. In addition, since Choice customers only pay DTE Electric for electric distribution service, any electric generation capacity costs incurred by the Company to meet the needs of Choice customers would have been borne solely by the Company's bundled service customers. This would have resulted in inappropriate cross subsidization. That is, the Company's bundled service customers would have been subsidizing Choice customers by paying for generation capacity procured exclusively to provide service to Choice customers.

Q. Why doesn't the Company know if it will need to provide capacity for Choice customers in the future?

A. Generally, PA 341 requires that beginning for MISO planning year 2018/19, all electric providers, including AESs, demonstrate that they have the required generation capacity to serve their customers' requirements. In the case of an AES, if it does not have the required capacity, that load will be required to pay a capacity charge to the applicable utility and the utility will be required to provide the necessary capacity. This review of the AESs capacity position will not be initiated for the first time until the seventh business day of February 2018. Therefore, at this time it is not known if any or all of the load currently served by AESs will be looking to DTE Electric to supply its capacity needs. To put this into perspective, PA 341 could potentially require DTE Electric to attempt to procure as much as 1,000 MWs of generation capacity between February and April of 2018, for the 2018 MISO planning year and for at least three subsequent MISO planning years thru May 2022.

Q. If Choice customers elect to rely on the Company for their generation capacity needs, will the Company be able to secure enough capacity to satisfy that demand?

A. Should Choice customers look to DTE for their generation capacity needs, the Company will do everything prudently possible to secure the required capacity. However, as addressed by Witness Wojtowicz, MISO and more specifically MISO Zone 7, may not have enough firm physical capacity to serve all demand in the future.

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)) requires 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. After the initial four-year period, Choice customers will have the ability each year to choose to take capacity service from the Company or an AES four years in the future. Therefore, after the initial four years of the SRM, should a Choice customer elect to take capacity service from the Company, at a minimum they are only required to pay the capacity charge for that one year, four years in the future. Thus, after the initial four-year period of the SRM, Choice customers will have the ability, with four years notice, to switch back and forth between receiving capacity service from DTE Electric and their AES. However, as I will address later in my testimony, the Company is seeking a longer required term for the capacity charge.

Q. In the future, if Choice customers choose to rely on DTE Electric to provide the required capacity to serve their requirements, will DTE Electric be able to supply that capacity?

A. As I indicated earlier and as more fully explained by Witness Wojtowicz, for the next few MISO planning years, the Company has generally enough capacity to serve its bundled service customers. For the 2018/19 planning year, the Company is currently expected to be 200-300 MW short and is currently working on options to address that shortfall. However, if a significant amount of Choice load plans to rely on DTE Electric for its capacity needs, the Company may not be able to procure the required capacity to meet that need. Unfortunately, Act 341 does not appear to contemplate an overall capacity shortfall within MISO. The legislation effectively assumes that a utility will be able to secure the required incremental generation capacity if AESs are unable to secure the required capacity to serve their customers. In other words, Act 341 is structured to assign responsibility for procuring generation capacity to the utilities, at the time that AESs are no longer able to procure capacity to serve their customers. Thus, at the very moment capacity is likely to not be available in the market, or to be extremely expensive, Act 341 requires the utilities to acquire capacity on behalf of Choice customers.

Q. How does the Company propose to address a potential future situation in which the Company is unable to procure all the required capacity necessary to serve Choice customers?

A. First, the Company will always, to the extent generation capacity is available, procure the required incremental capacity and charge all customers, both Choice and bundled service, a capacity charge that reflects the full embedded cost of all the Company's capacity. However, notwithstanding our best efforts, we may not be able to procure the required capacity to serve all customers if a significant amount of Choice load returns to DTE Electric; this is most likely to occur in the short-term. Should the Company be unable to secure all the required capacity, a reasonable and appropriate way to deal with such a situation is for the Company to charge a reduced interruptible capacity charge for Choice load that is not supported by either Company owned or purchased capacity.

Q. Why is it appropriate to potentially provide interruptible generation capacity service to Choice customers?

A. As I indicated earlier in my testimony, PA 341 requires that AESs secure generation capacity for their customers, or in the alternative the load is required to pay a capacity charge to the applicable utility. In addition, the utility is required to demonstrate that it has sufficient capacity to meet its requirements. Should a situation occur where there is not enough available capacity to serve Choice customers, it would be inappropriate for the Company to charge a firm service capacity charge to all customers since the Company would be unable to provide firm capacity resources to meet its PRMR. In addition, it would be equally unfair to expose all customers to interruption of service due to a capacity shortfall. Instead, the Company proposes to charge Choice customers a capacity related interruptible rate and provide interruptible capacity service when adequate levels of generation capacity are not available. As further discussed below, this charge will be the same rate which DTE Electric's current bundled service customers would pay for capacity who are taking interruptible service. Charging an interruptible rate accomplishes the following: 1) ensures that customers are paying for the service that they are getting, and 2) customers paying a lower rate for generation capacity service are the first customers interrupted should a physical shortfall occur.

Q. How will the Company establish a queue for existing Choice customers either returning to bundled service or returning to capacity only service?

A. DTE will establish a capacity queue with priority based first on the return date of the Choice customer then on the date the Choice customer provided the return notice. As discussed further by Witness Wojtowicz, the Company's capacity queue will not discriminate between Choice customers returning to bundled service or Choice customers returning for capacity only. In other words, all Choice customers returning, for any reason, to DTE Electric capacity service, will be placed in the capacity queue according to return date and be provided firm capacity service as long as it is available. Once available capacity has been depleted, remaining Choice customers seeking DTE Electric capacity will be put on the Company's interruptible capacity rate.

Q. Rather than provide interruptible service to Choice customers, would it be more appropriate to secure the necessary firm generation capacity through the annual MISO auction?

A. To the extent real firm physical generation capacity is available through the MISO auction, the Company plans to secure that real physical capacity. However, as explained in more detail by Witness Wojtowicz, once there is no capacity available in the market, the cost of capacity in the MISO auction goes to the Cost Of New Entry ("CONE"). Thus, the Company could pay CONE for the required capacity, but of course the physical capacity would not really exist. Therefore, the Company does not see this as an appropriate way to address a physical capacity shortfall.

Q. Does PA 341 allow for or contemplate an interruptible capacity charge for Choice customers as you just described?

A. PA 341 does not explicitly address an interruptible capacity charge, but it also does not address the possibility of there not being enough capacity available to serve load returning to utility service. As previously discussed, PA 341 requires that AESs demonstrate that they have acquired firm generation capacity or the AESs load is subject to a utility capacity charge. If the Company is unable to procure sufficient capacity resources to serve all the returning Choice load, then the Company has an obligation to its bundled customers, who have been paying DTE's full embedded cost of capacity consistently for years, to continue to provide the same level of service. If there is not sufficient capacity to serve all customers on a firm basis, then the Company believes that the reasonable and prudent alternative is for Choice customers that returned to the utility be served on an interruptible basis.

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Q. Is the Company proposing to apply the same capacity charge to all of its customers regardless of whether they are on Choice or are bundled service customers?

A. Yes. As required by PA 341, and as more fully addressed by Company Witness Mr. Lacey, all customer classes will be allocated the same amount of generation capacity costs and all similarly situated customers, both Choice and bundled service will pay the same rate for generation capacity. That is, all Choice and bundled service customers paying for firm capacity will pay the same rate and all customers, both bundled service and Choice, receiving interruptible capacity service will similarly pay the same rates.

Q. Is it reasonable for electric Choice customers to pay the same full embedded cost of DTE Electric's generation fleet as bundled customers even though the Choice customers are buying their energy from a third party?

A. Yes, it is reasonable for electric Choice customers to pay the same full embedded cost of DTE's electric generation fleet as bundled customers even though Choice customers are buying their energy from a third party. Not only is it reasonable for Choice customers to pay the same rate for capacity as bundled customers I believe it is expressly required by 6w(3) of PA 341. The service reliability provided by DTE's generation capacity is the same for the Choice customers as it is for bundled customers. With the exception of its interruptible services, the Company serves all customers, bundled and Choice, with the same level of service relative to generation capacity.

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Q. Will Choice customers paying an interruptible capacity charge be interrupted on the same basis as the Company's existing interruptible customers?

A. Yes. Choice customers who are placed on an interruptible capacity charge tariff will be treated consistently with bundled customers taking the same level of service. That is, interruptible bundled and interruptible Choice customers will be subject to interruption at the same time. Bundled and Choice customers paying the firm service capacity charge will be the last customers interrupted should a shortfall occur.

Q. Is the Company proposing any changes to the current return to service requirements in conjunction with this filing?

A. Yes. The Company is proposing that prospectively, all Electric Choice customers returning to either bundled service, or capacity only service, will be provided firm capacity service subject to availability. If DTE Electric has surplus available capacity at the time the returning customer applies for capacity service, the Company will waive the four-year notice requirement and immediately provide firm capacity service. However, if DTE does not have capacity available, an Electric Choice customer must provide the Company four years advance notice of returning to bundled, or capacity only service, in order to be guaranteed firm capacity service. After the four-year notice period, DTE Electric will provide the customer with firm capacity service.

Q. Does the Company propose to apply the same four-year notice requirement to new customers of DTE Electric, that is, brand new businesses and homes?

A. No.

Q. Why is the Company proposing to treat returning Choice customers different than new customers?

A. With respect to the normal addition of new small businesses and homes, as would be expected, the Company routinely plans for the attachment of such new load. More specifically, the Company has a sophisticated model that forecasts economic activity, and related customer count and load growth, and incorporates the anticipated growth into our long-term generation planning. With regard to new large industrial customers, the Company typically has years of advance notice. That is, large new customers typically contact the Company years in advance of the needed electric service. This early notification provides the required time to plan for and arrange the required distribution and generation facilities to serve the new customers. In contrast, relative to the Company's ability to forecast the attachment of new residential and small commercial customers, there is no way to accurately forecast the level of small customer migrations from Choice to bundled service. Similarly, relative to large industrial customers, there is no new construction notice period relative to the migration of Choice customers to bundled service. Therefore, the four-year notice period is essentially a proxy for the notice period already inherent in the process relative to attaching new industrial load.

Q. Once a Choice customer returns to bundled or capacity only service after the four-year notice period, how long is the Company proposing that customer be obligated to continue to pay for firm capacity service?

A. Once an Electric Choice customer returns for either bundled or capacity only service, they must stay with the Company's capacity service for a 30-year period. This will provide the needed assurance that the costs associated with any asset built to support the required capacity can be recovered from the customer. Therefore, I have instructed Company Witness Mr. Bloch to modify the EC2 tariff to adjust these provisions in the existing return to service section of the rate book.

Q. Once a Choice customer provides notice that they want to take bundled or capacity only service is that election revocable?

A. No. Once the election is made to take bundled or capacity only service that election is irrevocable, the customer must stay on bundled or capacity only service for 30 years.

Q. Why is the Company proposing that the election to take bundled or capacity only service be irrevocable?

A. As I indicated earlier, once a Choice customer notifies the Company of their desire to utilize Company generation capacity, the Company will do everything prudent to secure the required capacity, up to and including building a new power plant. Once such a decision is made to secure the required capacity, the customer must be obligated to take service from the incremental source of generation capacity procured on behalf of the customers. Without a long-term commitment by the returning Choice customer, it would be imprudent for the Company to make a long-term commitment for the incremental capacity required to serve the returning customer.

Q. What costs are reflected in the Company's proposed capacity charge?

A. All Production related costs which were approved in the Commission's January 31, 2017 order in Case No. U-18014, except fuel, variable operation and maintenance ("O&M") expense, and non-capacity related purchased power are included in the capacity charge. In addition, capacity related costs associated with purchase power are also included as part of the capacity charge.

Q. What types of capacity related costs are included in purchase power?

A. The Company pays capacity costs related to its PURPA/PA2 contracts and renewable energy resources; both company owned and related to purchase power agreements. Witness Wojtowicz determines these costs from DTE Electric's 2017 PSCR Plan case filed on September 30, 2016.

Q. Are the generation capacity costs you just described consistent with the requirement of PA 341?

A. Yes. Witness Lacey has included all capacity related generation costs included in DTE's base rates, surcharges and power supply cost recovery cases consistent with PA 341, section 6w (3) (a). These costs do not include fuel, variable O&M, nor non-capacity purchased power expenses. The proceeds of energy market sales, net of fuel, are subtracted from those costs.

Q. In establishing the proposed initial capacity charge, is the Company assuming that any Choice customers are paying the capacity charge?

A. For purposes of determining the initial capacity charge, the Company is assuming that zero Choice load will take capacity service from DTE Electric beginning in 2018 since at this time we are unaware of any Choice customers who will be needing capacity. The Company is using the cost of service approved by the MPSC in its most recent rate case, Case No. U-18014 and PSCR costs reflected in the 2017 PSCR plan case. The rates established in Case No. U-18014 did not include the effects of any choice load taking capacity service from the Company. Since DTE Electric is using the approved cost of service associated with its power supply, the rates produced in this case will be revenue neutral with those approved in its last completed general rate case, Case No. U-18014. In other words, all bundled customers will pay the same amount, however, their generation rates will now be split between capacity and non-capacity costs.

Q. If some or all Choice load does take capacity service from the Company beginning in June 2018 will the Company realize a windfall of incremental revenue?

A. No. Under the provisions of PA 341, section 6 (w) (4) capacity revenue is to be reconciled each year. Thus, any incremental capacity revenue realized will be addressed in the annual capacity charge reconciliation and refunded to all customers paying the capacity charge.

Q. Can you describe the true-up associated with the capacity charge?

A. Yes. PA341 section 6w (4) provides for a true-up mechanism which will reflect the difference between projected net revenues associated with the capacity charge and actual net revenues.

Q. How does the Company propose that net revenues associated with the capacity charge be determined?

A. DTE Electric proposes that the true-up, or reconciliation of net revenues should reflect two components. Component One would reconcile the difference between forecasted capacity costs associated with purchase power, compared to the actual amount of capacity costs as approved by the Commission pursuant to the Company's PSCR reconciliation case for the same period. Component Two would reflect the difference between the forecasted amount of net energy market sales DTE Electric received pursuant to PA 341, section 6 (w) (3) (b) (i) through (iv), compared to the actual amount of net energy market sales as approved by the Commission pursuant to the Company's PSCR reconciliation case for the same period.

Q. PA 341 section 6w(3)b requires that the revenues from energy market sales, net of fuel costs, be subtracted from the costs that are recoverable through the capacity charge. How do you propose to calculate that net energy market revenue for reconciliation purposes?

A. Witness Wojtowicz addresses this calculation in her testimony.

Q. Is the capacity revenue true-up proceeding the proper venue in which to reconcile the difference between forecasted capacity costs associated with purchase power, compared to the actual capacity cost associated with purchase power and the net energy benefit?

A. No. The reconciliation of purchased capacity costs should take place in DTE Electric's annual PSCR reconciliation filing as it does today. The true-up mechanism as discussed in PA 341, section (4), would reflect the outcome of a final order in a PSCR reconciliation proceeding related to purchase power capacity cost and net energy market sales, and be reflected in the capacity cost true-up in the subsequent year.

Q. Does the timing of a PSCR reconciliation case match up with the timing of the capacity cost true-up case?

A. Yes. PSCR reconciliations are conducted on a calendar year basis, and the Company is proposing that the capacity charge reconciliation also be conducted on a calendar year basis, following the initial start-up.

Q. How frequently do you expect that the capacity charge will be modified by the Commission?

A. Generally, any base rate or PSCR factor change will change the capacity charge rates. Additionally, each year the Commission must conclude a proceeding by December 1 to review the capacity charge.

Q. In light of the December 1 required review you just addressed, when would you propose new capacity charge rates, pursuant to such a review, be implemented?

A. I propose that the capacity charge rates established by the Commission pursuant to the required December 1 review become effective on January 1st of the next year. There are costs and revenues in the capacity charge and the PSCR that are directly related. The PSCR operates on a calendar year basis, as such, administrative efficiency will be achieved by reflecting PSCR changes in the capacity charge on a calendar year basis and then reconciling them contemporaneously for that same calendar year.

Q. Does this complete 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 341 for	)	Case No. U-18248
DTE ELECTRIC COMPANY'S	)	
service territory.	)	

REBUTTAL TESTIMONY

OF

DON M. STANCZAK

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF DON M. STANCZAK

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Q. Please state your name, business address and by whom you are employed.

A. My name is Don M. Stanczak. My business address is One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Energy Corporate Services, LLC a subsidiary of DTE Energy as Vice President, Regulatory Affairs.

Q. Did you file direct testimony in this proceeding on behalf of the DTE Electric Company (DTE Electric or Company)?

A. Yes, I did.

Q. What is the purpose of your rebuttal testimony?

A. I am rebutting the testimony of Staff Witness Revere, ABATE Witness Dauphinais, Energy Michigan Witness Zakem and Constellation New Energy Witness Makholm relative to the determination of the Company's proposed capacity charge. I am also rebutting Staff Witnesses Cantin and Stocking and Energy Michigan Witness Campbell relative to various tariff provisions associated with the Company's proposed capacity charge.

Q. Are you sponsoring any exhibits in this proceeding?

A. No, I am not.

CAPACITY COSTS

Q. Generally, what has the MPSC Staff and the other parties proposed relative to determining costs that should be reflected in DTE Electric's capacity charge?

A. Generally, Staff and the other parties propose that a significant portion of the Company's embedded fixed generation cost be excluded from the capacity charge. In contrast the Company has proposed generally that all fixed or non-variable generation-related cost be reflected in the Company's capacity charge.

Q. On page 7 of his direct testimony, Staff Witness Revere states, "Staff's identification of capacity-related costs meets the requirements of 2016 PA 341 Section 6w(3), while the Company's does not, for the reasons laid out above." Do you agree with this statement?

A. No. On page 6 of his direct testimony, Witness Revere essentially indicates that generation cost may be segregated into the following *three* separate cost categories: *capacity-related*, *energy-related* and *non-energy costs*. Presumably the non-energy cost category could also be characterized as *non-capacity/non-energy* since he indicates that not all non-energy cost are capacity costs. However, Witness Revere never explains what differentiates capacity-related costs from non-capacity/non-energy costs. Thus, it is not possible to understand why Staff believes their interpretation of capacity cost is compliant with 2016 PA 341 Section 6w(3) ("PA 341"). In contrast, the approach the Company took in determining capacity costs, as explained in its direct testimony, is totally consistent with prior Commission rulings relative to establishing capacity costs. Moreover, the Company's approach to establishing capacity cost is also aligned with Staff's prior positions relative to the establishment of capacity costs. Finally, as explained more fully by witness Lacey, the Company followed NARUC principles from its Electric Utility Cost Allocation manual in determining the proposed capacity charges.

Q. You state that the Staff has taken prior positions relative to the establishment of capacity costs. Has the Commission established a capacity charge for any other Michigan utility in the past?

A. Yes. In Case No. U-17032 the Commission established capacity charges for Indiana Michigan Power Company (I&M). In its Order dated September 25th, 2012 in Case No. U-17032, the Commission approved a capacity charge for I&M, noting that the use of fully embedded costs was appropriate for setting a capacity charge, and that this treatment is consistent with Michigan's regulatory principles that are used for setting utility rates. The Order in Case No. U-17032 effectively approved the Staff's recommendation in that proceeding.

Q. What generation costs are included in I&M's capacity charge?

A. Essentially all demand related costs associated with I&M's generation assets are included in its capacity charge. According to I&M Witness Nancy Heimberger in Case No. U-16801 (the rate case that provided the cost of service relied on by the Commission to set the capacity charge in Case No. U-17032), demand costs are fixed costs that are incurred regardless of the level of energy sales. This is the same criteria that DTE Electric used in establishing its proposed capacity charge in this proceeding. That is, including essentially all fixed generation cost; those costs that do not vary with changes in sales.

Q. What was Staff's position in Case No. U-17032 relative to the appropriate cost to be included in I&M's capacity charge.

A. With one minor adjustment, Staff fully supported I&M's approach to determining capacity costs.

Q. Did Staff take any other notable positions in Case No. U-17032?

A. Yes. Consistent with the position several parties have taken in this case, including Staff, in Case No. U-17032 Energy Michigan argued that because of the Commission established a 75/25 generation allocation methodology, only 75% of fixed generation cost should be reflected in the capacity charge. In Case No. U-17032 Staff correctly observed that the 75/25 method "accurately and fairly allocates cost to classes so that similar customers are charged the same price for the same service." More importantly, in Case No. U-17032, Staff correctly asserted that if I&M's capacity rate was reduced by 25%, as recommended by Energy Michigan, Choice customers would only be paying for 75% of the capacity costs. (U-17032, September 25, 2012 Order page 21). Of course, PA 341 requires that the capacity charge does not differ for full service load and alternative electric supplier load. Therefore, based on Staff's own testimony in Case No. U-17032, Staff's proposal to reduce capacity costs by 25% in this proceeding would be inconsistent with the requirements of PA 341. Of course, the Commission order in Case No. U-17032 followed Staff's recommendation to not reduce fixed generation costs by 25% in establishing the I&M capacity charge. In fact, in the Case No U-17032 order, the Commission observed:

> "…..if the capacity rate is reduced by 25% as recommended by Energy Michigan, OAD customers will only be paying for 75% of capacity costs, while standard service customers will pay 100%. Such ratemaking is discriminatory and inconsistent with Michigan's ratemaking principles." (Case No. U-17032 order p. 30, dated September 25, 2012)

Thus, not only did the Commission agree with Staff relative to not reducing the capacity rate by 25%, the Commission also acknowledged that such a reduction would be discriminatory and inconsistent with Michigan rate making principles.

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Q. Did ABATE's Witness Dauphinais also propose that 25% of the Company's fixed capacity costs be removed from the capacity charge calculation?

A. Yes. On page 18 of his direct testimony, ABATE Witness Dauphinais proposed that the capacity costs that are allocated based on energy should be removed from the determination of the capacity costs in this proceeding. ABATE's proposed adjustment should be rejected for the same reasons that I cited for rejecting Staff's similar proposal.

Q. Was the I&M capacity charge established pursuant to PA 341?

A. No. The I&M capacity charge was established pursuant to the Reliability Assurance Agreement among load serving entities in the PJM Interconnection. More specifically, as provided by PJM's FERC approved tariff, the Commission initiated Case No. U-17032 to establish a State Compensation Mechanism (SCM) where alternative electric suppliers (AES's) compensate local utilities for capacity.

Q. Does the fact that the I&M capacity charge was established pursuant to a FERC approved SCM have any impact on the appropriate cost that should be reflected in a capacity charge?

A. No. Capacity costs are capacity costs. The method the Commission established in Case No. U-17032 is well reasoned, sound, and accurately reflects the full cost of providing capacity. Therefore, the same methodology for determining capacity costs should be applied in this proceeding.

Q. Did Staff Witness Revere make any other observation relative to the costs that should be included in or excluded from capacity costs?

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A. Yes. On page 5 of his direct testimony, Witness Revere states, "Costs incurred to supply capacity should be included as capacity-related costs. In Staff's opinion, the proper cost of capacity is the Cost of New Entry (CONE), or the cost to build a combustion turbine (CT)."

Q. Do you agree with Witness Revere that the proper cost of capacity is CONE?

A. No. 2016 PA 341 Section 6w(3)(a) requires that the capacity charge reflect costs included in the **utility's** base rates, surcharges and power supply cost recovery factors. That is, the capacity charge is to reflect actual costs that the utility experiences and is reflected in its rates. In contrast, CONE is an estimated theoretical amount relative to potential new generation and has no correlation with charges reflected in DTE Electric's base rates, surcharges and power supply costs.

As I stated earlier in my rebuttal testimony, it is appropriate to base a capacity charge on the Company's fully-embedded capacity costs, and that treatment is consistent with Michigan's principles for utility ratemaking.

Q. Does your rebuttal to Witness Revere's CONE argument apply equally to the similar argument proposed by Energy Michigan Witness Zakem on pages 42-44 of his direct testimony?

A. Yes.

Q. Does the Staff's approach to recovering their capacity related cost (Witness Revere's testimony on page 12), result in a revenue neutral position for the Company?

A. No. As further explained in the testimonies of Company witnesses Bloch, Holmes and Williams, Staff is proposing an entirely new way of recovering the Company's capacity related costs (during summer only and during MISO on-peak hours only) and made no attempt to adjust the Company's billing determinants to account for this radical change. This flaw in the Staff's rate design would change the Company's future revenue and thus the Company would not recover the approved requirement from Case No. U-18014. In addition, the Staff's approach would fundamentally change the way the vast majority of DTE Electric's customers are charged for electric service. This case is about unbundling the power supply rates into a capacity and non-capacity charge. Any proposals to alter the time periods in which rates are billed should be taken up in general rate case proceedings and be evaluated based on proper studies which identify how these changes impact customer usage and behavior. None of these issues have been supported by Staff in testimony or exhibits filed in this proceeding, and thus these proposals should be rejected by the Commission.

Q. Do you have any additional comments relative to the various reductions that Staff and the other parties made relative to their proposals to reduce the amount of cost reflected in the capacity charge?

A. Company Witness Mr. Lacey addresses in detail the flaws in each parties' proposed reductions to the Company's proposed capacity cost determination.

<u>**MPSC STAFF WITNESSES MS. CANTIN AND MR. STOCKING**</u>

Q. In your direct testimony you stated that any Electric Choice (Choice) customer that takes capacity service from the utility must continue to do so for a thirty-year period. At page 6 of her testimony Staff Witness Cantin states that the

Commission should reject this requirement since it violates PA 341. Do you agree with this suggestion?

A. No. When a customer takes capacity service from the Company, the Company is responsible for ensuring that the resources necessary to serve that customer's demand will be available. As I indicated in my direct testimony, capacity assets have long lives of thirty years or more, and it is appropriate to match the responsibility for the cost of service of those long-lived assets with the customers that cause those costs to be incurred. Further, if the duration of the capacity charge is not set for a long enough period, the required capacity necessary to serve all the State's customers may not be built, and or the continued subsidization of Choice customers by full service customers will be perpetuated. It is not appropriate to expect the Company to provide resource adequacy without the requisite resources, and the ability to recover the costs of those resources, therefore the Commission should reject the proposal to eliminate this tariff provision.

Q. DTE Electric included a tariff revision in its direct case that requires choice customers to notify the Company by April 1, 2018 if they will not be taking capacity service from the Company. At pages five to six of her direct testimony, Witness Cantin objects to this proposal because it is not normal to require a customer to notify the Company that they will not be taking service. Do you agree that this requirement should be rejected because it is different than past notification requirements?

A. No. The Company's notification requirement should not be rejected. It is worthwhile noting that the Company's retail Choice customer, if applicable, will be paying the capacity charge and not the (AES); the Company has no retail relationship with the

AES's. The key point here is that the Company will be providing capacity service to Choice customers and Choice customers will be paying the Company for that service. Relying on the AES to provide notification to the Company would essentially have the AES stand in the shoes of the Choice customer essentially signing up customers for an incremental service, namely capacity service provided by DTE Electric. The Company purposely designed this tariff provision with several key considerations in mind. First and foremost, to ensure that Choice customers know ahead of time whether their AES plans to procure capacity on their behalf. In addition, this provision should, to the extent possible, minimize any potential billing questions on the part of the Choice customer. That is, since the customer will have a role in notifying DTE Electric that the Company will be providing capacity service to the customers, the customer will be on notice that it will be billed for that service. Finally, requiring Choice customers to notify the Company should also address potential proration issues where an AES is providing a portion, but not all, the capacity to collectively serve its customers. For example, if an AES is providing 50% of the capacity needed to serve its customers, DTE Electric needs to know which specific customers' capacity requirements will be provided by the AES. The tariff notification process proposed by the Company will ensure that customers and the Company know in advance if the customers' capacity service will be supplied by DTE Electric. For these reasons, it is imperative that the Choice customers play a central role in establishing the level of capacity service required from DTE Electric.

Q. On page 7 of her direct testimony Witness Cantin states: "The Company should not be permitted to shift the burden from the AES, which is required to notify the Company if it will not be able to satisfy its capacity obligation, to place an

even heavier burden on the AES customer." Do you agree that this proposed tariff requirement would shift the demonstration requirement included in PA 341 from the AES to its customers?

A. No. The Company's proposed notification requirement does not shift any capacity demonstrations between any parties. The obligation of the AESs to demonstrate their ability to provide capacity to the Commission would not change. It is important to distinguish between capacity demonstration and cost responsibility. The AES has the demonstration responsibility while the "load" or Choice customer is responsible to pay the capacity charge. The Company's tariff defines the terms and conditions under which it provides service to its retail customers, none of whom are AES's. This proposed notification requirement is necessary for the Company to plan to serve its customers' resource adequacy needs and then to bill its customers for that service. Absent the Company's notification provision, administration of the tariff would be unworkable. For the foregoing reasons, the Commission should accept the Company's notice provision.

Q. Does the Staff support the Company's proposal to place Choice customers taking utility capacity service on an interruptible tariff in the event that there is insufficient capacity available to serve them on a firm basis?

A. No. Both Witness Cantin and Staff Witness Stocking object to the Company's proposal to place Choice customers taking utility capacity service on an interruptible tariff in the event that there is insufficient capacity available to serve them on a firm basis. Moreover, on pages 8 and 9 of his testimony, Witness Stocking seems to be justifying Staff's position by arguing that MISO Zone 7 will likely not be short of capacity in the near term and that a Choice customer returning to utility capacity service will not create a capacity short-fall in MISO Zone 7. However, there is a real possibility that at some point in the future there may be a capacity short-fall in MISO Zone 7. Further, should such a capacity short-fall occur in MISO Zone 7 in the future, that would seem a likely time that Choice customers would be seeking capacity from DTE Electric. Therefore, under such a circumstance, pursuant to DTE Electric's interruptible proposal, the returning Choice customer would not create a capacity short-fall for DTE or MISO Zone 7, thus protecting DTE Electric's existing customers' service quality. Because a capacity shortage is possible the Company must have the ability to place returning Choice customers on interruptible capacity service if firm capacity is unavailable.

Q. Does Staff explain how the Company should proceed if, in what they described as an unlikely event, the Company is unable to acquire the capacity resources necessary to serve on a firm basis all Choice load that is requesting firm capacity service from the Company?

A. No, Staff does not.

Q. Were the Commission to reject this tariff provision to serve Choice customers on an interruptible basis if there is not sufficient capacity to serve that load, what would you expect would happen?

A. In that event, I would expect that the returning Choice load would be placed on firm service, and then due to the insufficient availability of capacity to serve the Company's capacity requirements, the service reliability for **all** customers would decline.

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ENERGY MICHIGAN WITNESS CAMPBELL

Q. At page five of his direct testimony Witness Campbell claims that the Company's requirement that Choice customers notify the Company by April 1st, 2018 if they will not need capacity service from the Company essentially transfers the MPSC's role to verify AES's capacity demonstrations to the Company. Do you agree with this claim?

A. No. Witness Campbell's claim that the Company is assuming the Commission's capacity verification role is incorrect. As I explained in my previous rebuttal to Witness Cantin on this topic, the obligation of the AESs to demonstrate their capacity to the Commission would not change. The Company's tariff defines the terms and conditions under which it provides service to its customers, and this proposed notification requirement is necessary for the Company to plan to serve its retail customers' resource adequacy needs and then to bill its customers for that service. Additionally, the entirety of the terms and conditions under which the Company provides service to its customers are not codified in PA 341.

Q. Do you agree with Witness Campbell's claim that the Company's notification requirement is unjust and unreasonable?

A. No. As I stated earlier, DTE Electric needs to know which customers it will be providing capacity service to acquire the resources necessary to provide that service and to ensure it is afforded sufficient time to establish proper billing mechanisms.

Q. Witness Campbell states on page seven of his testimony that should an AES only provide a portion of its capacity, then DTE Electric should bill the AES for the balance, and not the AES's customers. Is this proposal acceptable?

A. No. As I indicated earlier in response to Staff, we do not provide retail electric service to the AESs, nor should we start. PA 341 requires that the "load" or customer is subject to the capacity charge. For these reasons it would be inappropriate to bill the AES the capacity charge.

ENERGY MICHIGAN WITNESS ZAKEM

Q. On page 23 of his direct testimony Energy Michigan Witness Zakem states that a capacity charge should be based on the cost of acquiring capacity and not the Company's costs of its existing generation. Is Witness Zakem correct?

A. No. As stated earlier in my rebuttal testimony to Witness Revere, the Commission has already determined that the use of fully embedded costs is appropriate for setting a capacity charge, and that this treatment is consistent with Michigan's principles for setting utility rates. Witness Zakem's proposal is not consistent with those principles so it must be rejected.

Q. On pages 40 through 51 of his direct testimony Witness Zakem describes his SRM proposal under which the costs of new capacity resources in DTE Electric's service territory would be paid for by all load, not just DTE Electric's bundled load. In your opinion is his proposal acceptable?

A. Witness Zakem's SRM proposal is unacceptable. As I have stated several times, DTE Electric's capacity rates are appropriately set based on its fully embedded costs, and Witness Zakem's proposal to only share the costs of new generation resources would contradict that policy and would discriminate against the Company's bundled customers who would end up shouldering the bulk of capacity costs.

CONSTELLATION NEW ENERGY WITNESS MAKHOLM

Q. Constellation New Energy Witness Makholm claims at page 10 of his direct testimony that DTE Electric's proposed capacity charge includes costs that are not capacity-related. Is Witness Makholm correct?

A. No. Witness Makholm's assertion that the Company's capacity charge includes costs that are not capacity related is incorrect. The Company's capacity charge is based on the Cost of Service Study (COSS) performed by the Staff of the Michigan Public Service Commission at the conclusion of the Company's last general rate case, Case No. U-18014. The purpose of a COSS is specifically to classify costs as capacity, energy, and customer related. DTE Electric's capacity costs were calculated by Company Witness Lacey by taking the Company's total cost of production and removing costs that were related to energy. The result of that calculation was the Company's fully embedded cost of capacity, which contrary to Witness Makholm's claims, is the appropriate basis for setting DTE Electric's capacity charge.

Q. You stated that Witness Makholm claimed that there were costs included in DTE Electric's capacity COS that are not capacity-related. Did he provide any specific examples of such costs?

A. No, he does not.

Q. On page 18 of his direct testimony, Witness Makholm suggests that the Commission require the Company to perform a planning model calculation when it submits future capacity charges for approval. Are the Company's current rates that recover its capacity costs based on a planning model calculation?

A. No. The Company's current rates that recover its capacity costs are based on the fully embedded costs of its capacity resources.

Q. Can you summarize the Company's position with respect to the multitude of capacity cost assignment schemes that various interveners have developed?

A. Yes. PA 341 Section 6w(3)(a) requires that the capacity charge reflect costs included in the **utility's** base rates, surcharges and power supply cost recovery factors. Capacity costs should not be based on: (1) CONE (as suggested by Staff); (2) an arbitrary 75/25 allocation method (Staff & ABATE); (3) cost of new capacity only (Energy Michigan); (4) vague claims the Company has unrelated costs included in the capacity charge (Constellation); or (5) the "average and excess method" (Constellation). While these are all interesting theories, they are only meant to inappropriately reduce the Company's actual embedded capacity cost according to its most recent approved general rate case. Thus, they should be rejected as inconsistent with PA 341.

Q. Does this complete your rebuttal testimony?

A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for Authority to Implement the	)	Case No. U- 18248
provisions of Section 6w of 2016 PA 341	)	
for the Company's service territory	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

TIMOTHY A. BLOCH

DTE ELECTRIC COMPANY
QUALIFICATIONS OF TIMOTHY A. BLOCH

Q. Will you please state your name, business address and by whom are you employed?

A. My name is Timothy A. Bloch. My business address is: One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Energy Corporate Services, LLC within Regulatory Affairs as Principal Financial Analyst.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of DTE Electric Company (DTE Electric or Company) formerly, the Detroit Edison Company (Detroit Edison).

Q. What is your educational background?

A. I graduated from Michigan Technological University in 1980 with a Bachelor of Science degree in Mechanical Engineering.

Q. Have you completed any other courses of study?

A. Yes, I have completed several professional level training courses including Power Systems Engineering, P.U.R. Guide course, Fundamentals of Economic Analysis, Public Utility Accounting, AEIC Fundamentals of Load Research, AIC Negotiating Power Supply Contracts, Sampling Methods & Statistical Analysis in Power Systems Load Research, EEI Rate Fundamentals course, EEI Advanced Rate course and others.

Q. What work experience do you have?

A. I joined Detroit Edison in 1981 as an Assistant Engineer in the Central Heating Plants of the Production Organization. I was responsible for equipment performance and

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efficiency testing, system troubleshooting, outage management and capital improvement projects.

In 1984, I accepted a position as an Associate Engineer with the District Heating Management Organization. My responsibilities in this position included financial reporting, preparing testimony for the steam cost recovery cases and providing technical assistance to the sales and service staff. In addition, I provided technical recommendations and managed several engineering and economic projects related to the design, expansion, operation and maintenance of the steam distribution system and customer service installations. During this time, I was promoted from Associate Engineer to Engineer and in 1988 from Engineer to Senior Engineer.

In 1989, I cross-trained in the Customer Options Group of Marketing. In this position I assisted in the administration of Detroit Edison's power purchase contracts with FERC-qualified facilities. In 1990 I accepted a permanent position in this group.

From 1990-1994, my primary responsibility was to assist in the development and negotiation of waste-to-energy contracts resulting from Public Act 2 (PA2). I was directly involved in developing the terms and conditions for these contracts, meeting with and providing information to customers and developers interested in developing PA2 projects, and representing the Company in the negotiation process. I was also the Company's witness in the filing of PA2 contracts.

In 1994, after the Company went through a restructuring process, Customer Options became part of the Pricing group and my job title changed to Analyst/Pricing.

From 1994 to 1998, my primary responsibilities in Pricing included contract administration of PA2 contracts, rate analysis and design, and support in the development of special contracts, such as the Special Manufacturing Contracts (SMC) and the Large Customer Contracts (LCC). During this period, I also cross-trained for approximately one year with our Load Research group to learn statistical sampling techniques, methods of accessing customer data and how the Total System Analysis (TSA) is performed. In June 1998, I was promoted to Principal Financial Analyst. My current responsibilities include the development of residential, commercial, industrial, and governmental rates. I am also responsible for developing and recommending pricing policy and development, application and administration of rate tariffs, as well as the rules and regulations governing service.

Q. Have you testified previously before the Michigan Public Service Commission?

A. I have sponsored testimony in the following cases:

U-18091	PURPA Avoided Costs Filing
U-18014	DTE Electric General Rate Case
U-17767	DTE Electric General Rate Case
U-17734	In the matter of the Formal Complaint of AK Steel Corporation (successor to Severstal Dearborn, LLC) against DTE Electric Company for standby service.
U-17689	DTE Electric Public Act 169 of 2014 Filing
U-17251	DTE Electric Amendment to Rider No. 3
U-16472	DTE Electric General Rate Case
U-16384	U-15768 Self Implementation Refund
U-15768	Detroit Edison General Rate Case

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U-15244	Detroit Edison General Rate Case
U-11452	Detroit Edison Direct Access Tariff
U-10066 – U10070	1989 PA2 Power Purchase Agreements
U-10232	1989 PA2 Power Purchase Agreement

DTE ELECTRIC COMPANY
DIRECT TESTIMONY OF TIMOTHY A. BLOCH

Line No.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to develop and support the Company's proposed power supply capacity charges and tariff language modifications for the primary rate schedules and the proposed tariff changes to the Retail Access Service Rider - EC2 pursuant to the requirements of Section 6w 2016 PA 341.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits:

Exhibit	Schedule	Description
A-11	1	Revenue Neutral Comparison of Present (U-18014) and Proposed revenues
A-11	2	Present (U-18014) and Proposed Rate Designs by Rate Schedule
A-12	1	Proposed Tariff Sheets
A-12	2	Redline Version of EC2

With respect to Exhibit A-11, Schedule 2, I am sponsoring the Commercial and Industrial (C&I) primary rate classes, which includes pages 24 through 38 of this exhibit. Company Witnesses Ms. Holmes and Mr. Williams are sponsoring the remaining customer classes in Schedule 2. On Exhibit A-12, Schedule 1, I am sponsoring the proposed tariff changes related to the C&I primary tariffs and tariff changes to the Retail Access Service Rider - EC2 (EC2). Witnesses Holmes and Williams are sponsoring the remaining sheets contained in this exhibit. Exhibit A-12, Schedule 1 includes a "clean" version of the proposed language changes to EC2. On Exhibit A-12, Schedule 2, I have included a "redline" version of the proposed language changes to EC2.

Q. Were these exhibits prepared by you or under your direction?

A. Yes, they were.

Q. Why did you include both a “clean” version and a “redline” version of EC2?

A. Given the number of proposed changes to EC2, I thought it would be easier to read the “clean” version of the tariff as part of Exhibit A-12, Schedule 1. For those wanting to see how the changes compared to the current EC2 tariff, I performed a document compare between the proposed clean version of EC2, with the current version of EC2 from DTE Electric’s tariff. Although it’s admittedly a little difficult to read, the resulting “redline” version (Exhibit A-12, Schedule 2) shows the proposed changes, which includes new language, deleted language, and sections which were moved.

Q. How were the capacity and non-capacity charges determined for the primary rate schedules?

A. 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.

The capacity and non-capacity charges proposed in this case are designed such that every bundled customer would receive the same total rates and bill amount before and after the change. To illustrate this, the below table shows how the Rate Schedule D11 rates for bundled customers are the same before and after the proposed changes.

Rate Schedule D11 Power Supply Rates: Current versus Proposed

Line No	Power Supply		
1	**Capacity Charges**	**Current**	**Proposed**
2	Power Supply Demand	$15.79/kW	$15.79/kW
3	On-Peak Energy	4.330 ¢/kWh	1.372 ¢/kWh
4	Off-Peak Energy	3.330 ¢/kWh	0.372 ¢/kWh
5	Voltage Level Discount		
6	Subtransmission	-0.141 ¢/kWh	-0.025 ¢/kWh
7	Transmission	-0.214 ¢/kWh	-0.037 ¢/kWh
8			
9	**Non-Capacity Charges**		
10	All Energy	N/A	2.957 ¢/kWh
11	Voltage Level Discount		
12	Subtransmission	N/A	-0.116 ¢/kWh
13	Transmission	N/A	-0.177 ¢/kWh
14			
15	**Total Power Supply Charges**	**Current**	**Proposed**
16	Power Supply Demand	$15.79/kW	$15.79/kW
17	On-Peak Energy	4.33 ¢/kWh	4.33 ¢/kWh

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18	Off-Peak Energy	3.33 ¢/kWh	3.33 ¢/kWh
19	Voltage Level Discount		
20	Subtransmission	-0.141 ¢/kWh	-0.141 ¢/kWh
21	Transmission	-0.214 ¢/kWh	-0.214 ¢/kWh

Q. How do the Company's proposed power supply charges impact revenues?

A. The Company's proposed rate design is revenue neutral compared to the current rates approved by the Commission on January 31, 2017. The present and proposed revenue by rate schedule and by function (Power Supply and Distribution) do not change as a result of the Company's proposed power supply rates. On Exhibit A-11, Schedule 1, I have summarized the present and proposed revenues by rate schedule for the 12- month period ending July 31, 2017. Present revenues are based on rates approved by the Michigan Public Service Commission on January 31, 2017 in the Company's last general rate case, Case No. U-18014. The exhibit provides a revenue neutral comparison of total present and proposed revenues on page 2, present and proposed power supply revenues on page 3, and present and proposed distribution revenues on page 4. The proposed power supply revenues on page 3 provide a separate breakout of capacity and non-capacity related power supply revenues.

Q. What other details are you presenting with respect to rate design?

A. On Exhibit A-11, Schedule 2, I compare the present and proposed rate design and corresponding revenue by rate schedule using the same billing determinants used to design final rates in Case No U-18014. The exhibit details the billing determinants, and corresponding present and proposed rates and revenue. The various billing components are listed in column (a), and the respective billing determinants, including units of measure, are listed in column (b). The existing rates, as approved in Case No. U-18014, are in column (c), and are used to calculate the present revenues in column (d). The proposed revenue neutral rates which include capacity and non-capacity related power supply charges are in column (e), with the resulting revenues in column (f). This filing does not impact any delivery related charges or delivery revenue approved by the commission in Case No. U-18014.

Q. How will the capacity and non-capacity charges be applied to bundled and Retail Access customers?

A. As supported and instructed by Company Witness Mr. Stanczak, Exhibit A-11, Schedule 2 shows that bundled customers will be charged both the capacity and non-capacity power supply charges, while only the power supply capacity charges will be applicable to Retail Access customers taking capacity service from DTE Electric. As Witness Stanczak, supports in his testimony in this case, and reflected in this exhibit, the Company is assuming that no Retail Access customers will take capacity service from the Company.

Q. What specific tariff changes is the Company proposing in this case?

A. On Exhibit A-12, Schedule 1, I have included proposed tariff sheet changes which: 1) separate bundled power supply charges into capacity and non-capacity related charges and corresponding price changes; 2) include capacity related charges for retail access service customers taking capacity service from the Company; 3) address changes to the Retail Access Service Rider – EC2, and; 4) adds a separate interruptible capacity limit to Interruptible Supply Rate – D8 applicable to Retail Access customers returning to full service or taking Utility Capacity Service Interruptible Supply Rate-D8.

Q. What changes are you proposing to make to Retail Access Rider-EC2?

A. 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

Q. How do the tariff modifications address conditions where there is insufficient capacity available to provide firm service to Retail Access customers electing Utility Capacity Service or returning to Bundled Service?

A. If the Company cannot procure sufficient capacity to provide firm service to Retail Access customers electing Utility Capacity Service, or returning to Bundled Service, then the Company will establish a firm service queue and customers will be placed on interruptible rates in the interim. As discussed by Company Witness Ms. Wojtowicz, the customer will be placed in the queue based on their return month, which is the month the customer will begin taking capacity service from DTE Electric. For customers with the same return month, placement in the queue will be based on receipt of request date/time. Customers in the queue will be placed on interruptible service tariffs until Firm Service becomes available through the queue. Interruptible service under the queue shall not exceed four years at which the the customer will be eligible for Firm Service. Customers who provide four years advance notice to return to Bundled Service or take Utility Capacity Service will be provided Firm Service at the time of their return month.

Q. If a Retail Access customer gives the Company four years advance notice of return, how is the Company able to provide firm service?

A. As discussed by Witnesses Stanczak and Wojtowicz, four years advance notice will allow enough time for the Company to build, develop, or procure capacity.

Q. Will Retail Access customers electing capacity service be treated the same as Retail Access customers returning to bundled service under the queue?

A. Yes.

Q. What tariff changes are you proposing related to the notice requirements for Retail Access customers electing Utility Capacity Service or returning to Bundled Service?

A. The proposed return to Bundled Service and Utility Capacity Service notification requirements are shown in Sections E4.2.1 and E4.2.2 on Exhibit A-12, Schedule 1. Under the Company's proposal, Customers returning to Bundled Service or taking Utility Capacity Service must provide irrevocable written notice not less than 3 days prior to the next scheduled billing cycle for which Bundled Service or Utility Capacity Service is to commence. The proposed notification requirements replace the notification requirements in Section E5.3A of the current tariff.

Q. What tariff changes are you proposing related to the minimum term for Retail

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Access customers returning to Bundled Service or taking Utility Capacity Service?

A. As supported by Witness Stanczak, Retail Access customers returning to Bundled Service or taking Utility Capacity Service will be required to take capacity service from the Company for 30 years. I have included this requirement in Sections E4.2.1 and E4.2.2 of the Company's proposed tariff and removed Section E5.3B of the current tariff to conform with this proposed change.

Q. After June 1, 2018, if the Company's Retail Access cap falls below 10%, and bundled customers elect Retail Access Service, what is the minimum term for remaining a customer of the AES?

A. The Company has removed all the minimum term, or "stay out" provisions after the effective date of this tariff.

Q. If a Retail Access customer returns to bundled service prior to the effective date of this tariff (e.g., December 1, 2017), will they be provided firm capacity service?

A. Yes. This treatment is consistent with current practice.

Q. Why are you proposing to add a separate interruptible capacity limit to Interruptible Supply Rate – D8 applicable to Retail Access customers returning to Bundled Service or taking Utility Capacity Service Interruptible Supply Rate-D8 effective on and after December 1, 2017?

A. As discussed above, if the Company is unable to reasonably procure sufficient capacity resources to provide firm service to Retail Access customers returning to

Bundled Service or taking Utility Capacity Service, then the Company is proposing to place these customers on interruptible rates until capacity resources become available to provide firm service. For primary Retail Access customers returning to Bundled Service after December 1, 2017, or taking Utility Capacity Service, that interruptible service will be provided under the Interruptible Supply Rate – D8. Rate D8 is limited to 300MW of contracted interruptible capacity with approximately 150MW currently available. Since the Company does not know how many primary Retail Access customers may elect Utility Capacity Service or to return to Full Service, or the availability of capacity to serve these customers, the remaining 150MW of D8 capacity may not be sufficient to meet this potential requirement. To address this concern and leave the remaining capacity available to current bundled customers, the Company is proposing a separate D8 capacity limit for primary Retail Access customers electing Utility Capacity Service or returning to Bundled Service. This capacity limit will be available on an experimental basis for 4 years beginning June 1, 2018, with a contracted interruptible capacity limit of 1000MW. This experimental limit will provide sufficient interruptible capacity to meet this potential requirement over the first four years. See Exhibit A-12, Schedule 1 – Rate Schedule D8. Witness Holmes discusses changes to the Company's secondary interruptible rate D3.3.

Q. Does this complete 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 341 for	)	Case No. U-18248
DTE ELECTRIC COMPANY'S	)	
service territory.	)	

REBUTTAL TESTIMONY

OF

TIMOTHY A. BLOCH

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF TIMOTHY A. BLOCH

Line
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Q. What is your name, business address and by whom are you employed?

A. My name is Timothy A. Bloch. My business address is One Energy Plaza, Detroit, MI 48226-1221. I am employed by DTE Energy Corporate Services LLC within Regulatory Affairs as Principal Financial Analyst – Regulatory Economics.

Q. Did you file direct testimony in this proceeding on behalf of DTE Electric Company (DTE Electric or Company)?

A. Yes, I did.

Q. Are you sponsoring any exhibits along with your rebuttal testimony?

A. No, I am not.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to rebut the Michigan Public Service Commission Staff (Staff) proposed primary rate design and rebut the position of Kroger Witness Mr. Townsend regarding his testimony on the proper billing units for any capacity charge applied to customers.

Q. On Page 12 of Staff Witness Mr. Revere's direct testimony, he states, "Staff recommends that capacity-related costs be collected through summer on-peak kWh charges for rate schedules without demand charges, and through summer on-peak kW charges for rate schedules with demand charges." How do you respond to the ratemaking policy portion of Mr. Revere's testimony?

A. Staff's proposed industrial rate design is inappropriate and fundamentally flawed because it does not support a revenue neutral outcome. Radically altering the on-peak billing demand collection period from 12 months to the 4 summer months and changing the current daily 8 hour on-peak period to the MISO 16 hour on-peak period is a very risky proposition, considering almost 50% of industrial power supply revenues are collected through on-peak billing demand. Of primary concern is how to develop the billing determinants to estimate changes in customer operating behavior and migration to other rates for such a significant change. For large industrial customers, movements between D11 and R10 can be very significant. In my opinion, Staff's proposed radical change cannot be accomplished within the current case and still maintain such revenue neutrality. Further, such a radical change should not be attempted all at one time but should be implemented gradually after review in a general rate case proceedings. Specifically, any proposals to change on-peak billing demand collection periods for primary rates require a much more gradual approach because customers have been conditioned to the current billing demand collection method for decades. In addition, the over and under collection risks involved with such a significant portion of primary customer power supply revenues should not be undertaken without careful consideration of the affected customers and their ability to change behavior and/or change rates.

Q. How do you respond to the rate design aspects of Mr. Revere's testimony?

A. Staff provides no analysis or support for its recommendation to change the billing demand period. In addition, Staff's proposed primary rate design does not include its recommendation to change the billing demand period as recommended in its testimony. Staff's proposed primary rate designs utilized the 12-month billing demand determinants as opposed to the 4 summer months recommended in their testimony and therefore Staff's proposed primary rate designs should be rejected.

Q. Do you agree with Kroger Witness Townsend's position beginning on page 5 (line 13) that billing demands for a retail open access customer who is paying a capacity charge to the Company should be based on the individual customers aggregated demand across its various sites?

A. No. Witness Towsend is attempting to bring up an issue, load aggregation, that was previously rejected after consideration by the Michigan Public Service Commission (Commission) in its December 11, 2015 Order in Case No. U-17767 and has no place in this proceeding.

Q. Can you provide some background on the Commission's Order in Case No. U-17767 related to load aggregation?

A. In DTE Electric's general rate case (U-17767), the Company proposed to eliminate the Experimental Load Aggregation Pilot (ELAP) on grounds that the program, which allows primary customers with multiple sites to aggregate their power supply billing demands, was not cost-based and therefore results in intra-class subsidies. Kroger objected to DTE Electric's proposal and argued that instead of eliminating the ELAP, it should be found to be cost-based, and it should be made permanent. The Commission agreed with the Company and found that "*the record supports the elimination of the ELAP due to the intra-class subsidies created by this rate. Specifically, the Commission concurs with Mr. Bloch who pointed out, "The fact that the ELAP does nothing to alter the Company's costs or the allocation of costs to cost of service classes and yet reduces rates paid by ELAP customers is proof that the ELAP is not cost based." 4 Tr 569. Accordingly, the Commission finds that the ELAP should be terminated.*" (Order at page 128).

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The capacity charge, which is the billing demand charge for retail open access customers is applied to retail open access customers the same as full service customers, and does not allow load aggregation.

Q. Can you explain why this issue has no place in this proceeding?

A. Any consideration of load aggregation in this case is not appropriate since any level of acceptance by the Commission would result in cost shifts to other customers and disrupt the revenue neutrality of the rates approved by the Commission in Case No. U-18014. If Kroger desires to re-litigate this same issue again, which the Commission recently and decisively ruled in Case No. U-17767, the appropriate forum would be in the Company's general rate proceeding.

Q. Does this complete your rebuttal testimony?

A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the Matter of 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	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

PHILIP W. DENNIS

DTE ELECTRIC COMPANY
QUALIFICATIONS OF PHILIP W. DENNIS

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Q. Please state your name, business address and by whom you are employed.

A. My name is Philip W. Dennis. My business address is One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Energy Corporate Services, LLC, a subsidiary of DTE Energy Company as Manager, Regulatory Economics.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of DTE Electric Company (DTE Electric or Company).

Q. What is your education background?

A. I received a Bachelor of Science Degree in Business Administration from Central Michigan University. In addition, I received a Master of Finance Degree from Walsh College.

Q. What work experience do you have?

A. In 1981 I was employed by ANR Pipeline Company (ANR) as a Finance Trainee. ANR is an interstate natural gas (gathering, storage and transmission) company regulated by the Federal Energy Regulatory Commission (FERC). I had varying and increasing responsibilities within ANR, including positions in their Controller's organization, Regulatory Affairs and Marketing groups. While working in the Regulatory Affairs organization, I assisted in the preparation and analysis of general rate cases, purchased gas adjustments, and various surcharge recovery filings. While in Regulatory Affairs, I presented testimony at the FERC sponsoring various cost of service components and participated as a witness in ANR's rate case hearings. In 1994 I was promoted to Manager of Transportation Rates. I transferred to ANR's Marketing department in 1999 as Manager of Market Analysis. I remained there until

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early 2001, when ANR, as part of a merger, was moved to Houston and I left the Company. In 2001, I began working for Michigan Consolidated Gas Company (MichCon) as a Principal Financial Analyst in the Regulatory Affairs department. In 2001, MichCon's parent, MCN Energy, was acquired by DTE Energy, DTE Electric's (formerly The Detroit Edison Company) parent. In 2005, I was promoted to Regulatory Affairs Consultant and was project manager for DTE Electric's general rate cases Case Nos. U-15244, U-15768 and U-16472. In 2011, I assumed my present position of Manager, Regulatory Economics.

Q. What are your current duties and responsibilities with DTE Electric?

A. My responsibilities include the management of regulatory activities relative to DTE Electric's Load Research, Tariffs, Pricing, and Rate Design.

Q. Have you previously sponsored testimony before the Michigan Public Service Commission (MPSC or Commission)?

A. Yes. I sponsored testimony in Case No. U-17437, DTE Electric's transitional cost recovery plan associated with the disposition of the City of Detroit Public Lighting System. I also sponsored testimony in Case No. U-17761, DTE Electric's first reconciliation of the Transitional Reconciliation Mechanism associated with the disposition of the City of Detroit Public Lighting System for the period August 1, 2013 through December 31, 2014. I sponsored testimony in Case Nos. U-18005 and U-18251, DTE Electric's Transitional Recovery Mechanism reconciliation for the calendar years 2015 and 2016, as well.

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Q. What is the purpose of your testimony in this proceeding?

A. My testimony will identify the various capacity related filings required as a result of Public Act 341 (PA 341) and lay out a timeline of anticipated filing dates.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring the following exhibit.

Exhibit	Description
A-16	Examples and Timing of Capacity Related Filings

Q. Was this exhibit prepared by you or under your direction?

A. Yes, it was.

Q. Can you describe briefly the filings related to capacity charges required as a result of PA 341?

A. It is my understanding that PA 341 requires the Commission to review capacity charges not less then once a year, and in all rate cases, power supply recovery filings (PSCR), or separate proceedings. It is also my understanding that each capacity charge proceeding must conclude by December 1 of each year. Company Witness Mr. Stanczak describes the interaction of the capacity filings, with the PSCR and how the capacity true-up will be calculated.

Q. How many filings would the Company be making annually to meet the requirments of PA 341?

A. I believe there would be at least three filings, a PSCR filing, a capacity plan filing, and a capacity charge true-up filing.

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Q. How would these three filings interact with the initial capacity plan filing?

A. Exhibit A-16, reflects both capacity related cost filings, and filings associated with the PSCR between now and June 2020. Line 1 shows the initial capacity plan filing (U-18248) with a final order by December 1, 2017, with rates effective June 1, 2018 as required by PA 341. Line 2 reflects the Company's 2018 PSCR Plan filing on September 30, 2017. Based on the 2018 PSCR Plan filing, DTE Electric anticipates that it will file an update to its proposed June 1, 2018 capacity rates to reflect the most recent purchase power capacity costs as identified in the September 30, 2017 PSCR Plan filing (line 3) and net energy benefit amount. These rates will need to be approved no later than May 26, 2018, so that the capacity charges can be effective beginning June 1, 2018. Line 4 reflects the 2019 Capacity Plan filing, with expected Order date of December 1, 2018, for rates effective beginning January 1, 2019. DTE would again file a PSCR Plan case on September 30, 2018 (line 5) with updated purchase power capacity costs and net energy market sales. These amounts would then be used in determination of the capacity rates effective January 1, 2019. Line 6 reflects the PSCR Reconciliation filing where both the purchase power capacity and net energy market sales true-up amounts for 2018 will be determined. Line 7 reflects the 2020 Capacity Plan filing, with expected Order date of December 1, 2019, for rates effective beginning January 1, 2020. DTE would again file a PSCR Plan case on September 30, 2019 (line 8). Finally, as shown on Line 9, the Company will file both its Capacity Plan and True-up case on June 1, 2020. The Capacity Plan would be for rates effective January 1, 2021. The True-up portion would cover the period June 1, 2018 through December 31, 2018, which was the Company's initial period in which the capacity charge is expected to be in place. The process would then repeat annually in subsequent years.

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Q. Do your examples include any general rate cases in which the Company may file?

A. No it does not.

Q. How would a general rate case filing which will include new capacity charge calculations affect the timing of the filings you described?

A. If the Company were to file a general rate case, then the annual capacity filings shown in my examples will likely not be necessary since a general rate case should qualify as the annual capacity filings contemplated by PA 341.

Q. What is the interplay between the annual filings which set the capcity charge and the Company's annual true-up filing?

A. As shown on Exhibit A-16, the Company proposes to file its true-up as part of the annual Capacity plan proceeding, which would be in June of each year. Of course this timing is dependent on the Orders received in the Company's PSCR Reconciliation filings, since the Company believes that the PSCR reconciliation proceedings are the proper venue to determine the capacity charge true-up amounts. Adding the capacity charge true-up to the PSCR reconciliation case will provide the Commission time to review the true-up report and Capacity plan case as part of a contested case and issue an order in time for the over or under recovery to be included in the subsequent year's capacity charge.

Q. In your example above, the initial capacity charge is effective June 1, 2018 through December 31, 2018. However, you do not anticpate flowing through the true-up associated with this billing period until January 1, 2021. Why does it

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take so long to true-up the initial capacity charge ?

A. As discussed by Witness Stanczak, the proper venue for reconciling both the purchase power capacity costs and the net energy market sales, is the annual PSCR reconciliation cases. For DTE Electric, we file these cases annually by March 31, for reconciliation of the preceeding year. In my example, the 2018 PSCR reconciliation, as shown on line 6, is filed by March 31, 2019. Based on recent history, the Company would most likely receive a final order approximately 12 months later (i.e. March 31, 2020). Therefore, pursuant to PA 341, we would reflect the true-up in the "subsequent year" capacity charge. Thus, as shown on line 9, we would roll in any over or under amounts as part of our June 1, 2020 filing, with expected order by December 1, 2020, with rates effective January 1, 2021. Of course if the the PSCR reconciliation case were to conclude earlier, then this filing time line could change accordingly.

Q. Does this conclude your direct testimony?

A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the Matter of 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	)	

REBUTTAL TESTIMONY

OF

PHILIP W. DENNIS

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF PHILIP W. DENNIS

Line
No.

Q. Please state your name, business address and by whom you are employed.

A. My name is Philip W. Dennis. My business address is One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Energy Corporate Services, LLC, a subsidiary of DTE Energy Company as Manager, Regulatory Economics.

Q. Did you file direct testimony in this proceeding on behalf of DTE Electric Company (DTE Electric or Company)?

A. Yes, I did

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes I am sponsoring the following exhibit.

Exhibit	Description
A-21	Example of Purchase Power Capacity Reconciliation

Q. Was this exhibit prepared by you or under your direction?

A. Yes it was.

Q. What is the purpose of your rebuttal testimony?

A. Michigan Public Service Commission Staff (Staff) Witness Mr. Revere stated in his direct testimony (beginning on page 13, line 28) that he supports the Company position that capacity-related costs associated with purchase power continue to be reconciled in the Power Supply Cost Recovery (PSCR) Reconciliation cases, but stated that more specificity around the proposal would benefit the Commission's decision making process.

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Q. Can you provide more specificity with respect to DTE Electric's proposal that Mr. Revere stated was missing from DTE's proposal?

A. Yes. I provided a description of the interaction of capacity charge, base rate and PSCR cases in my direct testimony along with a timeline on my Exhibit A-16. Company Witness Mr. Stanczak describes the capacity true-up in detail as part of his direct testimony (beginning on page 18, line 16), however in response to Witness Revere's statements I will attempt to provide additional clarity on this issue by adding a numerical example as shown on Exhibit A-21.

PA341 section 6w (4) provides for a true-up mechanism. One of the components associated with this true-up as supported by the Company is to reconcile the difference between forecasted capacity costs associated with purchase power compared to the actual amount of capacity costs associated with purchased power as approved by the Commission pursuant to the Company's PSCR reconciliation case for the same period. This variance would become part of a true-up filing as contemplated in PA341, and as discussed further in my direct testimony (page 5, line 11).

Q. In what proceeding are the differences between forecasted capacity costs associated with purchased power, compared to the actual amount of capacity costs associated with purchase power, reviewed today?

A. Those differences are reconciled in the Company's PSCR Reconciliation cases that are filed annually by March 31. That is the current venue in which, among other things, capacity-related costs associated with purchase power are reviewed. Due to the passage of PA 341 section 6w, Commission-approved capacity costs will be

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transferred to the Capacity Charge proceedings. Subsequent Capacity Plan proceedings should then reflect any purchase power capacity cost over/under-recovery.

Q. Are you proposing a change in this current practice of reconciling these costs as part of the PSCR Reconciliation cases filed each March 31?

A. No.

Q. How does the Company propose changing the way it flows through the over or under-recovery between the capacity related costs associated with purchase power that are estimated, and actual costs to its customers?

A. I gave a narrative example of how Commission-approved capacity costs would be removed from the PSCR to the Capacity Plan and True-up proceedings in my direct testimony and as shown on Exhibit A-16. Beginning in June 2018, DTE Electric proposes that any differences in capacity related purchase power costs (forecasted vs. actual) ordered as part of the PSCR Reconciliation cases become part of the capacity true-up filing identified in PA341 section 6(w) 4 for rate recovery purposes.

Q. Can you please provide an example of the Company's proposal?

A. Yes. As reflected on Exhibit A-21, page 1 of 1, is an example of how the costs related to purchase power capacity would be reconciled and recovered through the Company's PSCR Reconciliation filings and separate capacity filings, respectively. Line 4 reflects a projected annual purchase power capacity cost of $174 million associated with purchase power in 2018, which is added to the fixed capacity costs of $1,600 million, for a total of $1,774 million. For the purposes of this example, the capacity charge is in effect for only seven months of 2018. Now let's assume that in the 2018 PSCR Reconciliation filing, filed on March 31, 2019, as shown on lines 9 through 14, the Company reflects, and subsequently gets approved, that actual annual capacity costs associated with purchase power for 2018 is $154 million, or a $20 million variance. Since this capacity charge was only effective for seven months of 2018, lines 11 and 12 show 7/12 of these amounts. In the subsequent year capacity charge case following the PSCR Reconciliation Order, DTE Electric would then reflect a $12 million credit to capacity costs (see line 23) in determining the capacity charge rates. I believe treating the reconciliation in this manner is consistent with PA341 section 6 (3) (a) which states that the capacity charge shall include generation costs included in a utility's base rates, surcharges and power supply cost recovery factors, regardless of ownership or purchase.

Q. Staff Witness Revere discusses reconciling the differences in revenues received for capacity-related purchase power compared to actual costs (page 14, lines 9 through 18). Do you agree?

A. No. PA341 section 6 (w) 4, makes no mention of reconciling power supply-related revenues collected from customers compared to actual costs.

Q. Does this conclude your rebuttal 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.	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

KELLY A. HOLMES

DTE ELECTRIC COMPANY
QUALIFICATIONS OF KELLY A. HOLMES

Line No.

Q. What is your name, business address and by whom are you employed?

A. My name is Kelly A. Holmes. My business address is One Energy Plaza, Detroit, MI 48226-1221. I am employed by DTE Energy Corporate Services LLC within Regulatory Affairs as Principal Financial Analyst – Regulatory Economics.

Q. Who are you testifying on behalf of?

A. I am testifying on behalf of DTE Electric Company (DTE Electric or Company).

Q. What is your educational background and business experience?

A. I received a Bachelor of Business Administration with an emphasis on accounting from the University of Michigan Business School in 1997. From 1997 until 2001, I was employed by Plante Moran LLP as a financial auditor. While employed at Plante Moran, I passed the Certified Public Accountant (C.P.A) examination in 1997 and became a licensed C.P.A in 1999 upon satisfying the work experience requirement. I had several positions of increasing responsibility, ultimately serving as the Senior Auditor on client engagements. In this role, I was responsible for tailoring each audit based on a client's industry and the risks inherent in their operations, supervising the audit fieldwork, and communicating the audit issues and results with client management.

In 2001, I joined Kmart Corporation as a Senior Operations Auditor. My responsibilities included planning and performing operational audits within various departments of Kmart, and making recommendations to improve Kmart's efficiency and reduce costs.

In 2002, I joined DTE Electric as a Financial Accountant within the Controller's Organization. My responsibilities included accounting, budgeting and reporting for electric revenues as part of the Gross Margin Analysis group. In 2003, I was promoted to Senior Financial Analyst within Gross Margin, and my responsibilities expanded to include detailed financial modeling of the electric revenue to analyze the impact of regulatory and pricing changes, as well as forecasting related to DTE Electric's Power Supply Cost Recovery Clause. I was also involved in preparing supporting schedules and exhibits for Case No. U-14838 and Case No. U-15244. In December 2008, I accepted my current position as a Principal Financial Analyst in Regulatory Affairs Pricing and Rate Design. My current responsibilities include the development of customer rates and the development, application and administration of the Company's tariffs, rules and regulations.

Q. Have you testified previously before the Michigan Public Service Commission ?

A. I have sponsored testimony in the following cases:

U-15806-EO	2009 Energy Optimization Plan
U-15890-EO-A	Amended Energy Optimization Plan
U-15677-R	2009 PSCR Reconciliation
U-16047-R	2010 PSCR Reconciliation
U-16246	2009 Restoration Expense Tracking Mechanism
U-16263	RARS Reconciliation
U-16358	2009 EO Reconciliation
U-16472	DECo General Rate Case
U-16578	2010 Restoration Expense Tracking Mechanism
U-16671	2011 Amended Energy Optimization Plan

U-16780	Revenue Decoupling Mechanism Reconciliation
U-16813	Choice Implementation Surcharge Reconciliation
U-16434-R	2011 PSCR Reconciliation
U-16956	2011 Restoration Expense Tracking Mechanism
U-17049	Amended Energy Optimization Plan
U-17146	Low Income and Energy Efficiency Fund/Vulnerable Household Warmth Fund Reconciliation
U-16892-R	2012 PSCR Reconciliation
U-17097-R	2013 PSCR Reconciliation
U-17319-R	2014 PSCR Reconciliation
U-17680-R	2015 PSCR Reconciliation
U-17689	DTE Electric Public Act 169 of 2014 Filing
U-17762	2016 Energy Optimization Plan
U-17767	DTE Electric General Rate Case
U-17920-R	2016 PSCR Reconciliation
U-18014	DTE Electric General Rate Case

DTE ELECTRIC COMPANY
DIRECT TESTIMONY OF KELLY A. HOLMES

Line
No.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to support the proposed capacity charge rate design and related tariff modifications for the Company's commercial secondary and lighting rate schedules pursuant to the requirements of 2016 PA 341, including a request for a temporary waiver related to the availability of service on the Company's commercial interrupbtible service rate.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring, in part, the following exhibits:

Exhibit	Schedule	Description
A-11	2	Present (U-18014) and Proposed Rate Designs by Rate Schedule
A-12	1	Proposed Tariff Sheets

With respect to Exhibit A-11, Schedule 2, I am sponsoring the pages for the commercial secondary tariff offerings on pages 11 through 23, and the outdoor protective and municipal lighting tariffs on pages 39 through 49. Company Witnesses Mr. Bloch and Mr. Williams are sponsoring the remaining customer classes in this exhibit. On Exhibit A-12, Schedule 1, I am sponsoring the proposed changes to the tariff pages for the commercial secondary and lighting classes. Witnesses Bloch and Williams are sponsoring the remaining sheets contained in this exhibit.

Q. Were these exhibits prepared by you or under your direction?

A. Yes, they were.

Line
No.

Q. What is the basis for the Company's proposed commercial secondary and municipal rates in this proceeding?

A. For both the commercial secondary and municipal classes, the basis for the proposed power supply rates is the functionalized power supply cost of service study supported by Company Witness Mr. Lacey in his Exhibit A-14. Witness Lacey's Exhibit A-14 contains the power supply revenue requirement for each rate class (line 1), and how much of each revenue requirement relates to capacity (line 6) and non-capacity (lines 2 through 5).

Q. How will the revenue requirements provided by Witness Lacey be further allocated to the individual rate schedules to allow for rate design?

A. Within the power supply cost of service for the commercial secondary class, Witness Lacey identifies three separate commercial secondary cost classes: 1) D3/Other, 2) D3.2 and 3) D4. For the D3/Other rate schedules the power supply revenue requirements (both capacity and non-capacity) were allocated based on each rate schedule's percentage contribution to the present D-3/Other power supply revenue. This is the same method of allocation used by both the Company and MPSC Staff in developing the approved D3/Other power supply rates in the Company's most recent rate case, Case No. U-18014. The revenue requirements for D3.2 and D4 were directly assigned, since they are individual cost of service classes.

Capacity and non-capacity power supply rates were designed for each commercial secondary rate schedule. To design the non-capacity rates, the non-capacity revenue requirement allocated to each rate schedule as described above was divided by the respective rate schedule's total power supply sales volume to develop an energy based non-capacity charge (exceptions for the D4 class and D3.1 class as noted below). The capacity charge(s) for each commercial secondary rate schedule were then calculated as the difference between the existing power supply rates and the non-capacity rate. For the D4 class, which has a power supply demand charge, I have included the associated revenue as capacity, so the capacity enegy rates were designed to recover the remaining capacity revenue requirement. Under existing rates established in U-18014, the D3.1 unmetered General Service class is billed one energy charge that covers both power supply and distribution costs. To ensure that only the capcity revenue is collected through the capacity charge, I designed the capacity energy rate component by dividing the sales by the allocated capacity revenue requirement, and the non-capacity charge was then set equal to the existing energy charge less the calculated capacity charge, thus recovering the same total amount through energy charges as in Case U-18014.

As supported and instructed by Company Witness Mr. Stanczak, Exhibit A-11 reflects that bundled customers will be charged both the non-capacity and capacity power supply charges, while only the power supply capacity charges may be applicable to Electric Choice customers. As also supported and instructed by Witness Stanczak, in this case the Company is assuming that no Electric Choice customers will take capacity service from the Company. The capacity and non-capacity charges proposed in this case are designed such that the sum of these two pieces is equivalent to the existing bundled service power supply rates. To illustrate this, the below table shows how the total Rate Schedule D3 power supply rate for a bundled customer is the same under existing rates and the proposed structure. The

Line No.

Company is not proposing any changes to its existing commercial secondary distribution rates.

Rate Schedule D3 Total Power Supply Rates: Current Versus Proposed (cents)

Line No	Charge	Current	Proposed
1	Non-Capacity Charge	N/A	3.266
2			
3	Capacity Charge	N/A	4.478
4			
5	Total Power Supply Rate:	7.743	7.743
6	Total Power Supply Revenue ($000)	$550,624	$550,624

Q. How were the revenue requirements provided by Witness Lacey used in the lighting rate design?

A. Within the lighting tariffs, Witness Lacey identifies four separate cost of service groups: 1) D9 Outdoor Protective Lighting (OPL), 2) D9 Commercial OPL, 3) E1 Street Lighting, and 4) E2 Traffic Signals. For purposes of rate design, I have combined the two OPL cost classes, as they are served under the same tariff and have equivalent service offerings and prices. This is also consistent with Case U-18014.

The rate design process for the lighting classes is much the same as for the commercial secondary class. However, due to the manner in which lighting revenues were split between power supply and distribution in Case No. U-18014, the capacity revenue ties directly to the Witness Lacey's revenue requirement but the resulting non-capacity revenue does not. Prior to the approval of the current rate structure in Case No. U-18014 for the lighting rate schedules (consisting of a monthly fixture charge and volumetric energy charge), lighting customers were billed a flat per lamp charge which was designed to recover both the power supply and distribution revenue. Due to this, in preceding cases (including U-18014), the power supply and distribution revenue classifications for each lighting rate schedule have been based on a percentage of the total revenue for that schedule, rather than the actual power supply and distribution revenue requirement. Since this case is intended to be revenue neutral, I have designed the capacity and non-capacity rates to keep the power supply and distribution revenue totals equal to those approved in Case No. U-18014. To ensure that the rates reflect full recovery of the capacity revenue, I designed the capacity energy rate component by dividing the sales for each rate schedule by the capacity revenue requirement as provided by Witness Lacey. The non-capacity charge was then set equal to the existing energy charge less the calculated capacity charge, thus recovering the same amount through energy charges as in Case U-18014. For the OPL class, this process results in capacity revenue equal to the capacity revenue requirement, non-capacity revenue lower than the non-capacity revenue requirement by approximately $150,000, and total power supply revenue equal to the amount in Case No. U-18014. The difference in non-capacity revenue requirement is recovered as part of distribution rates. For both the E1 and E2 classes, this process results in capacity revenue equal to the capacity revenue requirement, non-capacity revenue in excess of the non-capacity revenue requirement (by approximately $245,000, combined), and total power supply revenue equal to the amount in Case No. U-18014. The difference in non-capacity revenue requirement is recovered as part of distribution rates. The net impact of this process on the lighting group as a whole is de minimis, and in future filings the proposed rates will be developed so that the proposed revenue components and revenue requirements do agree.

Q. What tariff rate changes are you proposing in this case?

A. On Exhibit A-11, Schedule 2, I show the rates approved by the Michigan Public Service Commission (MPSC) in Case No. U-18014 through the Order issued January 31, 2017 and the erratum issued February 10, 2017, and the rates being proposed in this case to establish capacity charges. For all of the rate schedules I am sponsoring, the various billing components are listed in column (a), and the respective billing determinants, including units of measure, are listed in column (b). The billing determinants are the same billing determinants which were used to develop the Company's approved rates in the Commission's January 31, 2017 Order in Case No. U-18014, the Company's last approved rate case. For the commercial secondary rate schedules on pages 11 through 23 and the traffic light rate schedule on page 49 of Exhibit A-11, Schedule 2, the Company's existing rates, as approved in Case No. U-18014, are in column (c), and are used to calculate the present revenues in column (d). The rates proposed in this proceeding are in column (e), with the resulting revenues in column (f). As can be seen from comparing the present revenues in columns (d) and the proposed revenues in column (f), the rates proposed in this case are designed to be revenue neutral, and recover the same total revenue approved in Case No. U-18014.

For the remaining lighting rate schedules I sponsor on pages 39 through 48 of the exhibit, the existing luminaire and energy rates as approved in Case No. U-18014 are listed in columns (c) and (d), respectively, and the total present revenue including both of these components is in column (e). The rates proposed is this proceeding consist of the luminaire charge in column (f) which will remain the same, the non-capacity energy charge in column (g), and the capacity charge in column (h). The total resulting revenue, which is revenue neutral with the amount approved in U-18014, is shown in column (i).

Q. Can you describe how the new rates will appear in the tariffs?

A. Yes. Exhibit A-12, Schedule 1 contains the proposed tariff sheet changes necessary to incorporate the capacity charges being proposed for each rate schedule.

Q. Are you requesting any other changes related the tariffs, which are not reflected on Exhibit A-12, Schedule 1?

A. Yes. There is an availability of service restriction on the Company's commercial Interruptible Service Rate, D3.3, which limits this rate to serving no more than 300 customers. As explained by Witness Stanczak in his testimony, in the event that a significant amount of Electric Choice load returns to DTE Electric service and the Company is unable to procure the required capacity in the short-term, the Company is proposing to charge a reduced interruptible capacity charge for the Electric Choice load that is not supported by either Company owned or purchased capacity. Therefore, I am requesting a temporary waiver of the 300 customer restriction (if needed) so that this rate option would be available to customers until the firm capacity needs are met.

Q. Does this complete 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 341 for	)	Case No. U-18248
DTE ELECTRIC COMPANY'S	)	
service territory.	)	

REBUTTAL TESTIMONY

OF

KELLY A. HOLMES

DTE ELECTRIC COMPANY
DIRECT TESTIMONY OF KELLY A. HOLMES

Line
No.

Q. What is your name, business address and by whom are you employed?

A. My name is Kelly A. Holmes. My business address is One Energy Plaza, Detroit, MI 48226-1221. I am employed by DTE Energy Corporate Services LLC within Regulatory Affairs as Principal Financial Analyst – Regulatory Economics.

Q. Did you file direct testimony in this proceeding on behalf of DTE Electric Company (DTE Electric or Company)?

A. Yes, I did.

Q. Are you sponsoring any exhibits along with your rebuttal testimony?

A. No, I am not.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to rebut the Michigan Public Service Commission Staff (Staff) proposed commercial rate design.

Q. On Page 12 of Staff Witness Mr. Revere's direct testimony, he states, "Staff recommends that capacity-related costs be collected through summer on-peak kWh charges for rate schedules without demand charges, and through summer on-peak kW charges for rate schedules with demand charges." How do you respond?

A. Staff's proposed commercial rate design would fundamentally change the way the vast majority of commercial customers are charged for electric service, as it would create mandatory time of day rates for all commercial customers going forward. Under Staff's proposal, commercial customers would be subject to rates where

Line
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summer on peak energy consumption would be charged a premium which I believe is beyond the scope of this proceeding.

This rate design should not be implemented in this case, for the following reasons:

- Staff provides no analysis or testimony on the financial impact its commercial rate design proposal would have on DTE Electric's customers (positive or negative).
- For rate design purposes, Staff assumes the portion of commercial usage that will be summer on peak usage will be equal to the historic average annual percentage of on peak usage for 2014-2016, thereby providing no analysis or testimony on how its proposal will impact the amount of energy customers will use during the summer on peak period, or what affect any such change will have on the Company's revenue recovery, all of which should be carefully analyzed and considered before adopting such a proposal. Staff also did not propose any capacity charge for Rate Schedules D1.1 and D5.
- Capacity cost recovery through power supply rates is being proposed to be broken out into separate capacity rates in this case for the first time, due to PA 341. However, capacity costs were not created by PA 341; they have historically been, and are currently, recovered through power supply rates. While the Company is simply proposing to "unbundle" the existing power supply rates into capacity and non-capacity, Staff's proposal would fundamentally change how the capacity costs are recovered from customers.
- Commercial customers have not historically elected to participate in the Company's time of day price offerings. Rate Schedule D1.8, Dynamic Peak Pricing, has minimal participation as the hours are not advantageous or in most

Line No.

respects coincide with commercial operations. The Company's previous commercial time of day offering, Rate Schedule D3.4 Optional Time of Day General Service Rate, was eliminated in Case No. U-16472 for these reasons. There were only 14 participating customers at the time. Customers may not truly understand the nature of a capacity charge administered based on summer on-peak hours, as they may perceive it as time of day charge they cannot avoid through modifications to their operations.

- Staff provides no analysis or testimony on the affect its commercial rate proposal would have on customer satisfaction which in DTE Electric's opinion would diminish.

The Company does not believe this case should fundamentally change how commercial customers are charged for electric service, and thus Staff's rate design proposal should be denied for that reason alone, in addition to the issues discussed above. The Company's proposed commercial capacity and non-capacity rate design, whereby each rate schedule's basic structure is maintained, should be approved. Unlike the Company's rate design proposal, Staff's proposal would have significant impact on rate structure and the individual bills of commerial customers. If the Staff feels such a fundamental change should be considered, it should be addressed in a general rate case and include the appropriate supporting studies which identify how these changes impact customer usage and behavior and not take place as part of this proceeding.

Q. Does this complete your rebuttal testimony?

A. Yes, it does.

STATE OF MICHIGAN

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QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

THOMAS W. LACEY

DTE ELECTRIC COMPANY
QUALIFICATIONS OF THOMAS W. LACEY

Line
No.

Q. What is your name, business address and by whom are you employed?

A. My name is Thomas W. Lacey. My business address is One Energy Plaza, Detroit, Michigan, 48226. I am employed by DTE Energy Corporate Services, LLC (DTE Energy or DTE) as a Principal Financial Analyst in the Revenue Requirements Department of the Regulatory Affairs Organization.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of DTE Electric Company (DTE Electric or the Company).

Q. What is your educational background and business experience?

A. I received a Bachelor of Science Degree in Accounting from Michigan State University in 1981 and a Masters in Business Administration from Wayne State University in 1992. From 1982 until 2001, I was employed by ANR Pipeline Company (ANR) in the Rates and Regulatory Affairs department. I had several positions of increasing responsibilities within the Rates area, ultimately rising to the position of Senior Rates Analyst. During my nineteen years with ANR, I worked on numerous rate proceedings and filings before the Federal Energy Regulatory Commission (FERC) including rate cases (FERC Docket Nos. RP82-80, RP83-79, RP86-169, RP89-161, RS92-1 and RP94-43). My work was primarily in the areas of cost-of-service and rate design. In 2002, I joined DTE as a Financial Analyst in the Load Research department of Regulatory Affairs. I worked in Load Research until December 2005. My responsibilities within Load Research included extensive work on the 2003 Michigan Consolidated Gas Company (MichCon) rate case (U-13898) and The Detroit Edison Company (Detroit Edison) rate filings. In December 2005, I accepted my current position.

Q. What are your responsibilities as a Principal Financial Analyst for both DTE Electric and DTE Gas?

A. As a Principal Financial Analyst, my responsibilities include the preparation of revenue requirements, cost of service and rate design, testimony, exhibits and workpapers, in cases for both DTE Gas and DTE Electric. I am also responsible for managing certain MPSC filings such as DTE Electric's Renewable Energy Plan (REP) Plan case: U-17793 and DTE Electric's most recent depreciation case U-18150.

Q. Have you previously sponsored testimony in cases before the Michigan Public Service Commission (MPSC or Commission)?

A. Yes, I have. I have sponsored testimony in the following cases:

U-13898	MichCon's 2006 Uncollectible Expense True-up Mechanism and Safety and Training Related Expenditure Report
U-15985	MichCon's 2009 General Rate Case Proceeding
U-16290	Reconciliation of MichCon's 2010 Energy Optimization (EO) Program
U-16730	MichCon's 2011 Updated Energy Optimization Plan
U-16730	MichCon 2011 Updated Energy Optimization Plan
U-16751	Reconciliation of the MichCon 2011 EO Program
U-16999	MichCon 2011 General Rate Case Proceeding
U-17288	Reconciliation of the DTE Gas 2012 EO Program
U-17602	Reconciliation of the DTE Electric 2013 EO Program
U-17608	Reconciliation of the DTE Gas 2013 EO Program
U-17632	Reconciliation of the DTE Electric 2013 REP Program

U-17762	DTE Electric 2016/2017 Energy Optimization Plan
U-17763	DTE Gas 2016/2017 Energy Optimization Plan
U-17804	Reconciliation of the DTE Electric 2014 REP Program
U-17832	Reconciliation of the DTE Electric 2014 EO Program
U-17841	Reconciliation of the DTE Gas 2014 EO Program
U-18014	DTE Electric General Rate Case Proceeding
U-18111	DTE Electric Amended REP Plan

Q. Have you previously testified or submitted testimony in any other regulatory proceedings?

A. Yes. I sponsored testimony in ANR's general rate case in Docket No. RP94-43. I testified at a hearing before the FERC in Docket No. RP94-43.

DTE ELECTRIC COMPANY
DIRECT TESTIMONY OF THOMAS W. LACEY

Line
No.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present the proposed revenue requirement to be recovered in the capacity charge calculated by Company Witnesses Mr. Bloch, Ms. Holmes, and Mr. Williams.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

Exhibit	Schedule	Description
A-13	1	U-18014 Order Cost of Service Study
A-13	2	U-18014 Power Supply Expenses
A-14		Capacity Charge Revenue Requirement
A-15		Variable O&M

Q. Were these exhibits prepared by you or under your supervision?

A. Yes, they were.

Q. Are you providing the Case No. U-18014 approved COSS details in this case?

A. Yes. Exhibit A-13, Schedule 1 contains the cost of service study (COSS) for production costs approved in the Commission's January 31, 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 cost of service study (COSS) approved in the Commission's January 31, 2017 order in Case No. U-18014.

Q. What costs have you included in your calculation of capacity revenue requirement?

A. On Exhibit A-14 as directed by Company Witness Mr. Stanczak, I have included all costs included in the Commission's January 31, 2017 order in Case No. U-18014 COSS identified as Production, except fuel, variable Operation and Maintenance Expenses (O&M) and certain purchase power costs explained later in my testimony.

Q. What is the calculation of capacity revenue requirement based upon?

A. The calculation of capacity revenue requirement on Exhibit A-14 is based upon costs and allocations approved in the Commission's January 31, 2017 order in case No. U-18014. The cost of service study approved in the Commission's January 31, 2017 order in Case No. U-18014, as prepared by the Commission Staff is the starting point for all my calculations. Exhibit A-13, Schedule 1 reflects the Production Cost portion of that study.

Q. What costs are reflected on Exhibit A-14?

A. Line 1 of Exhibit A-14 exactly matches line 27 from the COSS for Production costs approved in the Commission's January 31, 2017 order in Case No. U-18014, as prepared by the Commission Staff, and reflected on Exhibit A-13 Schedule 1. Line 2 is a reduction in revenue requirement for projected energy sales revenue net of projected fuel costs, calculated by Company Witness Ms. Wojtowicz on Exhibit A-10. Line 3 is a reduction to the revenue requirement for fuel included in the Order COSS. Line 4 is a reduction to the revenue requirement for Non-capacity related purchased power. Line 5 is a reduction to the revenue requirement for variable O&M.

Line No.

Line 6 is the total capacity cost revenue requirement that I supply to Witnesses Bloch, Holmes, and Williams.

Q. Did you reduce the capacity charge revenue requirement for any non- capacity related purchased power for rate classes D11 and Rider 10?

A. Yes. On line 4 of Exhibit A-14, I reduced the capacity charge revenue requirement for non-capacity related purchased power for rate classes D11 and Rider 10. The reason for this adjustment is these costs are not capacity-related, these purchase power costs are for energy charges purchased from MISO for Rider 3 and Rider 10. For this reason, the $194.0 million purchased power expense identified on line 5 of Exhibit A-13, Schedule 1 in the Order COSS is considered to be all capacity except for the $50.3 million directly assigned to Rider 10 and $0.2 million assigned to Rider 3 (which is included with D11). The $50.3 million of non-capacity cost is equal to the sum of the R10 MISO pricing Option costs listed on line 20 of Exhibit A-13, Schedule 2 and Voltage Level adder costs listed on line 21 of Exhibit A-13, Schedule 2.

Q. Did you make any other adjustments?

A. I also adjusted for variable O&M on line 5 of Exhibit A-14.

Q. What costs did you include on line 5 of Exhibit A-14 for variable O&M?

A. On Line 5 of Exhibit A-14 I reflected variable O&M which is calculated on Exhibit A-15. I only included the non-labor portions of Accounts 501 (Fuel Handling), 502 (Steam Expenses), 505 (Electric Operation Expenses), 519 (Coolants and Water), 520 (Steam Expenses), 538 (Electric Maintenance Expenses) and 548 (Peaker

Expenses).

Q. Why did you only include the non-labor portion in variable O&M?

A. The National Association of Regulatory Utility Commissioners (NARUC) Electric Utility Cost Allocation Manual (Manual) describes the classification of production plant in Chapter 4 of the manual. Chapter 4 describes that accounts 502, 505, 519 and 538 should be: Classified between demand and energy on the basis of labor expenses and materials expenses. Labor expenses are considered demand-related, while material expenses are considered energy-related. Therefore, I determined only the material related costs are variable, and that account 501 and 548 should be handled in the same manner. In Chapter 4, the Manual states:

> Production plant costs are either fixed or variable. Fixed production costs are those revenue requirements associated with generating plant owned by the utility, including cost of capital, depreciation, taxes and fixed O&M. Variable costs are fuel costs, purchased power costs and some O&M expenses. Fixed production costs vary with capacity additions, not with energy produced from given plant capacity, and are classified as demand-related. Variable production costs change with the amount of energy produced, delivered or purchased and are classified as energy-related.

Q. Why did you only include the above accounts in variable O&M?

A. Based on my review of the descriptions of the various production O&M accounts in the Code of Federal Regulations (CFR) only these accounts appear to be variable. The descriptions for these accounts includes variable material costs such as lubricants, chemicals and water.

Q. Does this conclude your direct testimony?

A. Yes, it does.

STATE OF MICHIGAN

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REBUTTAL TESTIMONY

OF

THOMAS W. LACEY

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF THOMAS W. LACEY

Q. What is your name, business address and by whom are you employed?

A. My name is Thomas W. Lacey. My business address is One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Energy Corporate Services, LLC, a subsidiary of DTE Energy Company (DTE Energy) as a Principal Financial Analyst in the Revenue Requirements Department of the Regulatory Affairs Organization.

Q. Did you file direct testimony in this proceeding on behalf of DTE Electric Company (DTE Electric or Company)?

A. Yes, I did.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to address the direct testimonies of Michigan Public Service Commission Staff (Staff) Witness Mr. Revere, Association of Businesses Advocating Tariff Equity (ABATE) Witness Mr. Dauphinais, and Constellation New Energy, Inc. (CNE) Witness Mr. Makholm relative to their respective proposals for determining DTE Electric's level of capacity costs.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits.

Exhibit	Description
A-18	NARUC Electric Utility Cost Allocation Manual
A-19	Reconciliation of Company Position vs. Staff Witness Revere
A-20	Summary of Adjustments to Capacity Revenue Requirement

Q. Were these exhibits prepared by you or under your direction?

A. Yes, they were.

Q. Did you discover any mistakes in the respective direct testimonies of Staff Witness Mr. Revere, ABATE Witness Mr. Dauphinais, and CNE Witness Mr. Makholm?

A. Yes. Staff, ABATE and CNE, in their respective direct testimonies, advocate classifying costs using allocation methodologies. This is inappropriate because classification and allocation have two entirely different purposes in a cost of service study used to establish utility rates. Specifically, Staff (Revere direct, page 7) and ABATE (Dauphinais direct, page 20) propose using the 75% weighting component of the 4CP 75-0-25 allocator (multiple coincident peaks) and CNE proposes to use of the Average and Excess method (Makholm direct, pages 23-27). The allocation of costs to the appropriate class of customers, is for collecting these costs. The classification of costs, on the other hand, is the identification of the type of cost (Demand, Energy, or Customer). For Production-related costs, the National Association of Regulatory Utility Commissioners' (NARUC) Cost Allocation manual (See Exhibit A-18, pages 35-38), identifies only two categories: Demand or Energy.

Q. Why do you claim that the 4CP75-0-25 and Average and Excess method are allocation and not classification methods?

A. The NARUC manual describes each method and includes examples (pages 41-52). The descriptions clearly reflect these methods are for the allocation of production costs, and each of the included examples (see Tables 4-1, 4-2, 4-3, 4-4, 4-5, 4-6, 4-7, 4-8, 4-9 and 4-10A-C) clearly show the split of costs to customer groups only. The classification of costs, into types of costs, is separately described on pages 35-38 of the NARUC manual and involves an account by account analysis, which Staff, ABATE and CNE did not describe in their direct testimonies.

Q. Does CNE understand the difference between allocation and classification?

A. It appears not. In describing their proposal, to use the "Average and Excess" method CNE states "The method is familiar and widely discussed as one of the principal methods of using embedded costs to allocate production costs for electric utilities" (Makholm direct, pages 24-25). The fact a method is widely used to **allocate** costs is not relevant to the **classification** of costs.

Q. What else does Mr. Makholm say on allocation and classification?

A. Mr. Makholm partially quotes the NARUC manual, as follows:

> Mr. Lacey uses a peak demand method, which the NARUC manual describes as comprising the following features: "… all production plant costs are classified as demand related …these costs are allocated among the rate classes on factors that measure the class contribution to the system peak." (Makholm, direct, pages 23-24)

The partial quote, clarifies the issue when viewed in its entirety. The full quote is as follows (omitted words in bold):

> **First,** all production plant costs are classified as demand related. **Second,** these costs are allocated among the rate classes on factors that measure the class contribution to the system peak." (NARUC manual, page 24)

When read in in its full context, it is clear the NARUC manual considers classification as the first and separate step, followed by the allocation to customer classes.

Q. Does ABATE understand the distinction between allocation and classification?

A. It is unclear. ABATE correctly describes that "DTE completed its new classification between capacity-related and non-capacity related costs" (Dauphinais direct, page 15). However, Mr. Dauphinais later claims DTE Electric "inappropriately classifies the 25% energy usage allocation of fixed production costs to capacity-related costs" (Dauphinais direct, page 16). Costs should not be classified using an allocation method of any kind, including the 25% energy allocation weighting. The 75-25 weighting was purely an allocation method approved in U-18014. To put this in perspective, if in Case No. U-18014, the Commission had approved 4CP100-0-0, my calculation of capacity-related costs in this case would have been the same. It appears Mr. Dauphinais believes that if 100-0-0 had been approved then all production costs should be classified as capacity related. This is simply incorrect.

Q. What is your basis for rejecting the use of the 75-25 allocation method to classify costs?

A. The embedded costs in DTE Electric's Production revenue requirement are either demand or energy related. Demand related costs are fixed costs that are incurred regardless of the level of energy use and are related to the plant or unit's capacity to produce energy. The method used to allocate these fixed costs does not change their nature (i.e. they remain fixed costs that are incurred regardless of the level of energy use).

An examination of the Company's recent experience with allocation methodologies in general rate cases demonstrates the potential volatility an approach that relies on an allocation methodology to classify costs can cause. In Case No. U-17767, production costs were allocated using 50-25-25 where only 50% of applicable production costs were allocated based on demand; in Case No. U-18014, DTE Electric proposed 100-0-0 which would result in 100% of applicable production costs being allocated on demand. If the classification proposals advocated by Staff and ABATE were inappropriately adopted by the Commission in the instant case, the capacity related costs could swing between 50% and 100% capacity based on whatever allocation is method approved in future general rate cases. The allocation methodology should not be used to classify cost.

Q. Are there any instances in other MPSC cases where Staff did not support the reduction of capacity related costs by the energy component of the 72/25 allocation method?

A. Yes. As more fully described in the rebuttal testimony of Company Witness Mr. Stanczak, in MPSC Case No. U-17032 Energy Michigan proposed to reduce a capacity charge by 25%, citing the 25% energy component of the 75/25 allocation method used to allocate certain production fixed costs. Staff opposed Energy Michigan's proposal, correctly asserting that "If the capacity rate is reduced by 25% as recommended by Energy Michigan, Open Access Distribution (OAD) customers will only be paying for 75% of capacity costs, while standard service customers will pay 100%, which would be inconsistent with Michigan's ratemaking principles." (MPSC Case U-17032, Order dated September 25, 2012)

Q. What costs has Staff identified as capacity-related costs?

A. Staff Witness Nicholas Revere at page 6 of his testimony, appears to create three types of production costs: 1) energy-related, 2) capacity-related demand and 3) non-capacity-related demand. Witness Revere states the following at page 7 of his direct testimony:

> "Staff identified costs currently allocated using the production cost allocator and other capacity-related costs. The current production cost allocator of 4CP (four-coincident peak) 75-25 effectively recognizes that 75% of costs so allocated are capacity-related. Therefore, Staff split the costs into capacity- and non-capacity-related portions, using the 75-25 split.

Q. Do you agree the methodology Staff used to calculate capacity-related costs?

A. No. As stated above, the Commission should reject Staff's method and approve the methodology used to produce Exhibit A-14. Also, there are not three types of production costs. As explained above, the NARUC manual only identifies two types: demand and energy. In addition to being an inappropriate methodology to determine the type of cost, I found an additional flaw within Staff's methodology. Specifically, the costs Staff decided to include in the capacity costs were included inconsistently or incorrectly.

Q. What did Staff offer in support of its determination of production capacity costs from the Cost of Service Study?

A. Witness Revere states: "Staff went through the Cost of Service Study (COSS) and identified those (costs) that are capacity-related" (Revere direct, page 7). The result of that effort is displayed as a single amount of $714,485 thousand, labeled "COSS Capacity Revenue Requirement" on Exhibit S1.1 and listing WP-NMR-1 * .75 as the source.

Q. Have you examined WP-NMR-1?

A. Yes. To understand which costs Staff chose to classify as capacity-related, I

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examined WP-NMR-1 which is the Production portion of the Staff's Order Cost of Service from MPSC Case No U-18014.

Q. How does Staff's determination of the production capacity related costs compare to the Company's?

A. As shown on Exhibit A-19, line 35, Staff's capacity amount is more than $1,011 million less than the Company's amount, and represents a reduction of more than 58%.

Q. What costs did Staff omit to produce such a large reduction?

A. Staff omitted certain fixed capacity costs that are incurred by DTE Electric regardless of the level of energy produced. Specifically, Staff improperly and without adequate supporting testimony omitted (See Exhibit A-19, column (c)):

- over $884 million from rate base;
- almost $520 million from operation and maintenance (O&M) expense;
- over $28 million from Taxes Other Than Income;
- almost $10 million in depreciation related expense;
- $160 million in income taxes

Further, Staff improperly handled the Allowance for Funds Used During Construction (AFUDC) by reflecting this income statement item as a component of rate base. Staff failed to account for the revenue requirement effect of the production revenue deficiency associated with the rate increase from Case No. U-18014. Another contributor to the difference in the amount supported Staff vs. the Company is that Staff included the portion of Power Purchases that are allocated based on demand.

Q. Based on your review of Staff's determination of production capacity costs, do you agree any adjustments are necessary to the amount in your direct testimony?

A. Yes. I do agree with some of Staff's adjustments and will identify those below.

Q. What comprises the amounts that Staff omitted from rate base?

A. As shown on Exhibit A-20, line 4, Staff omitted $711.1 million of working capital. Staff also omitted $168.0 million of capitalized nuclear fuel, $37.4 million of capital costs associated with the Midwest Energy Resources Company (MERC), and improperly credited $31.4 million of the income adjustment for AFUDC to rate base.

Q. Is working capital a cost that should be included in DTE Electric's production capacity costs?

A. Yes. Working capital is the money provided by investors and used to pay salaries, materials and supplies and other current expenses which must be paid by the utility until reimbursement is obtained from ratepayers. The MPSC requires the use of the balance sheet method of determining working capital which generally defines working capital as current assets less current liabilities. Working capital is needed for the continued operation of the DTE Electric's generating capacity and is properly included in the basis for the production capacity charge.

Q. Is capitalized nuclear fuel a cost that should be included in DTE Electric's production capacity costs?

A. Nuclear fuel inventory is properly included in rate base but could reasonably be omitted from the basis for the production capacity charge as Staff suggests because the inventory may vary with the level of energy produced, depending on one's time horizon. In the restatement of Staff's basis for the production capacity basis, which appears on Exhibit A-20, I have not included the capitalized nuclear fuel.

Q. Are the costs associated with MERC appropriate for inclusion in the Company's fixed production capacity costs?

A. MERC is the Company's fuel handling facility located in Superior, Wisconsin. The Commission has approved the inclusion of its capital costs in rate base. These capital costs are offset in the Company's PSCR reconciliation proceedings by a credit for the revenue the Company realizes from providing fuel transportation services to third parties. Since Choice customers are not subject to PSCR surcharges and therefore do not receive the benefit of the revenue credit, it is reasonable to exclude MERC capital costs from the rate base component of the basis for the production capacity charge in this case. In the restatement of Staff's basis for the production capacity charge which appears on Exhibit A-20, I have not included the MERC related capital costs and depreciation amortization expense.

Q. How should AFUDC be handled for purposes of establishing the basis for the production capacity charge?

A. AFUDC is an income statement item used to offset for Construction Work in Process (CWIP) for projects costing in excess of $50 thousand and requiring over six months to build. Since CWIP is included in rate base, it would be appropriate to decrease the overall production cost basis by the AFUDC amount as is shown in the restatement of Staff's basis for the production capacity basis which appears on Exhibit A-20.

Q. What comprises the amount Staff omitted from O&M?

A. Staff omitted $94.6 million of production operation labor, $256.5 million of non-labor production O&M expense and $168.6 million of production Administrative and General (A&G) expense.

Q. Is non-labor production O&M expense an appropriate component of the basis for a production capacity charge?

A. Yes. Non-labor production O&M expenses are required to operate and maintain the Company's generation fleet. As stated in my pre-filed direct testimony, consistent with the NARUC manual, the only non-labor O&M costs that should be omitted are the amounts for accounts 501, 502, 505, 520, 538 and 548.

Q. Is production operational O&M labor an appropriate component of the production capacity charge?

A. Yes. Staff included the labor portion of all maintenance production O&M, but excluded without explanation some of the corresponding operation O&M (Accounts 500, 506, 517, 523, 524, 549 and 556). For example: Staff included all nuclear related maintenance O&M labor (accounts 528-532) including nuclear maintenance supervision (account 528) but excluded the corresponding nuclear operation expenses including supervision (account 517). This inconsistent treatment is not supported and should be rejected.

Q. Is production A&G expense an appropriate component of the basis for a production capacity charge?

A. Yes. Production A&G includes the costs associated with the departments within the

Company that support the operation of the production fleet. Departments include Human Resources, Information Technology, Controller (Accounting), Tax, Legal, and others. Nearly half of the amount in production A&G is for employee pensions and benefits. Staff's inclusion of the labor costs without the associated pension and benefit costs only partially covers the true cost of production capacity. Production A&G should be included in its entirety.

Q. What comprises the amount of production income taxes omitted by Staff?

A. Production income taxes consist of $126.7 million of federal income tax and $33.4 million of Michigan state income tax.

Q. Is production income tax an appropriate component for inclusion in the basis for the production capacity charge?

A. Yes. Staff, without explanation, excluded all income taxes. A utilities' income comes from the return on the equity component of its financial capital structure which is used to finance the capital investment of its production fleet. Staff's inclusion of the production capital investment in rate base without including the associated income taxes only partially covers the cost of production capacity. The Commission should require that production income taxes be included in the basis for the production capacity charge.

Q. What comprises the production taxes other than income amount omitted by Staff?

A. The production taxes other than income amount is comprised of $22.3 million of Social Security tax expense, $5.9 million of MPSC Assessment, and $0.2 million of

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City of Detroit Sale/Use tax.

Q. Are production social security taxes appropriate for inclusion in the basis for the production capacity charge?

A. Yes. Staff's inclusion of production labor O&M without the concomitant production social security taxes, only partially covers the cost of production capacity.

Q. Is the production MPSC Assessment appropriate for inclusion in the basis for the production capacity charge?

A. Yes. The MPSC Assessment is collected from MPSC regulated entities within Michigan and, among other things, is used to fund the salaries and expenses of the MPSC and its Staff. Without this assessment, regulatory proceedings such as the instant case would not be possible. The assessment should be included in the basis for the production capacity charge so that the associated expense is borne equally by both retail electric customers and eligible Choice customers.

Q. What comprises the production depreciation expense omitted by Staff?

A. Production depreciation expense omitted by Staff consists of $6.4 million of amortization for the cost to achieve savings related to the Company's Commission Approved Performance Excellence Program (PEP), $2.4 million for MERC depreciation expense, and $1.0 million for amortization of the Company's DTE-2 Regulatory Asset.

Q. Is the production amortization of the PEP appropriate for inclusion in the basis for the production capacity charge?

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A. The costs to achieve the savings associated with the PEP initiative are valid costs for inclusion in the basis for the production capacity charge. However, in recognition that the amortization period for these costs is nearly complete, the Company is willing to omit them from the basis for the production capacity charge in this case. In the restatement of Staff's basis for the production capacity basis which appears on Exhibit A-20, I have not included the PEP amortization.

Q. Is production MERC depreciation expense an appropriate component for inclusion in the production capacity charge?

A. As explained earlier regarding the capital costs associated with MERC, since Choice customers are not subject to PSCR surcharges and therefore do not receive the benefit of the revenue credit, it is reasonable to exclude MERC depreciation expense from the basis for the production capacity charge.

Q. Is the amortization of the DTE-2 Regulatory Asset appropriate for inclusion in the basis for the production capacity charge?

A. Yes. DTE-2 was the Company's enhancement to the Company's computer based operating systems. Therefore, the amortization of the DTE-2 Regulatory Asset should be included in the basis for the production capacity charge.

Q. Earlier in your rebuttal testimony you stated that Staff failed to account for the revenue requirement effect of the production revenue deficiency associated with the rate increase from Case No. U-18014. Can you explain why?

A. The production revenue deficiency from the Staff's Order conforming cost of service is $83.240 million and that amount is included in the production revenue requirement

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of $3,113.7 million (Exhibit A-19, line 25). The Staff's approach to establishing the basis for the production capacity charge is one I would characterize as a "bottoms up" approach as opposed to the Company's approach which calculates revenue requirement by adding the revenue deficiency to the present revenue. In the bottoms up approach, revenue requirement is calculated by summing the cost components and can be performed without involving revenue. However, as mentioned earlier, taxes are an important component of those costs. Once the Commission-approved production revenue deficiency is included in rates, the Company will be assessed income and other taxes on that amount. Those taxes must be included in the bottoms up revenue requirement calculation. Otherwise, the production capacity cost basis only partially covers the Company's true cost of production capacity.

Q. Have you calculated the tax-related cost associated with the production revenue deficiency?

A. Yes. Per line 22 of Exhibit A-19 the amount is $32.5 million which is the result of multiplying the revenue deficiency of $83.2 million by DTE Electric's composite tax rate of 39%. This is the amount that should be added to the basis for the production capacity charge using the bottoms up approach.

Q. Earlier in your pre-filed rebuttal testimony, you stated that another contributor to the difference in the amount supported by Staff vs. the Company is that Staff included the portion of Power Purchases that are allocated based on demand. How should this Power Purchase expense be treated in developing the basis for the production capacity charge?

A. Inclusion of the portion of Power Purchases that are allocated based on demand is

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only appropriate if you subscribe to the notion that demand related costs can be classified using an allocation methodology, which I do not. The appropriate amount to include for purchased power is the amount supported by Company Witness Ms. Wojtowicz in her pre-filed direct testimony in this case. Therefore, as shown on Exhibit A-19, I have substituted those amounts for the Staff's Purchase Power expense.

Q. Have you made any other adjustments to Staff's basis for the production capacity charge?

A. Yes. To properly align Staff's adjusted bottom up approach with the Company's production revenue requirement, I have made an adjustment to reduce the basis by $32.9 million of Miscellaneous Revenue (Exhibit A-19, line 26).

Q. What is miscellaneous revenue?

A. Generally, miscellaneous revenue is revenue DTE Electric collects for non-electricity items. An example from the distribution side of the business is the revenue that the Company collects for the use of its poles by telephone and cable companies. For production, the bulk of the miscellaneous revenue is for interdepartmental use of production general and intangible plant, primarily by DTE Gas.

Q. Can you summarize your findings?

A. Yes. For the reasons stated above and consistent with the Staff recommendation in MPSC Case No. U-17032, the Commission should reject the classification of production costs using allocation methods because if the production capacity charge basis is reduced by 25%, Choice customers will only be paying for 75% of capacity costs, while standard customer will pay 100%. Furthermore, the Commission should reject the Staff's unsupported and seemingly arbitrary omission of valid production fixed costs from the basis for the production capacity charge. As an alternative to the Company's original basis, which could reasonably serve as the basis for the production capacity charge, I offer the amount derived using a bottom up approach and shown on Exhibit A-20. As explained above, this basis was derived using Staff's basis as the starting point and adding back the production fixed costs that were omitted in error. In total, I have adjusted Staff's base revenue requirement by $745.8 million (Per Exhibit A-20, line 41) and lowered the Company's capacity revenue requirement by $27.3 million (Exhibit A-20, line 42).

Q. Does this complete your rebuttal 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.	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

MICHAEL A. WILLIAMS

DTE ELECTRIC COMPANY
QUALIFICATIONS OF MICHAEL A. WILLIAMS

Line
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Q. Will you please state your name business address and by whom are you employed?

A. My name is Michael A. Williams. My business address is: One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Energy Corporate Services, LLC within Regulatory Affairs as Principal Financial Analyst.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of DTE Electric Company (DTE Electric or Company).

Q. What is your educational background?

A. I graduated from Michigan State University in 2004 with a Bachelor of Science degree in Economics.

Q. Have you completed any other courses of study?

A. Yes. I have attended multiple educational/training seminars regarding the electric utility industry throughout my career, including the Michigan State University Institute of Public Utilities Annual Regulatory Studies Program in 2007, 2008, 2011, 2014, and 2015.

Q. What work experience do you have?

A. From 2005 to 2007 I was employed at the Postal Regulatory Commission (PRC) in Washington, DC as part of the Rates, Analysis, and Planning division. In this role I was responsible for providing analysis and recommendations to PRC Commissioners regarding petitions filed by the United States Postal Service for things such as rate changes, new services, special contracts, and so on. I was also responsible for designing some of the PRC's recommended postal rates.

From 2007 until 2013 I was employed at the Indiana Utility Regulatory Commission (IURC) in Indianapolis, IN. I had positions of increasing responsibility, ultimately serving as a Senior Utility Analyst in the Electric Division. In this role I was responsible for providing analysis and recommendations regarding a wide range of electric regulatory filings made in Indiana.

I joined DTE Electric in 2013 as a Senior Business Financial Analyst in Regulatory Affairs. In April 2015, I was promoted to Principal Financial Analyst in Regulatory Affairs. My current responsibilities include rate development and administration of Company tariffs and rules. I also provide regulatory support to other business units.

Q. Have you testified previously before the Michigan Public Service Commission?

A. Yes, I have sponsored testimony and exhibits before the Michigan Public Service Commission (MPSC) in the following DTE Electric cases:

Case No.	Description
U-18014	DTE Electric 2016 General Rate Case Proceeding
U-17793	DTE Electric Biennial Review of its Amended Renewable Energy Plan
U-17767	DTE Electric 2014 General Rate Case Proceeding
U-17689	DTE Electric Public Act 169 of 2014 Filing

DTE ELECTRIC COMPANY
DIRECT TESTIMONY OF MICHAEL A. WILLIAMS

Line No.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to support the proposed residential capacity charge rate design and tariff language modifications for the residential rate schedules pursuant to the requirements of 2016 PA 341.

Q. Mr. Williams, are you sponsoring any exhibits?

A. Yes. I am sponsoring in part, the following exhibits:

Exhibit	Schedule	Description
A-11	2	Present (U-18014) and Proposed Rate Designs by Rate Schedule
A-12	1	Proposed Tariff Sheets

With respect to Exhibit A-11, Schedule 2, I am sponsoring the residential class which includes pages 2 through 10 of this exhibit. Company Witnesses Mr. Bloch and Ms. Holmes are sponsoring the remaining customer classes in Schedule 2. On Exhibit A-12, Schedule 1, I am sponsoring the proposed changes to the residential class. Witnesses Bloch and Holmes are sponsoring the remaining sheets contained in this exhibit.

Q. Were these exhibits prepared by you or under your direction?

A. Yes, they were.

Q. What is the basis for the Company's proposed residential rates in the proceeding?

A. The basis for the proposed power supply rates is the functionalized power supply cost of service study supported by Company Witness Mr. Lacey in his Exhibit A-

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14. Witness Lacey's Exhibit A-14 contains the power supply revenue requirement for each rate class (line 1), and how much of each revenue requirement relates to capacity (line 6).

Q. Can you explain how the revenue requirements provided by Witness Lacey were utilized to design the Company's proposed residential rates in this proceeding?

A. Within the power supply cost of service, Witness Lacey identifies two separate residential cost classes: "D1/Other" and "D2". All residential rate schedules except D2 are included in D-1/Other. For the D1/Other rate schedules the power supply revenue requirements (both capacity and non-capacity) were allocated based on each rate schedule's percentage contribution to the present D-1/Other power supply revenue. This is the same method of allocation used by both the Company and MPSC Staff in developing the approved D1/Other power supply rates in the Company's most recent rate case, Case No. U-18014.

For each residential rate schedule, the Company designed capacity and non-capacity power supply rates. To design the residential non-capacity rates, the non-capacity revenue requirement allocated to each rate schedule as described above was divided by the respective rate schedule's total power supply sales to develop an energy based non-capacity charge. The capacity charge(s) for each residential rate schedule were then calculated as the difference between the existing power supply rates and the non-capacity rate.

As supported and instructed by Company Witness Mr. Stanczak, Exhibit A-11, Schedule 2 reflects that bundled customers will be charged both the non-capacity and capacity power supply charges, while only the power supply capacity charges may be applicable to Electric Choice customers. As also supported and instructed by Witness Stanczak, in this case the Company is assuming that no Electric Choice customers will take capacity service from the Company. The capacity and non-capacity charges proposed in this case are designed such that the sum of the two pieces is equivalent to the existing bundled power supply rates. The table below illustrates this, using Rate Schedule D1:

Rate Schedule D1 Total Power Supply Rates: Current Versus Proposed (cents)

Line No	Charge	Current	Proposed	
1	Non-Capacity Charge	N/A	3.506	*Exh. A-11, Sch 2 p.2 line 2*
2				
3	Capacity Charges:			
4	First 17 KWH/Day	N/A	4.529	*Exh. A-11, Sch 2 p.2 line 4*
5	Excess	N/A	6.092	*Exh. A-11, Sch 2 p.2 line 5*
6				
7	Total Power Supply Rate:			
8	First 17 KWH/Day	8.035	8.035	*For proposed, line 1 + line 4*
9	Excess	9.599	9.599	*For proposed, line 1 + line 5*

The Company is not proposing any changes to its existing residential distribution rates.

Q. Are you presenting a comparison between rates approved in Case No. U-18014 and the rates you are proposing in this case?

A. Yes. Exhibit A-11, Schedule 2 shows the rates approved by the Michigan Public Service Commission on January 31, 2017 in Case No. U-18014, and the rates being proposed in this case to establish capacity charges. For the rate schedules I am sponsoring, the various billing components are listed in column (a), and the respective billing determinants, including units of measure, are listed in column (b). The billing determinants are the same billing determinants which were used to develop the Company's approved rates in the Commission's January 31, 2017 Order in Case No. U-18014, the Company's last approved rate case. The Company's existing rates, as approved in Case No. U-18014, are in column (c), and are used to calculate the present revenues in column (d). The rates proposed in this proceeding are in column (e), with the resulting revenues in column (f). As can be seen from comparing the present revenues in columns (d) and the proposed revenues in column (f), the rates proposed in this case are designed to be revenue neutral, and recover the same total revenue approved in Case No. U-18014.

Q. What data will be included in the new tariff sheets ?

A. Exhibit A-12, Schedule 1 contains the proposed tariff sheet changes to incorporate the capacity charges being proposed for each rate schedule.

Q. Does this complete 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 341 for	)	Case No. U-18248
DTE ELECTRIC COMPANY'S	)	
service territory.	)	

REBUTTAL TESTIMONY

OF

MICHAEL A. WILLIAMS

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF MICHAEL A. WILLIAMS

Line No.

Q. Will you please state your name business address and by whom are you employed?

A. My name is Michael A. Williams. My business address is: One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Energy Corporate Services, LLC within Regulatory Affairs as Principal Financial Analyst.

Q. Did you file direct testimony in this proceeding on behalf of DTE Electric Company (DTE Electric or Company)?

A. Yes, I did.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to rebut the Michigan Public Service Commission Staff (MPSC) proposed residential rate design.

Q. Are you sponosoring any rebuttal exhibits?

A. No, I am not.

Q. Staff Witness Mr. Revere's testimony on page 12 states, "Staff recommends that capacity-related costs be collected through summer on-peak kWh charges for rate schedules without demand charges, and through summer on-peak kW charges for rate schedules with demand charges." Do you agree with this proposal?

A. No. Staff's proposed residential rate design would fundamentally change the way the vast majority of residential customers are charged for electric service, as it would create mandatory time of day rates for all residential customers. Under Staff's proposal, the approximate 1.9 million full service Rate Schedule D1 Residential Service customers would be charged an incremental 13.866 cents per kWh for summer on peak energy consumption, which Staff defines as consumption during June-September, 7 a.m. through 11 p.m. Monday through Friday.

This fundamental change to the manner in which residential customers are charged for utility service should not be adopted by the Commission in this case for the following reasons:

- For rate design purposes, for several residential rate schedules, including Rate Schedule D1, Staff has assumed that the portion of residential usage that will be summer on peak usage will be equal to the historic average annual percentage of on peak usage for 2014-2016. Staff provides no analysis or testimony on how its rate design proposal will impact the amount of energy residential customers will use during the summer on peak period, or what affect any such change will have on the Company's revenue recovery, all of which should be carefully analyzed and considered before adoptiong such a rate design.
- Capacity cost recovery through power supply rates is being proposed to be broken out into separate capacity rates in this case for the first time, due to PA 341. However, capacity costs were not created by PA 341; they have historically been, and are currently, recovered through power supply rates. While the Company is simply proposing to "unbundle" the existing power supply rates into capacity and non-capacity, Staff's proposal would fundamentally change how the capacity costs are recovered from customers.
- While the Company offers several residential rate products which incorporate time of day and seasonal pricing that are available to residential customers on an

optional opt-in basis, Staff's proposal would force all residential customers to be subject to time of use pricing. Staff provides no analysis or testimony on the financial impact its residential rate proposal would have on individual residential customers (positive or negative). Staff also provides no analysis or testimony on the affect its residential rate design proposal would have on customer satisfaction, which in DTE Electric's opinion could diminish.

- Staff's proposed rate design contains other inconsistencies and apparent errors as well. For example, for Rate Schedules D1.2, D1.7, and D1.8, which all currently have time of day rates, Staff calculated its capacity charge billing determinant by using the Case No. U-18014 billing determinants for the time of use periods contained in those rates; however, Staff's proposed capacity charge summer on peak time period is different from the D1.2, D1.7, and D1.8 time of day pricing time periods, and thus the rate design is flawed. Staff also did not propose any capacity charge for Rate Schedules D1.1 and D5.

Based on the above, the Company does not believe this case should fundamentally change how residential customers are charged for electric service, and thus Staff's rate design proposal should be denied. The Company's proposed residential capacity and non-capacity rate design, whereby each residential rate schedule's charging structure is maintained, should be approved. Unlike the Company's residential rate design proposal, Staff's proposal would have significant impact on rate structure and on the individual rates and bills of the approximately 1.9 million D1 residential customers, as illustrated by the below table. If the Staff feels such a fundamental change should be considered it should be addressed in a general rate case and include the appropriate supporting studies which identify how these changes impact customer usage and behavior.

Rate Schedule D1 Total Power Supply Rates: Current, Company Proposed, and Staff Proposed (cents)

Line No.		Current	DTE Proposal[1]	Staff Proposal[2]
1	Non-Capacity Charge	N/A	3.506	N/A
2	First 17 KWH/Day	8.035	4.529	5.545
3	Excess	9.599	6.092	6.624
4	Summer On Peak Rate	N/A	N/A	13.866
5	**Total Power Supply Rate**[3]			
6	Summer On Peak:			
7	First 17 KWH/Day	8.035	8.035	19.411
8	Excess	9.599	9.598	20.490
9	Non-Summer On Peak			
10	First 17 KWH/Day	8.035	8.035	5.545
11	Excess	9.599	9.598	6.624

Notes:
1. DTE Proposal capacity rates are the "First 17 kWh/Day and "Excess" rates.
2. Staff Proposal capacity rate is the Summer On Peak Rate.
3. Total Power Supply Rate is the sum of the above components for each rate design proposal.

Q. Does this complete your rebuttal 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.	)	

QUALIFICATIONS

AND

REVISED DIRECT TESTIMONY

OF

ANGELA P. WOJTOWICZ

DTE ELECTRIC COMPANY
QUALIFICATIONS OF ANGELA P. WOJTOWICZ

Line No.

Q. What is your name, business address and by whom are you employed?

A. My name is Angela P. Wojtowicz. My business address is 414 S. Main Street, Suite 300, Ann Arbor, Michigan 48104. I am employed by DTE Electric Company (DTE Electric or Company).

Q. What is your current position with the Company?

A. I am the Director of the Generation Optimization department.

Q. What is your educational background?

A. I received a Bachelor of Science Degree in Nuclear Engineering from The University of Michigan in 1991. I also received a Master of Science Degree in Nuclear Engineering from The University of Michigan in 1992.

Q. Do you hold any certifications?

A. Yes. I am certified as a North American Electric Reliability Council (NERC) Certified System Operator for balancing and interchange. I also hold a Black Belt certification in Lean Six Sigma Business Management Strategy.

Q. What is your work experience?

A. After obtaining my Bachelor's degree from The University of Michigan in the spring of 1991, I was employed by Advent Engineering Services. During my employment at Advent, I worked as an engineering consultant performing mechanical and nuclear engineering design calculations and analyses for several electric utility company power plants across the country, both nuclear and fossil.

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I began my employment with The Detroit Edison Company in 1995 as a System Engineer at the Fermi 2 Nuclear Power Plant. As a System Engineer, I was responsible for performing system monitoring and inspections, establishing predictive and preventive maintenance, identifying and implementing system modifications and enhancements, performing system testing, writing maintenance and operations procedures, and troubleshooting system problems. In 2000, I began a developmental assignment at Fermi 2 as the Balance of Plant, System Engineering Lead Engineer, an assignment which was later made permanent. As the Lead Engineer, I was responsible for oversight of all of the Fermi 2 Balance of Plant systems and the direct supervision of several system engineers.

In 2004, I transferred to the Generation Optimization group. My areas of responsibility included analyzing power purchases and sales, including summer capacity purchases, managing Detroit Edison's financial transmission rights (FTR) portfolio, managing Detroit Edison's resource adequacy requirements with the Midwest Independent Transmission System Operator (MISO), preparing registration submittals for Detroit Edison's generation assets with MISO, preparing the Transmission and MISO Energy Market Expense exhibits for Detroit Edison's Power Supply Cost Recovery (PSCR) cases, and supporting the relevant witnesses in those Michigan Public Service Commission (Commission or MPSC) cases.

In 2007, I was promoted to Supervisor, Midterm Optimization, supervising all of my previous responsibilities and adding the responsibilities of administration of the REC portfolio to address Public Act 295 of 2008 (the "clean, renewable, and efficient energy act") and management of the Renewable Energy Certificate (REC) portfolio for the Company's voluntary GreenCurrents program.

In 2011, I was promoted to Manager, Wholesale Power, managing all of my previous responsibilities and adding the responsibility of managing the Company's wholesale power contracts. In 2013, my management responsibilities were expanded to include the Settlements group which is responsible for the validation and payment of all MISO transactions and power purchase agreements. In 2014, the Settlements Team was moved under another manager and I took on management of the Merchant Analytics Team which is responsible for the dispatch strategies and modeling and forecasting of the generation fleet. In 2015, I was promoted to my current role as Director of the Generation Optimization organization.

Q. What are your duties and responsibilities in your current position?

A. As the Director of Generation Optimization, I am responsible for the oversight and strategic direction of the Generation Optimization organization which acquires wholesale power electric supply to reliably and economically serve the energy and demand requirements of the Company's customers. The Generation Optimization organization includes the Merchant Operations Center, which is responsible for the dispatch of the Company's generation fleet in the wholesale energy market, the Merchant Analytics Team, which is responsible for the dispatch strategies and modeling and forecasting of the generation fleet, the Settlements Team, which is responsible for validation and payment all wholesale energy related transactions, and the Wholesale Market Development team, which is responsible for advocacy on behalf of the Company in the MISO market and development of infrastructure to integrate new energy assets and market changes into the Company's processes.

Q. Have you previously provided testimony to the Commission?

A. Yes. I sponsored testimony in the following DTE Electric cases:

U-15002-R	2007 Power Supply Cost Recovery Plan Reconciliation
U-15417-R	2008 Power Supply Cost Recovery Plan Reconciliation
U-15677	2009 Power Supply Cost Recovery Plan
U-15677-R	2009 Power Supply Cost Recovery Plan Reconciliation
U-16047	2010 Power Supply Cost Recovery Plan
U-16047-R	2010 Power Supply Cost Recovery Plan Reconciliation
U-16356	2009 Renewable Cost Reconciliation
U-16357	2010 Renewable Cost Reconciliation
U-16434	2011 Power Supply Cost Recovery Plan
U-16434-R	2011 Power Supply Cost Recovery Plan Reconciliation
U-16472	2010 General Electric Rate Case
U-16582	2011 Renewable Energy Plan Review and Amendment
U-16656	2011 Renewable Cost Reconciliation
U-16892	2012 Power Supply Cost Recovery Plan
U-16892-R	2012 Power Supply Cost Recovery Plan Reconciliation
U-17097	2013 Power Supply Cost Recovery Plan
U-17302	2013 Renewable Energy Plan Review and Amendment
U-17319	2014 Power Supply Cost Recovery Plan

DTE ELECTRIC COMPANY
REVISED DIRECT TESTIMONY OF ANGELA P. WOJTOWICZ

Line No.

Q. What is the purpose of your testimony in this proceeding?

A. The first purpose of my testimony is to demonstrate that capacity available to serve customers in Michigan is most likely diminishing below the industry acceptable reserve margins over the next few years. This testimony is provided in Part I, titled "Capacity Projections for MISO and DTE Electric", which includes: (1) a high level view of the capacity situation in the MISO region and MISO Local Resource Zone (LRZ) 7; (2) a projection of the Company's capacity position over the next few years; and (3) an explanation of the importance of certain implementation details of the State Reliability Mechanism. The second purpose of my testimony is to establish the capacity-related generation costs included in the Company's Power Supply Cost Recovery (PSCR) Factor and the benefit of energy and ancillary services sales from the Company's capacity resources, which is provided in Part II, titled "Capacity Costs and Energy Sales Benefit in the PSCR Mechanism".

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring the following exhibits:

Exhibit	Description
A-1	2016 OMS MISO Survey Results
A-2	Updated MISO Region Capacity View Years 2018-2021
A-3	MISO 2016/2017 Planning Resource Auction Results
A-4	MISO 2017/2018 Preliminary Planning Resource Auction Data
A-5	MISO Zone 7 Capacity Projection PY18-PY21
A-6	DTE Electric Capacity Position Projection PY18-PY21
A-7	Capacity Queue Example
A-8	Projected 2017 PURPA Capacity-Related Generation Cost

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A-9 REVISED Projected 2017 PA295 Capacity-Related Generation Cost

A-10 REVISED Projected 2017 Capacity-Related Generation Cost & Energy Sales Revenue Net of Fuel Cost

PART I – CAPACITY PROJECTIONS FOR MISO AND DTE ELECTRIC

Q. How does MISO establish resource adequacy reliability requirements?

A. Each year MISO establishes a Planning Reserve Margin (PRM), which is the amount of capacity above the expected weather-normalized peak demand to reliably serve load. A PRM is expected to maintain reliable operation while meeting unforeseen events such as extreme weather and unexpected capacity outages. The PRM is established by performing a Loss of Load Expectation (LOLE) study which considers factors including, but not limited to: generator forced outage rates, generator planned outages, expected performance of load modifying resources, load forecasting uncertainty, and transmission system import and export capabilities. The PRM is established using a LOLE of 0.1 day per year, which is fairly standard in the industry.

Q. How does MISO implement its resource adequacy requirements established in its Tariff?

A. MISO's resource adequacy requirements are annual and implemented for the prompt year only. Every year, Load Serving Entities (LSE) in MISO are required to demonstrate compliance with their Planning Reserve Margin Requirement (PRMR), which is their forecasted peak demand (coincident with the MISO's peak demand) plus the required PRM. PRMR compliance requirements are executed in the spring immediately prior to the planning year beginning on June 1. MISO LSEs must meet their PRMR by submitting a Fixed Resource Adequacy Plan (an LSE's plan showing rights to sufficient resources to meet its PRMR), purchasing capacity through MISO's Planning Resource Auction (PRA), or paying a capacity deficiency charge. Due to its short-term and prompt horizon execution, MISO's PRA does not guarantee the availability of capacity and can actually result in a capacity shortage situation. If all LSEs properly plan for the long-term capacity needs of their customers, the PRA works as a balancing auction for the prompt year by providing a means to buy and sell small amounts of capacity needed as a result of normal variances in load and generation. However, when LSEs rely on the PRA for the full capacity needs of their customers, there is the high likelihood that there will be insufficient capacity to reliably serve load.

Q. How does MISO establish requirements for local reliability?

A. MISO developed Local Resource Zones (LRZs) based on criteria including electrical boundaries, state boundaries, transmission interconnections and geographic boundaries. There are ten LRZs within MISO and the Company's service territory is in LRZ 7, which is comprised of the majority of lower peninsula Michigan. As part of MISO's annual LOLE study, the Capacity Import Limits (CIL) and Capacity Export Limits (CEL) of each LRZ are determined along with the Local Clearing Requirement (LCR), which is the minimum amount of unforced capacity (the amount of capacity assigned to a particular resource utilizing historic availability) that must be physically located within a LRZ while fully utilizing the CIL of the LRZ. Simply stated, to reliably serve load a minimum amount of capacity must be located near the load, due to the limitation of the transmission system to import additional capacity. MISO enforces the LCRs, CILs and CELs using a multi-zone optimization methodology and commits capacity up to the PRM requirements of each LSE when conducting the PRA. This ensures that sufficient resources are committed, if available, in each LRZ to reliably serve load. The PRA Auction Clearing Price (ACP) will be set to the Cost of New Entry (CONE) when there is insufficient capacity to meet the LCR of a particular zone, or the total PRMR for the MISO footprint. The short term of the MISO PRA, combined with the deficiencies with the shortage pricing of CONE based on a simple cycle combusting turbine generator is not likely to result in the investment of needed baseload generating units to replace retiring baseload generating units.

Q. What is the MISO proposed Competitive Retail Solution (CRS) and its current status?

A. In 2016, MISO developed a proposed Competitive Retail Solution (CRS) to address the resource adequacy needs of competitive retail demand. In MISO, the competitive retail demand consists of the entire state of Illinois load and the 10% of Michigan load on electric choice. The CRS proposal included a Forward Resource Auction (FRA) which was a 1-year auction to be held three years in advance for competitive retail demand. The CRS also included a Prevailing State Compensation Mechanism (PSCM) that states could elect in lieu of the FRA, which would have given the option to Alternative Electric Suppliers (AESs) to provide firm forward capacity for their customers, or allow the capacity needs of their customers to be met by the designated utility. MISO submitted the CRS proposal to the Federal Energy Regulatory Commission (FERC) on November 1, 2016 requesting approval of the CRS to be effective March 1, 2017. On February 2, 2017 the FERC rejected the CRS proposal with the main reason that the CRS would bi-furcate the MISO capacity market because it would apply only to a small portion (less than 10 percent) of the load within

MISO. MISO announced on February 24, 2017 that they will not seek rehearing of FERC's order due to passage of legislation in Michigan and Illinois.

Q. What does FERC's rejection of the CRS mean for this case?

A. In this case the MPSC initially ordered the Company to explain whether the capacity mechanisms described in Sections 6w(1) and (2) of Act 341 are more cost-effective, reasonable, and prudent than would be the MISO's capacity forward auction. Since the MISO proposed CRS, including the FRA, was rejected by the FERC and MISO is not seeking rehearing of FERC's order (as announced on February 24, 2017), there will most certainly not be a resource adequacy tariff in effect that includes a capacity forward auction or a PSCM by September 30, 2017. Thus, it is my understanding of PA 341 that the MPSC will need to establish a State Reliability Mechanism (SRM).

Q. What is MISO's assessment of the capacity resources in the entire MISO region through 2021?

A. MISO's latest regional resource assessment (2016 OMS MISO Survey Results, Exhibit A-1) shows projections of potential capacity shortages starting in 2018 and worsening through 2021. Those projections include the announced potential retirement of the Clinton and Quad Cities nuclear plants at the time the survey was performed. Since then, legislation was passed in Illinois that may defer the retirement of those nuclear plants. The projections in Exhibit A-2 assume those retirements are postponed until at least the 2022-2023 planning year. Another significant change since the MISO survey is the announced retirement of the Palisades nuclear plant in 2018. Palisades was assumed to be in service in the MISO survey results. The net impact of these two retirement assumption changes maintains projected capacity

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shortages across MISO as shown in the Updated MISO Region Capacity Projection (Exhibit A-2).

Q. What is the projection of capacity in MISO LRZ 7 over the next few years?

A. MISO's LRZ 7 currently has insufficient capacity to meet its PRMR without relying on imported capacity from the rest of the MISO region. The MISO 2016/2017 Planning Resource Auction Results (Exhibit A-3) show that in 2016 LRZ 7 was already short of meeting its PRMR by 791 MW resulting in the reliance on capacity from outside of the state to reliably serve load in Michigan. The total amount of capacity available in LRZ 7 was 21,615 MW while the PRMR was 22,406 MW. The MISO 2017/2018 Preliminary Planning Resource Auction Data (Exhibit A-4) shows that LRZ 7 will likely again be short of meeting its PRMR, even after the addition of Wolverine's Alpine plant in 2016, and will likely continue to rely on capacity imported from outside of the state. The latest regional resource assessment (2016 OMS MISO Survey Results, Exhibit A-1) shows projections of potential capacity shortages in LRZ 7 starting in 2018 and continuing through 2021. The retirement of the Palisades nuclear plant will worsen the capacity situation in LRZ 7 by approximately 800 MW as shown on Exhibit A-5. With potential shortages of capacity in the entire MISO region, there will likely be insufficient available capacity to import into the state. This demonstrates the importance of having reliable capacity within the LRZ 7.

Q. What is the Company's projected capacity position over the next few years?

A. The Company's projected capacity position, relative to its PRMR, is shown on Exhibit A-6. This projection was developed using the latest MISO PRMR and current

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assumptions related to the Company's generation resources. The Company is projecting to have just enough capacity to meet the reliability needs of its current bundled customers in planning year 2019/20 through 2021/22. The Company is projecting a small capacity shortage in planning year 2018/19 of approximately 2-3% (200-300 MW) mainly due to the fire at the Company's St. Clair power plant in August of 2016 and the associated trailing impact of that unavailability on MISO accredited capacity. The Company is currently working on options to fill this shortage. The shortage is expected in planning year 2018/19 due to MISO's capacity testing deadline for the planning year. Therefore, the Company does not have excess capacity in the short-term to meet the reliability needs of additional customers that may either return to the Company as bundled customers, or alternatively as capacity only customers.

Q. How can the Company ensure reliability over the next 4 years as customers either return to the Company or pay the Company a capacity charge under Section 6w of Act 341?

A. The Company can maintain reliability by bringing customers back to firm service if/as capacity becomes available. If capacity is not available then current Electric Choice customers returning to the Company for capacity, will be placed on interruptible service and pay the Company a capacity charge consistent with that interruptible service, as discussed in more detail by Company Witnesses Messrs. Stanczak and Bloch. As the Company builds, develops, or acquires sufficient capacity, customers temporarily on interruptible service will be returned to firm service.

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Q. How will the Company determine when customers on temporary interruptible service will go to firm service?

A. The Company will establish a capacity queue as also discussed by Witnesses Stanczak and Bloch. Customers will be placed into the queue based on their return date. If more than one customer selects the same return date, priority of those customers will be determined by the date that the Company received each customer's notice of their intent to take capacity service from the Company. Customers in the capacity queue will be placed on firm service at the beginning of each MISO planning year (June 1) based on the amount of available excess capacity the Company has for that planning year. An example of such a queue is provided as Exhibit A-7. Customers will be notified of their pending firm service in late April or early May, after the MISO PRA for the prompt planning year beginning on June 1.

Q. How is the Company planning to provide capacity for Electric Choice customers returning to the Company for capacity?

A. It is my understanding that under Act 341, the Company will not know its capacity obligation from Electric Choice customers returning to the Company for capacity beginning June 1, 2018 and the subsequent 3 planning years until some period of time after the seventh business day of February in 2018 when the Alternative Electric Suppliers (AES) are obligated to demonstrate their capacity for those 4 planning years to the Commission. If there is insufficient time for the Company to build, develop, or acquire sufficient capacity for Electric Choice customers returning 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 of those Electric Choice customers. If MISO's PRA results in insufficient capacity, the

Company will provide interruptible service (as explained by Witness Stanczak) to serve the capacity obligation of those customers in the capacity queue. It is important that the Commission notify the responsible utility as soon as practical after the 7th business day of February 2018 of any additional capacity obligations the utility will have as a result of any AES failure to demonstrate sufficient capacity, so the utility can prudently plan for capacity.

Q. How will the Company serve the capacity obligations of Electric Choice customers that provide the Company with four years notice prior to returning?

A. Electric Choice customers that provide four years notice prior to returning to the Company for capacity are expected to have firm service when they return to the Company. The Company believes that four years is sufficient time to build, develop, or acquire capacity.

Q. What obligations does MISO place on LSEs using interruptible load as a capacity resource?

A. Interruptible load that is registered with MISO to meet resource adequacy capacity requirements is referred to as a Demand Response (DR) resources and must perform during MISO declared capacity emergencies. The penalty imposed by MISO on LSEs for DR non-performance consists of the Real-Time Locational Marginal Price (RT LMP) of the associated market node for the deficient energy below target, applicable Revenue Sufficiency Guarantee (RSG) payments, and potential loss of capacity market payments.

Q. What penalty should the Company impose on its customers that are on

interruptible tariff rates if they fail to curtail load when called upon by the Company?

A. All customers on interruptible tariff rates, both customers that signed up for interruptible rates and customers that are on interruptible rates due to insufficient capacity, should be charged for non-performance consistent with penalties imposed by MISO. Specifically, the penalty for failure to curtail should consist of an energy penalty and capacity penalty, if applicable, as follows:

Failure to Curtail Penalty = Energy Penalty + Capacity Penalty
where
Energy Penalty = MW of load that failed to curtail x RT LMP + RSG
Capacity Penalty = MW of load x ACP x Remaining # of days in Planning Year

Keeping the non-performance penalty the same for the retail customer as that imposed on the utility by MISO, essentially a pass through penalty, will hold firm customers financially harmless.

Q. How should the Capacity Obligation in Section 6w of 2016 PA 341 be defined?

A. 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

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for resource adequacy.

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 allocating the appropriate forecasted coincident peak demand for those customers to its own forecasted coincident peak demand.

PART II – CAPACITY COSTS AND ENERGY SALES BENEFIT IN THE PSCR MECHANISM

Q. Section 6w(3)(A) of Act 341 requires that the capacity charge include capacity-related generation costs included the Company's PSCR Factor, as well as other rates and surcharges. What are the capacity-related generation costs included the Company's PSCR Factor?

A. The Company's PSCR Factor includes capacity-related generation costs associated with PURPA power purchase agreements, PA295 Company-owned renewable energy systems, PA295 renewable energy contracts, and capacity purchases.

Q. How did the Company project the 2017 capacity-related generation costs for PURPA power purchase agreements as included in its PSCR plan filing on September 30, 2016 in Case No. U-18143?

A. The Company's PURPA contracts have three rate components; fixed, operation and maintenance (O&M), and variable. The projections for both the fixed and O&M

components were included in the capacity-related generation costs. The total projected 2017 PURPA capacity-related generation cost is approximately $23.8 million as shown on Exhibit A-8.

Q. What costs associated with PA295 company-owned renewable energy systems and power purchase agreements are included in the PSCR?

A. The portion of the cost of PA295 company-owned renewable energy systems that is passed through the PSCR mechanism is the lower of the Transfer Price approved for the renewable energy systems or the levelized cost of energy calculated for the renewable energy system. The portion of cost of PA295 power purchase agreements (i.e. non-Company owned) that is passed through the PSCR mechanism is the lower of the Transfer Price approved for the power purchase agreement or the contract price of the agreement.

The Transfer Price is a proxy for the non-renewable capacity and energy that would be passed on to the customer if the renewable energy resource was not developed. The relevant statute explains that when setting the transfer price, the Commission shall consider factors including, but not limited to, projected capacity, energy, maintenance, and operating costs, information filed under Section 6j of 1939 PA 3 (MCL 460.6j), and wholesale market data, including but not limited to, locational marginal pricing.

Q. How did the Company project the 2017 capacity-related generation costs for PA295 company-owned renewable energy systems and power purchase agreements?

A. The capacity-related generation cost for PA295 company-owned renewable energy systems and power purchase agreements is the total cost recovered in the PSCR mechanism less the variable/fuel cost associated with the renewable energy system. The variable/fuel prices associated with wind and solar renewable energy systems are zero since wind and sun energy have no variable/fuel cost. The variable/fuel prices for non-Company owned renewable energy systems are the approved Transfer Price variable price components for each specific renewable energy system. Using the previously described criteria, the total projected 2017 PA295 capacity-related generation cost is approximately ~~$213~~ $203 million as shown on Exhibit A-9 REVISED.

Q. How did the Company project the 2017 cost of capacity purchases?

A. The Company is not projecting any capacity purchases in 2017 so the value shown on Exhibit A-10 REVISED , line 6 is zero.

Q. How did the Company calculate the projected 2017 energy sales revenue net of projected fuel costs per Section 6w(3)(B) of Act 341?

A. Section 6w(3)(B) of Act 341 requires that the revenue, net of projected fuel costs, from energy market sales, off-system energy sales, ancillary services sales, and energy sales under unit specific bilateral contracts be subtracted from the capacity charge. To calculate the energy sales revenue net of projected fuel costs, first the revenue associated with energy sales from the Company's generation resources was determined, which is any excess generation sold into the MISO energy market after serving the Company's bundled load. Next, the revenue associated with ancillary services provided by the Company's generation resources was determined, then the portion of those ancillary services associated with the energy sales was determined by multiplying by the ratio of energy sales volume to total generation volume.

Q. What is the projected revenue associated with energy sales from the Company's generation resources in 2017?

A. In the Company's 2017 PSCR Plan (U-18143), there are 3,334 GWh of projected energy market sales in 2017 with associated revenue of $110 million as shown on Exhibit A-10 REVISED, lines 11 and 12, respectively.

Q. Is the Company projecting any off-system energy sales or sales under unit specific bilateral contracts in 2017?

A. No. These values are shown as zero on Exhibit A-10 REVISED, lines 13 and 14.

Q. What is the projected ancillary services revenue associated with energy sales from the Company's generation resources in 2017?

A. The Company's generation resources received revenue for providing the following ancillary services: regulation reserves, spinning reserves, and supplemental reserves (all settled via MISO's energy and ancillary services market) and reactive reserves (settled per Schedule 2 of the MISO tariff). The Company's 2017 PSCR Plan projected that Company's generation resources would generate $1.63 million of revenue associate with regulation, spinning, and supplemental reserves and $14.97 million of revenue associated with Schedule 2 reactive reserves. The portion of these ancillary services revenues associated with the energy sales from the Company's generation resources in 2017 is determined by multiplying the total ancillary services revenue by the ratio of the energy sales volume to the total projected generation volume (3,334 GWh / 44,509 GWh), which amounts to $122,000 for regulation, spinning, and supplemental reserves revenue as shown on Exhibit A-10 REVISED, line 15 and $1.121 million for reactive reserves revenue as shown on Exhibit A-10 REVISED, line 16.

Q. What is the total projected energy sales revenue including ancillary services in 2017?

A. The total projected energy sales revenue including ancillary services in 2017 is $111.3 million as shown on Exhibit A-10 REVISED, line 17.

Q. What is the projected fuel and fuel related cost required to generate the projected energy and ancillary services sales from the Company's generation resources in 2017?

A. The projected fuel and fuel related cost required to make the energy and ancillary services market sales is projected by calculating a fleet average generation fuel price and multiplying it by the energy sales volume. The fleet average generation fuel price is calculated by summing the total projected fuel, emission allowance, and chemical costs for the Company's generation fleet ($829.6 million as shown on Exhibit A-10 REVISED, line 24) then dividing by the total projected generation volume (~~41,132~~ 44,509 GWh as shown on Exhibit A-10 REVISED, line 25) which results in a generation fuel price of ~~$20.17~~ $18.64/MWh as shown on Exhibit A-10 REVISED, line 26. The generation fuel price is multiplied by the projected energy market sales volume to get a projected 2017 energy sales fuel cost of ~~$67.2~~ $62.1 million as shown on Exhibit A-10 REVISED, line 28.

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Q. What other costs are associated with the projected energy sales described above that should be netted against the revenue?

A. MISO incurs costs when providing the following services including, but not limited to: 1) market modeling and scheduling functions; 2) market bidding support; 3) locational marginal pricing support; 4) market settlements and billing; 5) market monitoring functions; and, 6) simultaneous co-optimization for the scheduling and enabling of the least-cost, security-constrained commitment and dispatch of Generation Resources to serve Load and provide Operating Reserves in the MISO Balancing Authority Areas while also establishing a spot energy market. MISO recovers these Energy and Operating Reserve Markets Support Administrative Service Cost through a recovery adder filed as Schedule 17 in the MISO tariff. The projected Schedule 17 rate for 2017 is $0.0735/MWh, so the Schedule 17 admin fees associated with the 3,334 GWh of projected energy market sales in 2017 is $245,000 as shown on Exhibit A-10 REVISED, line 30.

Q. What is the Company's projected energy sales revenue net of projected fuel costs per Section 6w(3)(B) of Act 341 for 2017?

A. The total projected 2017 energy sales revenue of $111.3million, net of ~~$67.2~~ $62.1 million in fuel related costs and $245,000 in Schedule 17 admin fees equates to ~~$43.9~~ $48.9 million energy sales revenue net of fuel related costs as shown on Exhibit A-10 REVISED, line 32. This amount was provided to Company Witness Mr. Lacey to develop his capacity related cost of service.

Q. Does this complete 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 341 for	)	Case No. U-18248
DTE ELECTRIC COMPANY'S	)	
service territory.	)	

REBUTTAL TESTIMONY

OF

ANGELA P. WOJTOWICZ

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF ANGELA P. WOJTOWICZ

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Q. Are you the same Angela P. Wojtowicz who previously offered testimony in this proceeding?

A. Yes, I am.

Q. What is the purpose of your rebuttal testimony in this proceeding?

A. The purpose of my testimony is to rebut issues raised by the following intervenors in this case:

- MPSC Staff Witness Mr. Revere,
- Energy Michigan (EM) Witness Mr. Zakem,
- Energy Michigan Witness Mr. Jennings, and
- Association of Businesses Advocating Tariff Equity (ABATE) Witness Mr. Dauphinais

Specifically, I will be rebutting: (1) the failure to include the cost of P.A. 295 renewable energy along with the sales revenue in the capacity charge , (2) the improper use of Cost of New Entry (CONE) for the capacity charge, (3) the incorrect claim that DTE's generating facilities do not contribute to lower hourly market prices, (4) the incorrect conclusion that the MISO Tariff prohibits the reassignment of PRMR requirements from one LSE to another, (5) the dangerous proposal to use potential MISO Planning Resource Auction purchases to meet future capacity demonstrations, and (6) the incorrect projection and application of DTE energy market sales.

Q. Do you agree with Witness Revere's use of P.A. 295 Transfer Prices to determine the capacity-related portion of P.A. 295 renewable generation to be included in the SRM capacity charge?

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A. No. Witness Revere uses only his calculated fixed cost component of the Transfer Price to determine the portion of cost to include the SRM capacity charge while still including the wholesale market revenue from those sales. This method fails to recognize that the Transfer Prices were merely intended to be a cost recovery mechanism (via the PSCR mechanism) for the capacity <u>and</u> energy value of the renewable generation, with the renewable value (or Renewable Energy Credit) recovered through the renewable energy surcharge. Even though the true variable cost of wind and solar resources is essentially zero, the energy component of the Transfer Price is the variable energy cost that the Company <u>must</u> pay to be able to sell the renewable energy into the wholesale market and receive the MISO Locational Marginal Price (LMP) as revenue. Because the Energy Market Sales (Exhibit A-10, line 12) includes the MISO wholesale market revenue from renewable energy sales, it is critical that the energy component of the Transfer Price be included in the capacity charge. Neglecting to include the energy component of the Transfer Price in the capacity charge <u>but at the same time</u> including the revenue from the associated wholesale market energy sales, as Witness Revere proposes, provides non-bundled customers with the benefit of the energy sales without paying the costs associated with them. Witness Revere himself states that to remove the costs above a CT from the capacity charge and then apply an offset would be double counting the offset, then he does exactly that by lowering the total cost of the company's capacity yet applying the energy benefit that the capacity provides. Non-bundled customers should not receive the benefit of energy sales that they do not fully share in paying the associated costs. This would result in full-service customers subsidizing these customers.

Q. Do you agree with Witness Revere's opinion that the proper cost of capacity is the Cost of New Entry (CONE), or the cost to build a Combustion Turbine (CT) in the context of the SRM capacity charge?

A. No. Witness Revere claims that CONE based on a combustion turbine is the proper cost of capacity, as it is intended to meet peak demand. Witness Zakem similarly makes a claim that CONE is a fair compensation for capacity and Witness Dauphinais recommends that CONE be the high end of a range of possible capacity prices. All of these witnesses fail to recognize that incremental peak capacity of combustion turbines alone does not provide reliability to Michigan customers. AES customers, just like utility full-service customers, require capacity during all times throughout the year, not only during peak hours. Suggesting that AES customers requiring capacity from the utility should only pay for peak incremental capacity is suggesting that they do not need energy service at all during other times of the year, which is ludicrous. Incremental capacity will be needed *along with the existing capacity* to maintain electric reliability in Michigan for all customers. Any AES customer taking capacity service from a utility will be benefitting from all of the utility's capacity; therefore, the true cost of all utility capacity should be included in the capacity charge.

Witness Revere is correct in his conclusion that the additional capital cost (above the cost of a CT) to build other types of generating assets – like a combined-cycle gas turbine generator – are associated with lower energy costs. However, contrary to Witness Revere's proposal, this is exactly why CONE based on a CT is <u>not</u> the proper cost to include in the SRM capacity charge. MCL 460.6w requires that the revenue from energy and ancillary sales, net of fuel costs, be subtracted from the capacity charge Cost of Service (COS). Most of the revenue from energy and ancillary service sales are from base-load generating assets which lower the wholesale energy market prices that benefit all customers, including AES customers. Thus, the full capacity costs associated with any generation asset (in his example the CC) should be included in the SRM, as the law recognizes that the energy benefit of sales revenues will offset the capacity cost. In the case of a CC, those energy sales would be greater than those of a CT, offsetting more of the capacity cost. If the law did not intend this, then it would not have discussed crediting the revenues of energy sales against the capacity cost. The Company would have very little to no energy revenue with only CTs.

Q. Do you agree with Witness Dauphinais' statement that DTE's generation facilities do not contribute to lower hourly market prices?

A. No. Witness Dauphinais recognizes that MISO's hourly market prices for energy are set based on the highest incremental energy offer, but fails to recognize that the incremental offer would be higher without DTE's generation in the supply offers. DTE's baseload plants with lower dispatch cost and its renewable wind and solar resources with zero dispatch cost suppress the wholesale energy prices in Zone 7. All load serving entities, including AESs, benefit from the lower wholesale energy market prices from DTE. This is one more reason why the full capacity costs of DTE's fleet should be included in the SRM and not the incremental cost of a CT.

Q. Do you agree with Witness Zakem's conclusion that the MISO Tariff prohibits DTE, as the Electric Distribution Company (EDC), from reassigning PRMR requirements from one LSE to another?

A. No. In fact, I would argue that the MISO Tariff actually addresses the issue of reassigning capacity charges related to customer switching.

> The Transmission Provider will use Coincident Peak Demand, Local Resource Zone Peak Demand, and Energy forecasts that are submitted by an EDC in combination with allocation procedures that are agreed to by the applicable LSEs. These procedures will allow the Transmission Provider to initially allocate appropriate portions of the total forecasted Coincident Peak Demand and Local Resource Zone Peak Demand to each LSE as applicable pursuant to 69A.1.2.1, ***and to re-assign ZRC-related charges caused by customer switching between suppliers to the appropriate LSE***. (emphasis added)

The existing MISO Peak Load Contribution (PLC) process currently utilized by DTE every day allows for the reassigning of MISO capacity charges from one LSE to another. If a customer were to be charged a capacity charge by the utility, DTE would reduce that customer's Alternate Electric Supplier's (AES) peak load contribution by the appropriate amount on the effective date. I have confirmed that this method would work under the current MISO Tariff in a discussion with MISO personnel.

Q. Is there another flaw in Witness Zakem's claim regarding MISO reassigning capacity obligations from an AES to DTE?

A. Yes, Witness Zakem confuses and conflates the wholesale capacity obligation at MISO with the retail capacity obligation in the State of Michigan. Under the latter, an AES must demonstrate to the MPSC that it has the capacity resources necessary to serve its retail load four years into the future. That requirement is separate and distinct from the wholesale obligations at MISO. Clearly it would be possible for an AES that did not demonstrate capacity to the MPSC four years in advance of the planning year to serve the energy needs of a retail customer in Michigan. However, that AES's customers would be subject to the host utility's capacity charge for retail capacity service.

Line
No.

Q. Do you agree with Witness Zakem's conclusion that MISO Zone 7 will continue to meets its LCR with no additional capacity other than what is needed for replacement of retiring resources?

A. No. Witness Zakem's conclusion that Zone 7 will continue to meet its LCR is short-sighted in that it assumes the utilities will replace all retiring capacity resources with new Zone 7 capacity resources. The LCR is currently met because the utilities currently provide more than their load ratio share of the LCR, leading to excess capacity above the LCR. This will likely not be the case going forward. The Company only plans for its bundled service customers, so as excess capacity is retired, it will not be replaced. Additionally, the Company will continue to look for economic ways to meet the capacity needs of its bundled service customers, which may include capacity resources outside of Zone 7.

Q. Do you agree with Witness Zakem's proposal that future auction purchases can be used for demonstration in the out years?

A. No. Proposing to meet a capacity demonstration for the future with the MISO Planning Resource Auction (PRA) is a huge risk to reliability and contrary to the purpose of Act 341. The MISO PRA does not ensure the existence of adequate capacity resources and can actually result in a shortage of capacity resources. To claim that a ***potential*** purchase of capacity in the future is a demonstration of future capacity is not a demonstration at all. The Commission should reject such a proposal.

Q. Do you agree with Witness Jennings' projection of energy market sales?

A. No. Witness Jennings developed a projection of the output of the Company's power plants and the plants associated with the company's power purchase agreements.

Line
No.

Witness Jennings then translated the generation forecast into Energy Market Sales revenue using modeled energy market prices and historical LMPs. The generation forecast assumptions used by Witness Jennings's are flawed because they do not consider unit capabilities, fuel blends, planned outages, power purchase agreement terms and operational conditions, etc., which result in output projections that are not reflective of the Company's generation and power purchase agreement portfolio. Even if you assume Witness Jennings' projection of DTE's generation portfolio is accurate, he then incorrectly translates his entire generation output projection to Energy Market Sales. The Company must use the generation from its power plants and power purchase agreements to first serve its full-service customers who pay the true full cost of this power. If the Company has excess generation output in any given hour after meeting the load requirements of is full-service customers, then and only then does the Company make wholesale energy sales. It is unreasonable to suggest that the Company has energy market sales in hours in which it is a net energy buyer from the energy market. Additionally, Witness Jennings appears to have incorrectly ignored the energy costs associated with the Company's P.A. 295 renewable generation and its power purchase agreements. Similarly, Witness Jennings appears to have incorrectly used the gross ancillary service sales in his capacity charge calculation rather than the net ancillary services sales. These one-sided calculations further the attempt of free-riding off utility generation resources.

Q. Does this complete your rebuttal testimony?

A. Yes, it does.

JUDGE EYSTER: Ms. Donofrio, would you like to be next?

MS. DONOFRIO: Certainly. Staff filed the -- Staff Witness Heather A. Cantin filed a cover page and eight pages of questions and answers. She did not sponsor any exhibits.

Staff Witness Eric W. Stocking filed direct testimony and qualifications, consisting of a cover page and ten pages of questions and answers, and likewise, he did not sponsor any exhibits.

Would you like me to move to bind those into the record now or call our live witness first and then bind them all at the end?

JUDGE EYSTER: Why don't we just do those two.

MS. DONOFRIO: Staff moves to bind in the direct testimony of Heather Cantin and Eric Stocking pursuant to stipulation of the parties.

JUDGE EYSTER: Any objections?

Hearing none, the testimony is bound in.

(Testimony bound in.)

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S T A T E OF M I C H I G A N

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

QUALIFICATIONS AND DIRECT TESTIMONY OF

HEATHER A. CANTIN

MICHIGAN PUBLIC SERVICE COMMISSION

July 21, 2017

QUALIFICATIONS OF HEATHER A. CANTIN
CASE NUMBER U-18248
PART I

Q. Please state your name, address and occupation.

A. My name is Heather A. Cantin and my business address is 7109 West Saginaw Highway, Lansing, Michigan 48917. I am employed by the Michigan Public Service Commission (MPSC) as a Departmental Analyst in the Resource Adequacy and Retail Choice Section of the Financial Analysis and Audit Division (FAAD).

Q. Please describe your educational background.

A. I earned a Bachelor of Business Administration majoring in Marketing and minoring in General Business from Western Michigan University in 2007. I have attended utility regulatory sessions sponsored by the National Association of Regulatory Utility Commissioners and completed the two-week Annual Regulatory Studies Program at Michigan State University. In addition, I attend the Michigan Forum sponsored by the Institute of Public Utilities each year and have attended various in-state conferences on electric choice issues. In the fall of 2012, I attended the two-day National Energy Marketers Association (NEM) Fall Leadership Roundtable Forum at Michigan State University, which included discussions on electric and gas choice programs in the state. Also, I attended the 18th annual National Energy Restructuring Conference sponsored by NEM in Washington D.C., which included a diverse group of stakeholders with presentations and discussions on electric and gas choice programs throughout the United States.

Q. Please describe your professional background with the state of Michigan.

QUALIFICATIONS OF HEATHER A. CANTIN
CASE NUMBER U-18248
PART I

A. I started my employment with the state of Michigan in March 2011 with the Michigan Public Service Commission as a Departmental Analyst under the Financial Analysis & Customer Choice Section of the Regulated Energy Division working on customer choice related issues. Currently, I am a senior level Departmental Analyst in the Resource Adequacy and Retail Choice Section of FAAD.

Q. Please describe your responsibilities in the Resource Adequacy and Retail Choice Section of the MPSC.

A. I am responsible for all aspects of the licensing process pertaining to applications filed by Alternative Electric Suppliers (AES) and Alternative Gas Suppliers (AGS). I review the AES and AGS applications to determine if they meet the Commission's requirements and then provide a recommendation to my manager, director and the Commission. Also, I continuously update the gas and electric choice pages of the MPSC's website, as well as maintain and update Michigan's natural gas price comparison website, www.mi.gov/CompareMIGas. I am responsible for responding to all aspects of supplier, utility, and customer issues on both the gas and electric choice programs. My duties also include overseeing the collection and reporting of Code of Conduct Complaints for all electric providers, reviewing alternative suppliers' marketing materials for residential and small commercial customers, and maintaining supplier files. Additionally, I assist the Commission on matters relevant to the operations of the customer choice programs. Furthermore, I perform a variety of other division-wide functions such as collecting annual financial utility reports and forms, preparing the annual

QUALIFICATIONS OF HEATHER A. CANTIN
CASE NUMBER U-18248
PART I

Public Utility Assessment (PUA) Report and Status of Electric Competition Report.

Q. Have you previously participated in any Commission cases?

A. Yes. I have been involved or participated in the following cases:

Case No.	Company	Description
U-16513:	Michigan Gas Utilities	Reservation Charge
U-16794:	Consumers Energy	Rate Case (ROA Tariff Changes)
U-16855:	Consumers Energy	Gas Rate Case
U-16969:	Continental Energy Systems	Merger & Acquisition (SEMCO)
U-17047:	DTE Gas Company	*Ex Parte* Gas Choice Tariff Changes
U-17087:	Consumers Energy	Rate Case (ROA Tariff Changes)
U-17131:	DTE Gas Company (GCR)	Reservation Charge
U-17148:	HomeWorks Tri County	*Ex Parte* Choice Tariff Changes
U-17137:	Nordic Marketing, LLC	AES License Revocation
U-17273:	Michigan Gas Utilities	Rate Case (Gas Choice Tariff Changes)
U-17274:	UPPCO	Rate Case (ROA Tariff Additions)
U-17332:	DTE Gas Company (GCR)	Reservation Charge
U-17432:	Cloverland Electric Co-Op	Complaint Case
U-17487:	DTE Gas Company	*Ex Parte* Gas Choice Tariff Changes
U-17580:	Commission's own motion	Compare MI Gas Website
U-17684:	DTE Electric Company	*Ex Parte* ROA Tariff Changes
U-17866:	Glacial Energy of Michigan and Glacial Natural Gas, Inc.	AES & AGS License Revocation

QUALIFICATIONS OF HEATHER A. CANTIN
CASE NUMBER U-18248
PART I

U-17882:	Consumers Energy	Rate Case (Gas Choice Tariff Changes)
U-17900:	Consumers Energy	Gas Choice Tariff Changes
U-18115:	Commission's own motion,	Implementation of PA 299 of 1972
U-18192:	DTE Electric Company	*Ex Parte* ROA Tariff Changes
U-18196:	Presque Isle Electric & Gas	Objection to 2016/2017 PUA
U-18239:	Consumers Energy	Implementation of PA 341 Section 6w

DIRECT TESTIMONY OF HEATHER A. CANTIN
CASE NUMBER U-18248
PART II

Q: What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to present the MPSC Staff (Staff) position and recommendation regarding the Retail Access Service Rider – EC2 (RASR) tariff language modifications presented by DTE Electric Company (DTE or Company) witness Timothy A. Bloch.

Q: Are you sponsoring any exhibits in this proceeding?

A: No.

Q: What specific RASR tariff modifications are Staff addressing?

A: My testimony addresses portions of the proposed RASR tariff modifications on pages nine and ten of Exhibit A-12, Schedule 2 sponsored by Company witness Bloch.

Q: What is the first RASR tariff modification that Staff is addressing?

A: The first RASR tariff modification Staff is addressing is DTE's proposal to obligate customers to take full service or utility capacity service for 30 years under Section E4.2.1 page 9 of Exhibit A-12, Schedule 2.

Q: Does Staff agree with this proposed tariff modification?

A: No. While Staff does not object to the proposed changes to Section E4.2.1, Staff does not agree with specific language related to the 30-year term for full or utility capacity service. The Company proposes the following language:

> Customers who so notify DTE Electric shall be obligated to take Full Service or Utility Capacity Service from DTE Electric for 30 years.

As discussed further in the testimony of Staff witness Eric Stocking, Staff does not agree with the Company's proposed 30-year term. Rather, Mr. Stocking explains that after the initial four year period, the statute only allows a single year term for the capacity charge. Because a 30-year term for the capacity charge would violate Act 341, the Commission should reject the Company's proposed language.

To conform to the law, Staff suggests replacing the proposed language with the following:

> Customers who so notify DTE Electric shall be obligated to take Full Service or Utility Capacity Service from DTE Electric for the initial four-year planning period beginning June 1, 2018 through May 31, 2022. Customers who so notify DTE Electric in any subsequent planning year after the initial four-year planning period, shall be obligated to take Full Service or Utility Capacity Service from DTE Electric for the applicable planning year.

Q: What is the second RASR tariff modification Staff is addressing?

A: The second RASR tariff modification Staff is addressing is the addition of Section E4.2.2 on pages nine and ten of Exhibit A-12, Schedule 2. The proposed section requires each Retail Access Customer to notify DTE that it will <u>not</u> be returning to full service or initiating utility capacity service beginning June 1, 2018 and to provide documentation from their AES that demonstrates that the AES has secured sufficient capacity to serve that customer's load from June 1, 2018 to May 31, 2022. This provision also obligates each Retail Access Customer who fails to provide notice to take Full Service or Utility Capacity Service from DTE for 30 years.

Q: Does Staff agree with this proposed RASR tariff addition?

A: No, Staff objects to the proposed tariff language in Section E4.2.2. Historically, DTE has not required its Retail Access Customers to take any action if they did not intend to return to full service. Staff does not see the logic for requiring Retail Access Customers to notify DTE that they will *not* be doing something, like taking utility capacity service. The Company has proposed new notice requirements in Section E4.2.1 of Exhibit A-12, Schedule 2 for Retail Access Customers that request to take full service or utility capacity service. Additionally, Staff takes issue with DTE's proposal to burden choice customers by requiring them to prove that their respective AES has sufficient capacity. Act 341 of 2016 sets out the requirements for making a capacity demonstration, and puts the onus for doing so directly on the AES. The Company should not be permitted to shift the burden from the AES, which is required to notify the Company if it will not be able to satisfy its capacity obligation, to place an even heavier burden on the AES customer. Furthermore, as discussed in the testimony of Staff witness Stocking, Staff does not agree with DTE's proposed 30-year term and so that provision in the proposed tariff should not be approved. For these reasons, Staff objects to the proposed language as written in Section E4.2.2.

Q: What is the third RASR tariff modification Staff is addressing?

A: The third RASR tariff modification Staff is addressing is DTE's proposal to establish a firm service queue and placing customers in that queue on an interruptible service tariff under Section E4.2.3 on page 10 of Exhibit A-12, Schedule 2.

Q: Does Staff agree with this proposed RASR tariff addition?

A: No. As addressed in the testimony of Staff witness Stocking, Staff does not agree with DTE's proposed requirement to place ROA customers returning to full service or utility capacity service onto an interruptible tariff. Therefore, Staff does not agree with the proposed language as written, and the Commission should reject it.

Q: Is Staff proposing any modifications to DTE's RASR tariff?

A: Yes.

Q: What RASR tariff modification is Staff proposing?

A: Staff is proposing a date change to Section E2.6 (Metering) on page 5 of Exhibit A-12, Schedule 2. Specifically, Staff proposes to change the date of September 29, 2009 to April 28, 2017. Staff's proposed modification is in line with the Commission's April 28, 2017 order from Case No. U-15801, which altered the electric choice procedures to comply with Act 341.

Q: Does this conclude your testimony?

A: Yes it does.

S T A T E OF M I C H I G A N

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**

QUALIFICATIONS AND DIRECT TESTIMONY OF

ERIC W. STOCKING

MICHIGAN PUBLIC SERVICE COMMISSION

July 21, 2017

QUALIFICATIONS OF ERIC W STOCKING
CASE NUMBER U-18248
PART I

Q. Please state your full name and business address for the record.

A. My name is Eric W. Stocking and my business address is 7109 West Saginaw Highway, Lansing, MI 48917.

Q. By whom are you employed?

A. I am employed by the Michigan Public Service Commission (MPSC or the Commission).

Q. In what capacity are you employed?

A. I am an Economic Specialist in the Resource Adequacy and Retail Choice Section, within the Financial Analysis and Audit Division.

Q. Would you please describe your educational background?

A. I received a degree of Bachelor of Science in Economics from Michigan State University in 2009.

Q. Would you please describe your professional experience?

A. In February 2010, I entered into employment as an Economic Analyst in the Generation and Certificate of Need Section in the Electric Reliability Division of the MPSC with a focus on generation resource adequacy, load forecasting, and integrated resource planning (IRP). In 2010, I assisted with the development of the Staff report in Case No. U-16077, in which Staff reviewed an electric generating alternatives analysis (EGAA) report for a proposed new coal-fired generation unit pursuant to the air permitting process under the Michigan Department of Environmental Quality (MDEQ). In 2012, I provided testimony and other technical analysis supporting Staff’s position in Indiana Michigan Power Company’s application for certificate of necessity. In 2013, I provided

QUALIFICATIONS OF ERIC W STOCKING
CASE NUMBER U-18248
PART I

Testimony and other technical analysis supporting Staff's position in Consumers Energy Company's application for certificate of necessity. Since 2014, I have been responsible for Staff's analysis, review and results of the Commission's annual capacity self-assessment, in which the Commission monitors the short and mid-term resource adequacy outlook for Michigan. I have also worked on several projects relating to long-term generator optimization planning, including the State of Michigan's analysis of the impact of the Clean Power Plan. I have attended several training sessions on the EGEAS capacity expansion model and performed numerous analyses of various issues relating to resource adequacy and impact analysis for internal Staff use. In the fall of 2016, I took on the role of Economic Specialist in the Resource Adequacy and Retail Choice Section of the Financial Analysis and Audit Division. In addition to my responsibilities pertaining to resource adequacy demonstrations and resource optimization analysis, I am currently involved in the implementation and casework associated with the State Reliability Mechanism (SRM) and the Integrated Resource Planning (IRP) processes.

Q. Have you previously presented testimony before this Commission?

A. Yes. I have provided testimony in the following cases before the Commission:

U-17026 – Indiana Michigan Power Company Certificate of Necessity Case

U-17087 – Consumers Energy General Rate Case

U-17429 – Consumers Energy Certificate of Necessity Case

U-18250 – Consumers Energy Securitization Case

U-18239 – Consumers Energy State Reliability Mechanism Case

DIRECT TESTIMONY OF ERIC W STOCKING
CASE NUMBER U-18248
PART II

Q. What is the purpose of your testimony?

A. The purpose of my testimony in this case is to present Staff's position on the following matters: (1) the appropriate term of the State Reliability Mechanism (SRM); (2) the application of the capacity charge term to potential Retail Open Access (ROA) customers returning to utility capacity service; (3) the Company's plans to serve any potential returning capacity obligations; and (4) certain provisions contained in Section E4.2.2 of Company Exhibit A-12, Schedule 2.

Q. Are you sponsoring any exhibits?

A. No.

(1) Term of the State Reliability Mechanism

Q. Can you explain the difference between the SRM term and the capacity-charge term?

A. The SRM term specifies how long the State Reliability Mechanism will be in place. It is characterized in Section 6w(2) of Public Act 341 of 2016 (Act 341) as a minimum of four consecutive planning years beginning in the upcoming planning year. The capacity charge term governs how long applicable load is subject to the capacity charge, even if the Alternative Electric Supplier (AES) is able to make a satisfactory demonstration that it has owned or contracted resources that are sufficient to meet its capacity obligation in the future.

Q. What is Staff's position regarding the length of the SRM term?

A. If Act 341 remains unchanged, Staff contends that the SRM should be effective in perpetuity.

Q. Why should the SRM be in place indefinitely?

A. The SRM provides the Commission a mechanism to ensure the long-term reliability of the electric grid in Michigan. The application of the SRM over a long time horizon provides additional visibility into the overall resource adequacy outlook for Michigan, and provides an additional economic incentive to Load Serving Entities (LSEs) to diligently plan for future capacity resource obligations.

(2) Application of the Capacity Charge Term

Q. How does Staff's opinion differ from DTE Electric Company's (the Company or DTE) regarding the application of the capacity-charge term?

A. On page 15, line 20 through page 16, line 20 of his direct testimony, Company witness Don M. Stanczak asserts that any AES retail electric load that returns to bundled service, or takes capacity service from the Company under the SRM at any point in time due to an inability of the AES serving that load to make a satisfactory capacity demonstration, then that AES load would be subject to the capacity charge established in this case for a term of 30 years. Staff contends that the portion of the Company's approach in which AES load that is taking capacity service from the Company pursuant to the rules of the SRM, is in direct conflict with statutory language. P.A. 341, section 6w (6), states:

> 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.

Q. Please explain how the Company's application of the 30-year capacity charge term conflicts with the statutory language identified previously.

DIRECT TESTIMONY OF ERIC W STOCKING
CASE NUMBER U-18248
PART II

A. The Company is claiming that if any portion of AES load pays the capacity charge established in this proceeding and receives capacity service from the Company for even one year, then that portion of AES load would be subject to the capacity charge for 30 years. If, in its capacity showing for a subsequent year, the AES is able to make a satisfactory capacity demonstration, DTE posits that the load that had previously been subject to the capacity charge would continue to pay the charge until the end of the 30-year term. Only after the 30-year term would that portion of AES load have the opportunity to relieve itself of its commitment to pay the capacity charge to the Company. The statute clearly states that a capacity charge shall not be assessed for an AES that can demonstrate that it can meet its capacity obligations for each planning year. A 30-year capacity charge cannot be justified when an AES meets its capacity demonstrations in future years.

Q. What is the Staff's recommendation regarding the application of the capacity-charge term?

A. Staff recommends that the Commission interpret the statutory language cited above to mandate that a capacity charge may only be assessed onto AES load for years in which the AES is unable to provide a satisfactory capacity showing before the Commission. For any years in which the AES is able to demonstrate that it has owned or contracted resources that satisfy its capacity obligations, no capacity charge should be levied onto that particular AES's customers.

Q. Is there anything different about the initial capacity demonstration within the SRM that would conflict with Staff's position on the term of the capacity charge?

A. Yes. PA 341 Sec. 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 any of the 3 subsequent planning years, the capacity charge is applicable for each of those planning years.

Based on this statutory language, Staff contends that in the initial four-year demonstration, any portion of AES load that cannot make a satisfactory capacity demonstration would be subject to a capacity charge term of four years. If, in a subsequent capacity demonstration, the AES is able to demonstrate that it has owned or contracted resources to meet its capacity obligations, then its customers would no longer be subject to the capacity charge determined in this proceeding.

Q. What is the Staff's recommendation regarding application of the capacity-charge term?

A. Staff recommends that the Commission interpret the statutory language above to mean that in the initial four-year capacity demonstration for planning years 2018/19, 2019/20, 2020/21, and 2021/22 the term of the capacity charge should be set at 4 years. In subsequent capacity demonstrations (planning years 2022/23, 2023/24, etc.) that the term of the capacity charge be set to 1 year.

(3) DTE's Plan to Serve Returning AES Load

Q. How does the Company plan to serve AES load that returns to full service in the near term?

A. On page 12 of her direct testimony, Company witness Angela P. Wojtowicz states that due to the short amount of time that DTE will have to acquire any additional capacity resources to serve returning AES load in the planning year beginning

June 1, 2018, and potentially one or more subsequent planning years, the Company plans to purchase Zonal Resource Credits (ZRCs) to serve that load in the Midcontinent Independent System Operator (MISO) Planning Resource Auction (PRA). In the future, once the Company knows how much returning AES load it will be required to provide capacity to, it will pursue the most feasible option available for each given year.

Q. Would the Company's plans to serve potential returning AES load in the near term through ZRC purchases in the PRA be at all different than the plans that would have been used by the AES should that load have remained with the AES for the near term?

A. No, not likely for the near term.

Q. Does the Company discuss any other strategies to serve AES load that is either returning to bundled service, or taking capacity service from the Company in the near term?

A. Yes. As discussed by Company witnesses Stanczak and Wojtowicz, in the event that there exists a shortfall of physical capacity within the entire MISO footprint during any of the years in which the Company plans to serve ROA load with ZRC purchases from the auction, that it would place all returning ROA customers that do not have a commitment of firm, physical capacity on to an interruptible tariff; and those customers would be subject to a discounted capacity charge consistent with the Company's current interruptible customers.

Q. Does Staff agree with the Company's proposal to place customers returning to utility capacity service onto an interruptible tariff, in the event that the MISO footprint experiences a shortfall such that DTE is unable to procure ZRCs to satisfy its capacity obligations?

A. Staff is generally supportive of any LSE utilizing demand response resources as a means to satisfy its capacity obligations. However, Staff contends that a customer being provided interruptible capacity service at a discounted capacity charge should be voluntary—not a requirement of returning to utility service—either bundled or capacity only.

Q. Is it possible for a customer to enter into an interruptible service contract with its AES provider rather than being placed onto an interruptible tariff upon returning to utility service?

A. It is Staff's understanding that an AES, as a registered LSE within MISO, does have the ability to enter into a demand response contract with its customers to help fulfill its capacity obligations as specified by the MISO tariff. In this case, the demand response resource would be subject to the same verification and non-performance penalties as outlined by Company witness Wojtowicz on page 13 of her direct testimony.

Q. Does the MISO footprint have a significant risk of being short of firm capacity resources to satisfy capacity obligations in the near term?

A. No. As outlined on page 4 of the 2017 OMS MISO Resource Adequacy Survey,[1] the MISO region is projected to exceed its 1 day in 10 reserve margin of 15.8% for the next 5 years, when considering only firm and committed capacity

[1] https://www.eenews.net/assets/2017/06/16/document_ew_02.pdf

resources. When potential new capacity resources are considered, the regional reliability outlook is strengthened even further.

Q. All else being equal, does the possibility of existing customers returning to utility capacity service, either as bundled or capacity-only customers, have any effect on the overall level of reliability of the MISO footprint?

A. No. Any load that may return to utility capacity service as early as June 1, 2018 is load that has previously existed and been provided capacity via the MISO resource adequacy construct. It would not constitute any incremental load that would be detrimental to the ability of the region to meet its reliability requirements.

Q. Based on the projections included in the 2017 OMS MISO Survey, does Staff believe it is likely that the Company will be unable to procure an adequate amount of incremental ZRCs in the auction to satisfy its capacity obligations?

A. No.

Q. All else being equal, does the possibility of existing customers returning to utility capacity service, either as bundled or capacity-only customers, have any effect on the ability of MISO Zone 7 to meet its local clearing requirement (LCR)?

Q. No. As previously stated, any AES load that returns to utility capacity service does not constitute any new or incremental load, nor does it have any effect on the amount of resources that are available within Zone 7 and used to meet its LCR in the near term.

(4) Capacity Demonstration language in Company Exhibit A-12, Schedule 2.

DIRECT TESTIMONY OF ERIC W STOCKING
CASE NUMBER U-18248
PART II

Q. Are there any elements of Company Exhibit A-12, Schedule 2 that Staff takes issue with?

A. Yes, in Section 4.2.2, beginning on page 9 of Company Exhibit A-12, Schedule 2, the Company has included language that proposes instituting a requirement on the AES to demonstrate to the Company that it has secured sufficient capacity to serve its customer's load from June 1, 2018 through May 31, 2022. Staff asserts that the guidelines and requirements by which capacity demonstrations relating to the SRM will be filed and reviewed by the Commission are currently being established in a series of technical workgroup meetings in Case No. U-18197, pursuant to Commission Order. Therefore, any discussion of capacity demonstration requirements in this matter should be considered inappropriate and not approved in this matter.

Q. Does this conclude your direct testimony in this matter?

A. Yes, it does.

MS. DONOFRIO: Staff calls to the stand Nicholas M. Revere.

- - -

N I C H O L A S M. R E V E R E

was called as a witness on behalf of Michigan Public Service Commission Staff and, having been duly sworn to testify the truth, was examined and testified as follows:

DIRECT EXAMINATION

BY MS. DONOFRIO:

Q Please state your name for the record.

A My name is Nicholas M. Revere.

Q Please provide your business address.

A I'm referring to the prefiled direct testimony, I have a physical copy in front of me. 7109 West Saginaw Highway, Lansing, Michigan 48917.

Q And by whom are you employed?

A The Michigan Public Service Commission.

Q And did you cause to be filed on July 21 a document entitled Qualifications and Direct Testimony of Nicholas M. Revere, consisting of a cover page and 14 pages of questions and answers?

A I did.

Q And if I were to ask you those same questions today, would your answers be the same?

A Yes, they would.

Q And you don't have any corrections to that testimony?
A I don't believe so, no.
Q And you sponsored Exhibits S-1.1, S-1.2, S-1.3, each of those single-page documents, S-1.4, which is a three-page document, and S-1.5, which is a 42-page document. Were those exhibits created by you or at your direction?
A They were.
Q Do you have any changes to those exhibits?
A I do not.
Q Mr. Revere, did you receive discovery requests from the Company in this matter?

MR. MIDDLETON: Your Honor, before we create a record on this, I would ask that we have the discussion about whether or not it's appropriate to even proceed beyond this point. If it is, then of course we can make the record, and if it's not, then this is unnecessary from this point forward with this witness.

JUDGE EYSTER: Is that an objection?

MR. MIDDLETON: I'm asking whether or not we can have the argument on whether or not to even go any further with this direct examination since it's the matter that we have a disagreement about, whether it's proper, and I'd prefer not any record to be made of it if you agree that it's not proper rather than have a record made and have it stricken from the record. That's what

I'm asking. And if you're O.K. with that, we'll proceed that way, if not, then I'll raise my objection at the end of it.

JUDGE EYSTER: Well, I'll take that as an objection to the question that was just asked, then.

MR. MIDDLETON: O.K.

JUDGE EYSTER: So state your position.

MR. MIDDLETON: O.K. Thank you, your Honor. As I understand it, where Staff wishes to proceed now is to take discovery that the Company served on Staff and through this witness enter responses into the record as additional exhibits to Staff's case. That's clearly supplemental direct. There's no supplemental direct opportunity in this proceeding, none was set at the beginning of the case, everyone has agreed to the case schedule, no one agreed that they could have supplemental direct and another opportunity to augment their direct case in this proceeding. All this is is, after reviewing rebuttal from the other parties, which was done properly in accordance with the case schedule, an attempt by Staff to augment the record. It's not appropriate. You don't get to introduce your own responses to another party's discovery later on in the case. And it's not an appropriate remedy, in my opinion, if Staff in turn argues that, well, I have the witness here present so you can cross-examine him on this. It's got nothing to do with the content of these answers, it has everything to do with proper procedure.

So if we're going to allow this kind of an opportunity for supplemental direct, then everybody in this room should have been afforded an opportunity to do supplemental direct. And that's the nature of our disagreement on this. We just think this is improper procedure. Their case is the one they made in direct, they don't get to augment it now, and they shouldn't be allowed to augment it, whether it's through cross-examination in answers from this witness or through their responses to our discovery.

JUDGE EYSTER: Ms. Donofrio.

MS. DONOFRIO: We are seeking to have admitted five responses from this witness to questions that he was asked by the Company. These aren't questions that Staff drafted themselves, these are questions that the Company asked of the witness. The Company asked these questions after reviewing Mr. Revere's initial -- his direct testimony, not after his rebuttal. Mr. Revere did not file rebuttal testimony. These responses were made on August 14.

And it's nothing new for a party to want to submit its own discovery responses. For example, in the recent July 31 order of the Commission in Case No. U-18124, the Commission makes reference to, in that case, Consumers Energy who filed and made exhibits its responses to Staff's audit questions, for example.

These are not responses that Staff could have made as part of its direct testimony in this matter because the questions were not asked until after direct testimony was filed. So if it even did constitute testimony, it could proper -- it would only be in the form of rebuttal as opposed to direct, because these are questions that were posed by the Company to the Staff following direct testimony, they are not supplemental direct testimony.

In addition --

JUDGE EYSTER: Well, just a minute. You just started asking this witness additional questions.

MS. DONOFRIO: I was just going to lay a foundation for the documents, so that it was to authenticate the document.

JUDGE EYSTER: O.K. But generally when we have our hearings, we've got all our prefiled testimony, and the direct testimony has been filed.

MS. DONOFRIO: Correct.

JUDGE EYSTER: It's bound into the record and we move to cross.

MS. DONOFRIO: Correct.

JUDGE EYSTER: And so it's your intent to continue with the direct?

MS. DONOFRIO: In order to lay a foundation for a document, correct. And --

JUDGE EYSTER: Well --

MS. DONOFRIO: -- our rules provide --

JUDGE EYSTER: -- can we agree that this would be considered hearsay?

MS. DONOFRIO: No, I would not, because --

JUDGE EYSTER: Why not?

MS. DONOFRIO: Because the witness is here and subject to cross-examination.

JUDGE EYSTER: Well, I didn't bring my rules, but it is an out-of-court statement used for the purpose of the truthfulness asserted.

MS. DONOFRIO: In the alternative --

JUDGE EYSTER: And I know that that's one of the exceptions to the hearsay rule, but --

MS. DONOFRIO: In addition, the witness is here. I mean technically all of our testimony is hearsay because it is an out-of-court statement of the witness, but we bind it in. This is an administrative hearing, and our rules provide that the Rules of Evidence are only applicable to the extent practicable; and in this, in administrative hearings, there are a lot of things that we do slightly differently because it is not practicable to directly follow those issues, those rules to the T because these are not the same kinds of civil and criminal litigation that those Rules of Evidence were created to deal with.

But the witness is here to authenticate the documentary response that was filed in this case. In addition, Rule 792.10430, or our Rule 430, evidence testimony in written form, provides that any testimony that is -- that we wanted to admit, so long as it is proper, and can be bound into the record so long as it's provided to the other parties seven days before the hearing. And certainly these responses --

JUDGE EYSTER: What are you reading? Excuse me.

MS. DONOFRIO: Rule -- it's Rule 430, R792.10430 of the Commission's Administrative Hearing Rules.

JUDGE EYSTER: O.K. What's it state?

MS. DONOFRIO: Rule 430.

JUDGE EYSTER: You know, hang on a second. We're going to go off the record for a little while. I'm going to go get my Court Rules and the

Commission's Rules. It wasn't clear, I know that you did make mention in that e-mail that there was going to be a motion to admit this, but I didn't understand from that that we had a contested motion that I was going to have to address.

MR. MIDDLETON: I understand, your Honor.

JUDGE EYSTER: So I'm going to go grab that material so I can take a look at it.

MS. DONOFRIO: If you want, you can have mine.

JUDGE EYSTER: I'll go grab mine.

(At 9:36 a.m., there was a brief pause in the proceedings.)

JUDGE EYSTER: O.K. We're back on the record. Ms. Donofrio.

MS. DONOFRIO: Yes. With regard to Rule 430, we do not agree that this is supplemental direct testimony, however, if it were, this rule provides that the testimony has to be served on the other parties seven days prior to the hearing or, if the presiding officer agrees, not less than 24 hours, so that the other parties have at least 24 hours to examine the testimony. But these discovery responses have been in the possession of the parties since August 14, and we provided a week ago our intention to have these admitted as exhibits, and as

I had indicated, all of the other -- all the intervening parties have agreed to entry of these exhibits.

In addition, Rule 430(2) provides that the presiding officer may authorize any witness to present oral direct testimony. So we do not think that this is improper.

The goal of these hearings is to provide a record for the Commission. The Company raised through its discovery some questions that it did not feel were answered by Mr. Revere's testimony, and he provided responses, and we think that the material in these discovery responses is relevant. In fact, we think there can be no question that -- no question as to relevancy. And the witness is here to authenticate the document personally and to respond, and he is here for and available should any party wish to cross-examine him with regard to the content of these discovery responses.

Discovery responses are the type of exhibit that is routinely entered into in these cases. For example, in lieu of taking the cross-examination of Mr. Stanczak, we asked some discovery questions of Mr. Stanczak and the Company has stipulated that we can enter those in response. Discovery questions are certainly something that is part of this process, and it is routinely relied upon by the Commission. And as I said, in the recent case, this is the July 31 order, at page 19 of the Commission's order in U-18124, the Commission relied on exhibits of Consumers Energy that were Consumers Energy's own witness's responses to Staff audit questions. So this is not something that has never happened before. This is nothing new. And this witness could not have provided these exhibits as part of his direct testimony because the questions were not posed to him until after direct testimony was filed.

JUDGE EYSTER: Mr. Middleton.

MR. MIDDLETON: Very briefly, your Honor. He responded to these on August 14 due to a time out of the office that Mr. Revere was on vacation, as I understand it. These were, response from Staff were provided past the due date we set at the original case schedule. But Staff had these in their possession since the beginning of August, so at least two weeks before he actually filed -- excuse me -- served us with his responses, and roughly a month before we're sitting here today having a hearing.

He had an opportunity to file additional information in rebuttal. We all understand as attorneys that practice in this venue that people need, sometimes need to be creative about what they consider rebuttal and what they don't; they had that opportunity, he didn't.

He had the opportunity in direct, he didn't.

And Rule 430 really isn't a correct application whatsoever here. I mean obviously if the interpretation of that rule is anybody can file direct as long as it's seven days before the hearing, well, then why would we set a case schedule, why would all the parties in this room agree that this is the due date for direct, this is the due date for rebuttal; it would be meaningless, we would just sit around and file whenever we felt like it supplemental direct as long as it came in seven days before the hearing.

JUDGE EYSTER: Mr. Middleton, that sentence starts with unless otherwise ordered by the presiding officer, which was offered, so the seven days doesn't apply here.

MR. MIDDLETON: Yeah, I'm just responding to the --

MS. DONOFRIO: And --

MR. MIDDLETON: -- characterization from Staff. If I might continue.

JUDGE EYSTER: Yeah.

MR. MIDDLETON: I don't know how the audit got in in the Consumers case, I have no idea --

JUDGE EYSTER: I don't either.

MR. MIDDLETON: -- and I don't know if

that was agreement of the parties; and certainly I have practiced here long enough to understand that there are all sorts of agreements that happen between parties all sorts of times for a whole variety of reasons. None of those, whatever they might be, are present today with respect to our opinion on whether or not this is appropriate to enter this into the record. It's clearly supplemental direct, it's incremental testimony; it is not a correction, it is not anything like that whatsoever.

And, of course, our responses to Staff are totally different. If Staff wants to enter those as opposed to cross-examining my witness, that's fine with us, they can ask the same questions of my witness if, you know, they're required to be present at the hearing.

This is completely different. This is Mr. Revere's own words that Staff wants to do direct examination on him and then add that to the record and make this as if it were part of his direct testimony, which it was not. That's clearly supplemental direct; I don't know why they say it's not, because it clearly is. Didn't meet the deadline, incremental testimony, not presented in any way, shape, or form prior to this very moment in this proceeding. We think that's inappropriate. We think it sets a really bad precedent for how you go about conducting the cases, there's no certainty as to due dates, and we don't believe it should be allowed.

MS. DONOFRIO: If I might respond. We were not indicating by talking about the seven days that any time someone wants to submit revised direct -- or supplemental direct, that it just has to be filed seven days before, we were just making a point that the parties had notice and the opportunity to review these materials more than seven days prior to the hearing. So there's no surprise here and there's no lack of a party's -- I mean there's just no surprise, and all parties have had an opportunity to review these materials. That is the only point that we were making with regard to that part of Rule 730 [sic].

However, Rule 730 [sic] also provides that the administrative law Judge may allow oral direct testimony as well. And if -- the only reason we were going to provide any direct testimony was just to lay a foundation for the document. If the parties -- if you agree that it is proper, or in this case allowable, for these particular discovery responses to be made exhibits, I don't know if the Company will agree that they are at least authentic and that we don't need to lay that particular foundation. If they would agree to that, then we don't need this witness to provide any direct, supplemental direct testimony at all, we would merely submit these exhibits along with his other exhibits in this matter.

And to close, we believe that the information in these discovery responses will be helpful to the Commission in understanding the matters before it so that they can make a full and informed decision in this matter.

JUDGE EYSTER: Mr. Middleton, anything else?

MR. MIDDLETON: No, your Honor.

JUDGE EYSTER: I think I've been doing these cases with the Public Service Commission for something in the range of 15 years, and I'll have to say this is the first time that this has arisen, and I'm not prepared to go down that road of having people walk in on the day of hearing and say we'd like to submit all these documents in our case-in-chief. That kind of opens up the door to chaos. We set our deadlines. If there's an appropriate motion, as Mr. Middleton indicated, some potential ways to craft prefiled testimony that would get this information in, I'm sure there are other ways, but I'm not going to permit this kind of thing on the day that we walk in for a hearing. So and I'm not sure it's even proper from an evidentiary rules standpoint. And I'm not going to just have people calling in witnesses and having them testify the day of.

So you've got your record, the Commission is going to read the record, you can file a motion with them, so they'll ultimately be the ones to decide whether or not to consider the information, but I'm not going to open that door, it's not something I'm prepared to do.

MS. DONOFRIO: O.K. With that, we do have one other exhibit that, hearing room exhibit that the parties have stipulated to.

JUDGE EYSTER: O.K.

MS. DONOFRIO: The only problem is that we labeled it Exhibit S-7, so we either need to relabel it as Exhibit S-2 or have a gap. Do you want to go off the record for a minute just to discuss that with the court reporter?

JUDGE EYSTER: We can go off the record. We're off the record.

(A brief discussion was held off the record.)

JUDGE EYSTER: O.K. We're back on the record.

MS. DONOFRIO: So we do have one additional exhibit, which is Exhibit S-7, which is the discovery responses of Mr. Stanczak, and to my understanding, all of the parties have stipulated to entry of that hearing room exhibit.

JUDGE EYSTER: Are there any objections to the admission of Exhibit S-7?

O.K. Hearing none, it's admitted.

MS. DONOFRIO: And with that, Staff moves to bind in the direct testimony and Exhibits S-1, S-2, S-3, S-4 -- I'm sorry -- S-1.1, S-1.2, S-1.3, S-1.4, and S-1.5, of Mr. Revere, have those bound into the record and the exhibits admitted.

JUDGE EYSTER: Those are the prefiled exhibits?

MS. DONOFRIO: Those are the prefiled exhibits, as well as his 14 pages of qualifications and testimony.

JUDGE EYSTER: Any objection?

O.K. The testimony is bound in. And it's just one exhibit. Or is it multiple exhibits?

MS. DONOFRIO: Well, it was presented as Exhibits S-1.1 through S-1.5, I don't know if it was marked by the court reporter as just one Exhibit S-1 or if it was five separate.

JUDGE EYSTER: The exhibits are admitted.

(Testimony bound in.)

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S T A T E   O F   M I C H I G A N

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

QUALIFICATIONS AND DIRECT TESTIMONY OF

NICHOLAS M. REVERE

MICHIGAN PUBLIC SERVICE COMMISSION

July 21, 2017

QUALIFICATIONS OF NICHOLAS M. REVERE
CASE NUMBER U-18248
PART I

Q. Please state your name and business address.

A. My name is Nicholas M. Revere. My business address is 7109 West Saginaw Hwy, Lansing, Michigan 48917.

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

A. I am employed by the Michigan Public Service Commission (MPSC or Commission) as the Manager of the Rates and Tariff Section of the Regulated Energy Division.

Q. Would you briefly describe your academic background?

A. I received a Bachelor of Arts degree in Political Science and a Bachelor of Arts degree in Economics from Michigan State University in 2006. In August of 2008 and 2009, I completed the annual National Association of Regulatory Utility Commissioners (NARUC) regulatory studies program at Michigan State University, which included courses on ratemaking, rate case auditing, regulatory policy, and other regulatory issues. In September of 2010, I completed the Institute for Public Utilities Advanced Regulatory Studies Program. In October 2012, I completed the Association of Edison Illuminating Companies' Advanced Course in Load Research.

Q. What are your current responsibilities at the MPSC?

A. As Manager of the Rates and Tariff Section, I supervise the members of and oversee the responsibilities of the section. The responsibilities of the section include, but are not limited to, analyzing utility reports, financial records, and rate case filings to determine the appropriate level of rates for regulated energy utilities, utilizing laws, regulations, and Commission policies. The section is charged with conducting MPSC Staff (Staff) Cost of Service allocation studies (COSS) and rate designs for gas and electric utilities and reviewing special contracts, gas storage rates, and Act 9 intrastate pipeline rates. The section is also involved in customer complaint and inquiry processing, updating electric and gas comparison spreadsheets for the MPSC website, and tariff administration.

Q. Have you previously filed testimony in any cases before the Commission?

A. Yes. I filed testimony in the following cases:

Case	Company	Case Type
U-15645	Consumers Energy Electric	Rate Case
U-15766	MichCon Gathering v. Highmount	Act 9 Complaint
U-15768	Detroit Edison/DTE Electric	Rate Case
U-15985	MichCon/DTE Gas	Rate Case
U-15986	Consumers Energy Gas	Rate Case
U-16169	SEMCO Gas	Rate Case
U-16191	Consumers Energy Electric	Rate Case
U-16566	Consumers Energy Electric	RDM Recon
U-16568	Upper Peninsula Power Company	RDM Recon
U-16780	Detroit Edison/DTE Electric	RDM Recon
U-16830	Wisconsin Electric Power Company	Rate Case
U-16952	Detroit Edison/DTE Electric	ECIM Recon
U-16999	MichCon/DTE Gas	Rate Case
U-17643	Consumers Energy Gas	Rate Case
U-17688	Consumers Energy Electric	Act 169
U-17689	Detroit Edison/DTE Electric	Act 169
U-17701	MichCon/ DTE Gas	IRM
U-17735	Consumers Energy Electric	Rate Case

QUALIFICATIONS OF NICHOLAS M. REVERE
CASE NUMBER U-18248
PART I

U-17767	Detroit Edison/DTE Electric	Rate Case
U-17882	Consumers Energy Gas	Rate Case
U-17990	Consumers Energy Electric	Rate Case
U-18014	Detroit Edison/DTE Electric	Rate Case
U-18124	Consumers Energy Gas	Rate Case
U-18250	Consumers Energy Electric	Securitization
U-18224	Upper Michigan Energy Corporation	CON
U-18239	Consumers Energy Electric	SRM

Q. What is the purpose of your testimony in this case?

A. The purpose of my testimony in this case is to present Staff's position on the calculation of the capacity charge for DTE Electric (the Company), including the appropriate costs to be included and how the charge should be levied.

Q. Are you sponsoring any exhibits in this case?

A. Yes, I am sponsoring the following exhibits:

Exhibit S-1.1, STAFF Projected 2017 Capacity-Related Generation Cost

Exhibit S-1.2, STAFF Projected 2017 PA295 Capacity-Related Generation Cost

Exhibit S-1.3, STAFF Projected 2017 Capacity-Related Generation Cost & Energy Sales Revenue Net of Fuel Cost

Exhibit S-1.4, STAFF Summary of Present and Proposed Revenue by Rate Schedule

Exhibit S-1.5, Staff Proposed Rate Design

Q. What costs are properly included as part of the capacity charge?

A. 2016 PA 341 Section 6w(3) lays out which costs should be included, and offsets thereto, as follows:

> 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 costs should be considered capacity-related for the purpose of calculating the capacity charge per 2016 PA 341 Section 6w(3)?

A. Costs incurred to supply capacity should be included as capacity-related costs. In Staff's opinion, the proper cost of capacity is the Cost of New Entry (CONE), or the cost to build a combustion turbine (CT). The characteristics of a CT are such that it effectively supplies only capacity. A CT is relatively expensive to run to produce energy, but relatively inexpensive to build. Therefore, it is only economically utilized to supply energy in those hours when load is at its highest. These hours are also those which are considered to set the capacity need of the utility to serve its customers. Plants other than CTs are more expensive to build and less expensive to run, making them the most cost-effective choice only if they run enough hours a year so that the total cost is lower. Therefore, the difference between the cost to build a CT and any other type of plant is the capital cost expended to produce lower energy costs. In Staff's opinion, this cost should properly be considered an energy cost. However, the law requires that net sales to the market be applied as an offset to the capacity-related costs. As all energy is bid into the market at the cost to run a plant, but plants are paid if dispatched at the highest bid called in the supply stack, these net-energy market sales (imperfectly) capture what Staff would consider to be the energy related portion of capacity costs. Therefore, to remove all costs above a CT and then apply an offset which effectively, if imperfectly, does the same, would be double counting the offset. An alternative is discussed below.

Q. Has the Company properly identified capacity-related costs currently included in base rates in its filing?

A. No. For the most part, the Company identifies certain energy-related costs, and considers all other costs capacity-related. They are not, however. Not all costs that are not energy-related are capacity-related. Thus, the Company identifies some costs as capacity-related that are not. These costs, which are not specifically energy-related, would more properly be considered non-energy costs.

Q. Has the Company properly identified capacity-related costs currently included in the PSCR process in its filing?

A. No. The Company assumes the entirety of the cost of renewables are capacity-related, as they effectively have zero energy cost. This assumption is incorrect and unreasonable. Renewables provide very limited capacity compared to their nameplate. Though the variable costs may be zero, the cost of the plants was incurred, in the main, to provide energy rather than capacity. Therefore, it is unreasonable to include these costs as entirely capacity costs. A reasonable method of determining the capacity-related cost of these plants is to multiply the generation by the capacity portion of the transfer charge applicable to each. Staff has done so on Exhibit S-1.2. Another reasonable method would be to multiply the nameplate capacity by the determination of effective load carrying capability determined by MISO (which is the effective percentage of the nameplate rating that can be used to supply capacity in MISO), and then multiply that number by the cost of capacity as determined by the Commission. As discussed later, the Commission is determining the cost of capacity in the Company's PURPA case; to maintain consistency, it would be reasonable to use this number. In addition, the Company utilizes the fixed payments under PURPA contracts to determine the capacity cost of those contracts. To maintain consistency, the Commission should use the value of capacity determined in the PURPA case to determine the cost of capacity associated with those contracts, when available. .

Q. How has Staff identified capacity-related costs included in base rates?

A. Staff went through the costs in the Cost of Service Study (COSS) and identified those that are capacity-related. All other costs are considered non-capacity. Staff's identification of capacity-related costs meets the requirements of 2016 PA 341 Section 6w(3), while the Company's does not, for the reasons laid out above. The results of Staff's capacity-related cost identification are shown on Exhibit S-1.1.

Q. What costs has Staff identified as capacity-related?

A. Staff identified costs currently allocated using the production cost allocator and other capacity-related costs. The current production cost allocator of 4CP (four coincident peak) 75-25 effectively recognizes that 75% of costs so allocated are capacity-related. Therefore, Staff split the costs into capacity- and non-capacity-related portions, using the 75-25 split. The 75% portion identified as capacity-related is then added to the determination of PURPA, 295, and net market revenues and allocated on the 4CP portion of the former combined allocator to identify the capacity-related revenue requirement by COSS class. The results of this calculation are shown on Exhibit S-1.3. An alternative methodology, as mentioned previously, is to identify all costs allocated by the former allocator, and set the percentage applied to determine which of those costs are capacity-related at the percentage necessary to make the resulting amount equal to CONE or some other measure of the value of capacity, as determined by the Commission. This would treat all costs in excess of CONE (or the Commission's chosen value of capacity) as non-capacity-related costs. Should the Commission determine such a method is more appropriate, Staff recommends that the levelized per year cost of a CT resulting from the Company's PURPA case, U-18091, be utilized. This would provide consistency in the Commission's determination of the value of capacity.

Q. Does Staff agree with the Company's calculation of net revenue from the four categories of revenue identified in Section 6w(3)(b) of 2016 PA 341?

A. For the most part. The only issue Staff takes with the calculation is the inclusion of administrative costs. The law expressly states that the revenues shall be netted against fuel costs, and does not mention administrative costs. Therefore, the Commission should not allow these expenses to be netted against this revenue. The result of removing these expenses is shown on Exhibit S-1.3.

Q. What is the most appropriate way to distribute the capacity-related costs to the various classes and schedules for recovery?

A. Ideally, these costs would be distributed to the classes according to the results of the COSS described previously. This results in cost-responsibility reflective of that currently in place. There is a reference in the law to a "single capacity charge as determined for each territory." The Company has interpreted this to mean a single capacity charge between similarly situated Retail Open Access (ROA) and full-service customers, allowing for collection of class cost responsibility from that class. Staff agrees with this interpretation. However, the wording of the law could be interpreted to require a single charge be paid by all customers, regardless of class or schedule, or the amount that is allocated under approved methods. If the Commission interprets the statute to mean that a single identical charge is required to be paid by all customers of a utility, the issue then becomes how best to design that charge to align the collection of costs with individual customers' contributions to the Company's capacity needs.

Q. How can the collection of costs be best aligned with customers' contributions to the Company's capacity needs?

A. To answer this, it is useful to distinguish between how members of different classes contribute to the Company's capacity needs. As costs are distributed by class, the cost responsibility is determined by the class' contribution, rather than the individual customers' contribution, to the measure of capacity. In a theoretical class consisting of only one customer, the approaches are the same. In a theoretical perfectly homogeneous class of any number of customers, all of whom use energy in exactly the same way, the approaches are also the same. However, two difficulties arise, even in such perfect cases. First, billing on the measure of contribution to capacity is effectively impossible, or at the very least not desirable. For the purpose of allocating cost, each class is allocated costs on the basis of 75% demand during the highest load hours of the four summer months, and 25% on total energy. These measures are averaged over a number of years. If costs are allocated on the basis of class contributions to these measures, how would a utility bill its customers? One could measure the contribution to the 4CP in the billing year, but this would not accurately correspond to how the costs were allocated, on that three-year average of the same measure.

Q. Are there any other concerns with such a method?

A. Yes. Customers would have a very difficult time determining when those hours would occur, as they are not known until after the fact. Indeed, if customers somehow knew when those hours would be, and also knew they were going to be charged based on those hours, customers would lower usage in those hours, making them no longer the highest hours. There is also an issue of randomness inherent in a particular customer's contribution to any given hour. A customer who, in all other hours surrounding the 4 CP hours (all potential CPs themselves, depending mostly on the vagaries of the weather), could theoretically contribute little to those particular hours. The customer could be away from home, and have their thermostat set such that the air conditioner (AC) does not run. Did that customer truly contribute less to the need for capacity, even if in the previous year their AC was running during each of the 4 CPs, had an electric dryer running, etc.? I think not. When costs are distributed to a large class of customers, these stochastic differences essentially even out, making the cost responsibility of the class as a whole appropriate. However, in that same class, attempting to charge on the same basis as the allocation makes little sense. So we are left, then, with imperfect proxies for capacity contribution on which the Company could bill its customers.

Q. What potential measures could be used for such a proxy?

A. One method that has been in use for some time, particularly for larger customers, is on-peak demand. This applies a charge to the highest hour (or some other finite period of time) of demand the customer places on the system during the on-peak hours of a billing month. This, in effect, recognizes that each of those on-peak hours has some chance of being the CP, and charges on that basis. For smaller classes, this measure is still problematic. A person who works odd shifts, for example, may be using some high-load device during portions of the on-peak time period that are less likely to become a CP, and therefore representative of capacity need, while not using that same device during the hours more likely to be a CP. This individual customer cannot sway enough load to move the actual CP, but is effectively paying as if they could. Another method that can be used to bill is isolating some number of hours likely to become the CP and charging each of those hours at the same rate. The previous example customer, then, would pay less than a customer who contributes that same load across all of those hours, effectively recognizing the reduced likelihood of contributing to peak. The challenge, then, becomes what period of hours to choose. Spreading a certain amount of cost over a smaller number of hours results in a rate that is higher than if that same cost were spread over a larger number of hours. Too few hours, it is more likely that customers will respond to the price signal, increasing the chance of actually moving the peak to a different time. On the other hand, too large a number of hours will dilute the price signal, resulting in more customers who contribute less to the actual capacity need paying more than perhaps they should.

Q. What period of hours is most appropriate for the billing of capacity-related costs?

A. In Staff's opinion, for classes with large numbers of diverse customers, on-peak summer kWh is the best starting point for billing these costs. Using summer months only, as opposed to the entire year, incorporates those months included in the calculation of the 4CP allocator which is used to determine cost responsibility for these capacity-related costs. At this point, narrowing the number of hours charged beyond this on-peak summer period unreasonably increases the risk of reaching an undesirable result. In addition, on-peak usage has long been an option for such customers, and should therefore be easier to understand than some other billing method. As classes contain fewer customers with more usage, one approaches the assumed perfect case of a one customer class, where any measure will result in the same cost responsibility to the customer. Additionally, these costs have already been charged to such customers on an on-peak billing demand basis for a number of years. Therefore, if the Commission decides that it is appropriate to bill costs differently across classes, such classes should continue to be billed on such a basis. However, if the Commission decides the costs must be billed the same to all classes, an on-peak kWh charge should be utilized. The result should be similar for the larger customers, and more accurate for the smaller.

Q. In brief, what is Staff's recommendation regarding the appropriate way to collect capacity-related costs?

A. Staff recommends that capacity-related costs be collected through summer on-peak kWh charges for rate schedules without demand charges, and through summer on-peak kW charges for rate schedules with demand charges. The resulting rate design and revenue by class is shown on Exhibits S-1.4-1.5, which is the final order rate design from MPSC Case No. U-18014 modified according to Staff's proposal. If the Commission decides that all customers must pay the same charge, capacity-related costs should be collected through a uniform summer on-peak kWh charge, calculated by dividing the total capacity-related cost by total on-peak summer kWh. Non-capacity power supply rates should then be modified to produce the same total revenue as the rates set in U-18014, using a method similar to that used in Exhibit S-1.5.

Q. What does 2016 PA 341 require as far as reconciliation?

A. 2016 PA 341 only requires a very limited reconciliation of the net revenues from energy market, off-system, ancillary service, and bilateral contract sales. The law states, in Section 6w(4):

> The commission shall provide for a true-up mechanism that results in a utility charge or credit for the difference between the projected net revenues described in subsection (3) and the actual net revenues reflected in the capacity charge. The true-up shall be reflected in the capacity charge in the subsequent year. The methodology used to set the capacity charge shall be the same methodology used in the true-up for the applicable planning year.

The plain language of the law makes it apparent that only the projected net revenues used in the calculation of the Capacity Charge need to be trued-up to actuals. Section 6w(3)(b) identifies the revenues and costs subjected to the true-up mechanism:

> [P]rojected 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.

Therefore, the necessary reconciliation will compare the actual revenue received from these four categories of revenue, net of the fuel costs which enabled them, to the projections used in setting the capacity charge. This difference is then to be reflected in the capacity charge in the next year.

Q. Are there any other costs currently subject to reconciliation included in the Capacity Charge?

A. Yes. Capacity-related costs associated with purchased power agreements (PPAs) are currently reconciled as part of the Power Supply Cost Recovery (PSCR) process.

Q. Does Staff agree with the Company's proposal to reconcile PSCR capacity costs?

A. Yes, but increased specificity on how the reconciliation should work would benefit the Commission's decision-making process. PSCR-related rates are split into two pieces: (1) the base, which is included in regular rates, and (2) the factor, which is intended to effectively increase or decrease the base throughout the year in order to minimize the over or under collection at the end of the year. The billed factor is set at the Company's discretion, subject to a cap. It is basically impossible to identify what costs are included in the base as opposed to the factor. Consequently, the best way to deal with potential mismatches between the amount of capacity-related costs incurred in a given year and the amount collected through the Capacity Charge is in the PSCR Reconciliation process. It would be reasonable to assume that the amount of Capacity Charge revenue associated with PPA capacity costs is proportionate to the amount of PPA capacity costs included as part of the calculation of the Capacity Charge. For example, if PPA Capacity costs are 5% of the total capacity-related costs used to calculate the Capacity Charge, 5% of the revenues received from that charge should be considered revenues to cover those same costs. Any difference between the collected revenue so calculated and the actual PPA capacity costs should be included in the calculation of the next year's Capacity Charge. This is the same treatment required for the net revenue reconciliation, and keeps the Company whole in the same manner the current PSCR reconciliation does.

Q. Does this complete your testimony?

A. Yes, it does.

JUDGE EYSTER: Anything else for Staff?

MS. DONOFRIO: And that is it for Staff.

JUDGE EYSTER: Thank you, Mr. Revere.

(The witness was excused.)

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JUDGE EYSTER: Mr. Boehm.

MR. BOEHM: Thank you, your Honor. I have two sets of testimony from Mr. Townsend. I understand that there is a motion to strike a portion of his direct testimony, so if we want to begin there.

JUDGE EYSTER: O.K. Mr. Middleton.

MR. MIDDLETON: Thank you, your Honor. In this proceeding, Kroger is sponsoring the direct testimony of Mr. Townsend. We have a very precise motion to strike that was filed. This portion that we seek to strike is related to aggregating load. This precise issue was already examined by the Public Service Commission in U-17767; they declined to adopt Kroger's position in that proceeding, and noting that adoption of such a position would create what they termed interclass subsidies; in other words, customers taking under the same tariff would be subjected to different rates. They said that's improper, and they declined to adopt Kroger's position. So as we've stated here in the written motion to strike, Kroger has resurrected the same exact position in this proceeding and attempted to bring it into this case as if this had anything to do with setting a capacity charge.

Other than that, I'll reserve some opportunity to rebut whatever Mr. Boehm has to say with regards to his response.

JUDGE EYSTER: Mr. Boehm.

MR. BOEHM: Thank you, your Honor. DTE's motion to strike is based on the misunderstanding that Mr. Townsend's proposal is, in the words of DTE, the exact same proposal that Mr. Townsend made in the 2015 rate case with regard to the now eliminated ELAP program. There are some similarities: Like the ELAP, Mr. Townsend's proposal in this case deals with the concept of demand aggregation, but that's where the similarities end. The ELAP program allowed qualifying multistate full-service, and that's the keyword, full-service customers to aggregate their billing demands across all their sites for power supply billing demand purposes. And one of the rationales for the ELAP program when it was in effect was that it allowed full-service customers to get similar treatment with respect to billing demand as retail open access customers. So now that we're in a case that deals with retail open access customers, the concept of aggregation is entirely appropriate.

The issue presented in the disputed portions of Mr. Townsend's testimony in this case relate solely to the determination of billing demands for billing open access customers and addresses the proper measurement of billing demand for retail open access customers for the purpose of implementing the SRM charge which is at issue here.

So just to recap, the distinction here is that the ELAP program dealt with full-service customers and the calculation of the demand component of their full-service rates. Here we're dealing with retail open access customers and the calculations of their SRM charge billing determinants. The issues are not the same, they're different, and the appropriate place for DTE to air any disagreement over Mr. Townsend's proposal is in briefs and not through a motion to strike.

JUDGE EYSTER: Mr. Middleton.

MR. MIDDLETON: Thank you, your Honor. I would point out that when the Commission rejected this exact same proposal in 17767, they noted with approval DTE Witness Mr. Bloch who stated, the fact that ELAP does nothing to alter the Company's costs or, important to this case, allocation of costs to cost of service classes and yet reduces rates is proof that ELAP is not cost-based.

So let's apply that to this case. We're here to set a capacity charge. The statute, Section 6w, requires that customers pay the same capacity charge whether they're Choice customers or whether they're bundled customers. We provided a case on behalf of DTE Electric in this proceeding that does exactly that, it takes every single tariff and it proposes a capacity charge for that tariff that applies either to Choice or to bundled customers.

Now, what would Kroger's proposal do? Kroger's proposal would say, no, that's not the case, we're not going to just have one rate and the same rate that applies to all customers within a tariff, we're going to have a rate for bundled customers, whether they can load aggregate or not, which they can't currently under our tariffs, and we're going to have two rates for Choice customers; one for Choice customers who are not load aggregating and one for those that are. That is exactly the same interclass subsidy and non-cost-based approach that the Commission rejected in 17767. It is identical.

This is a red herring to discuss this and claim that this is all about bundled versus Choice; it's not. It's about making sure that we adhere to the statute and that the same capacity charge is charged to all customers, whether they be Choice or bundled, not having two different classes of Choice customers under the same tariff, one who's load aggregating and one who's not. That has nothing to do with this case, it's changing billing determinants from one class of customers and not others within the same tariff, and that's inappropriate. And perhaps we could have argued about this but for the fact the Commission's already looked at it and said, no, you can't do that. Not appropriate.

You know, spending time -- there's plenty of issues for all of us to discuss and argue about in brief; this is one we shouldn't have to. So we renew our request to strike the portions indicated in our motion.

MR. BOEHM: Judge Eyster, may I respond?

JUDGE EYSTER: No, no, you don't need to.

I'm going to deny the motion. I think there's differences between this case and the Case U-17767. Now, the Commission could change its prior decisions, it's done that in the past, and they can take a look at this. And, Mr. Middleton, you made a great argument there for why the Commission shouldn't adopt the proposal; unfortunately, you'll have to make it to the Commission. O.K.

MR. BOEHM: O.K. Thank you, your Honor.

So Kroger has, as I said before, Kroger has two sets of testimony from Mr. Townsend. The first is the direct testimony of Neal Townsend, which consists of a cover sheet and six pages of questions and answers, there's no exhibits attached. The second is rebuttal testimony of Neal Townsend, which consists of a cover sheet and eight pages of questions and answers, with no exhibits attached. So Kroger would move that this testimony be bound into the record.

JUDGE EYSTER: Any objections?

The testimony is bound in.

Were there exhibits?

MR. BOEHM: No, your Honor.

JUDGE EYSTER: O.K.

(Testimony bound in.)

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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 Neal Townsend

on behalf of

The Kroger Co.

July 21, 2017

DIRECT TESTIMONY OF NEAL TOWNSEND

Introduction

Q. Please state your name and business address.

A. My name is Neal Townsend. My business address is 215 South State Street, Suite 200, Salt Lake City, Utah 84111.

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

A. I am a Principal at Energy Strategies, LLC. Energy Strategies is a private consulting firm specializing in economic and policy analysis applicable to energy production, transportation, and consumption.

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

A. My testimony is being sponsored by The Kroger Co. ("Kroger"). Kroger is one of the largest retail grocers in the United States, and operates more than 80 facilities in the territory served by DTE Electric Company ("DTE" or the "Company"). DTE delivers more than 200 million kWh annually to Kroger's facilities, which are mostly served under Rate Schedule No. D11, Primary Supply Rate. The majority of Kroger's accounts receive Retail Access Service, but some of Kroger's accounts receive Full Service from DTE.

Q. Please describe your educational background.

A. I received an MBA from the University of New Mexico in 1996. I also earned a B.S. degree in Mechanical Engineering from the University of Texas at Austin in 1984.

Q. Please describe your professional experience and background.

A. I have provided regulatory and technical support on a variety of energy projects at Energy Strategies since I joined the firm in 2001. Prior to my employment at Energy Strategies, I was employed by the Utah Division of Public Utilities as a Rate Analyst from 1998 to 2001. I have also worked in the aerospace, oil and natural gas industries.

Q. Have you previously testified before this Commission?

A. Yes. I provided testimony in DTE's last three general rate cases, Case Nos. U-18014, U-17767 and U-16472. I also provided testimony in Consumers Energy Company's last six general rate cases, Case Nos. U-17990, U-17735, U-17087, U-16794, U-16191 and U-15645.

Q. Have you testified before utility regulatory commissions in other states?

A. Yes. I have testified in utility regulatory proceedings before the Arkansas Public Service Commission, the Illinois Commerce Commission, the Indiana Utility Regulatory Commission, the Kentucky Public Service Commission, the New Mexico Public Regulation Commission, the Public Utilities Commission of Ohio, the Public Utility Commission of Oregon, the Public Utility Commission of Texas, the Utah Public Service Commission, the Virginia Corporation Commission, and the Public Service Commission of West Virginia.

Overview and Conclusions

Q. What is the purpose of your testimony in this proceeding?

A. In its March 10, 2017 Order, the Commission ordered parties to address issues related to the SRM charge, including the term of the State Reliability Mechanism

(SRM) and the true-up methodology related to implementation of Section 6w of 2016 Public Act 341 (PA 341) in testimony. Specifically, my testimony addresses the following pertinent to DTE's SRM case filing:

(1) DTE's proposal that retail open access ("ROA") customers returning to Bundled Service or taking Utility Capacity Service from DTE be required to pay DTE's SRM capacity charge for 30 years; and

(2) The proper billing units for any SRM capacity charge levied on ROA customers.

Q. Are you providing an opinion as to the appropriateness of DTE's derivation of its proposed capacity charge in satisfying the requirements of Section 6w?

A. No, I am not opining as to whether or not DTE's proposed capacity charge satisfies the requirements of Section 6w. My testimony is limited only to the appropriate term and proper billing units for whatever SRM charge is ultimately implemented by the Commission.

Q. What recommendations do you present in your testimony?

A. Based on my review of DTE's direct filing:

(1) DTE's proposal that ROA customers returning to Bundled Service or taking Utility Capacity Service be required take capacity service for 30 years should be rejected by the Commission.

(2) If an ROA customer purchases capacity in the first four years of the SRM, the ROA customer should be required to purchase the capacity for no more than four years during the first four years of the SRM.

After that, an ROA customer should be able to purchase capacity on a year to year basis if notice is given four years in advance.

(3) The billing demand for a multi-site ROA customer that is purchasing SRM capacity service should be based on the individual customer's aggregated demand across its various sites.

<u>Capacity Charge Term</u>

Q. Please describe DTE's proposal related to the appropriate term for the capacity charge.

A. According to the Direct Testimony of Don. M. Stanczak, DTE proposes that ROA customers returning to Bundled Service or taking Utility Capacity Service will be required to take capacity service from the Company for 30 years.

Q. What reasons does Mr. Stanzcak's give to support his 30 year proposal?

A. Mr. Stanczak maintains that any DTE investment in new generating plants will have operating lives of 30 years or more and the generation capacity charge should remain in place for at least the minimum expected life of these new facilities.

Q. What is your response to DTE's proposal that ROA customers returning to Bundled Service or taking Utility Capacity Service be required take capacity service for 30 years?

A. DTE's proposal is draconian, over-reaching, and unreasonable. It should be rejected by the Commission. It would establish a 30-year obligation on the part of an ROA customer that required capacity service even for a relatively short period of time to be in compliance with the SRM established under PA 341. Yet, PA 341 only requires that an ROA customer needing utility capacity commit to a four-year obligation, if the capacity is purchased in the first four years of the SRM, and after that, on a year to year basis if notice is given four years in advance. Rather than agreeing to DTE's proposed 30-year term, the Commission should require a term that is accord with the statute. If the capacity is purchased in the first four years of the SRM, the ROA customer should be required to purchase the capacity for no more than four years during the first four years of the SRM. After that, customers should be able to purchase capacity on a year to year basis if notice is given four years in advance.

Billing Units for SRM Capacity Charge

Q. How should the billing demand for the SRM capacity charge applicable to an ROA customer be determined?

A. The billing demand for an ROA customer that is purchasing SRM capacity should be based on the individual customer's aggregated demand across its various sites, as applicable. That is, rather than billing a multi-site ROA customer for capacity based on each individual site's maximum on-peak demand, the multi-site ROA customer should be treated as a single customer for the purpose of determining its capacity billing demand. Therefore, its billing demand for capacity should be based on its aggregate hourly demand across all of its sites that are subject to the SRM capacity charge.

By treating the multiple loads of a single customer as a single entity for the purpose of measuring the amount of capacity provided to the ROA customer, the customer's load is treated in a manner that is comparable to its treatment in the competitive market. To determine the proper amount of capacity to provide a multi-site load, a competitive energy supplier aggregates the load. In this respect, the multi-site load would be treated in the same manner as a single site. To maintain consistency in billing the multi-site load for capacity, the loads should also be aggregated.

Q. Is it reasonable for multi-site customers and single-site customers to be treated on an equal footing when it comes to capacity costs?

A. Yes. From a capacity supply perspective it makes no difference whatsoever whether 10 MW in a given hour is going to a single-site customer with a 10 MW load or to a multi-site customer with five facilities taking 2 MW each. The cost to provide capacity to the 10 MW of load is identical in both cases. Therefore, in this fundamental sense, load aggregation is cost-based.

Q. Does this conclude your direct testimony?

A. Yes, it does.

STATE OF MICHIGAN
BEFORE THE 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**

AFFIDAVIT OF NEAL TOWNSEND

STATE OF UTAH)
)
COUNTY OF SALT LAKE)

Neal Townsend, being first duly sworn, deposes and states that:

1. He is a Principal with Energy Strategies. L.L.C., in Salt Lake City. Utah;

2. He is the witness who sponsors the accompanying testimony entitled "Direct Testimony of Neal Townsend;"

3. Said testimony was prepared by him and under his direction and supervision;

4. If inquiries were made as to the facts and schedules in said testimony he would respond as therein set forth; and

5. The aforesaid testimony and schedules are true and correct to the best of his knowledge, information and belief.

Neal Townsend

Subscribed and sworn to or affirmed before me this 21st day of July, 2017 by Neal Townsend.

Notary Public

Notary Public
Kimberlie A. Ignjatovic
Commission #682578
My Commission Expires
April 10, 2019
State of Utah

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

Rebuttal Testimony of Neal Townsend

on behalf of

The Kroger Co.

August 16, 2017

DIRECT TESTIMONY OF NEAL TOWNSEND

Introduction

Q. Please state your name and business address.

A. My name is Neal Townsend. My business address is 215 South State Street, Suite 200, Salt Lake City, Utah 84111.

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

A. I am a Principal at Energy Strategies, LLC. Energy Strategies is a private consulting firm specializing in economic and policy analysis applicable to energy production, transportation, and consumption.

Q. Are you the same Neal Townsend who provided Direct Testimony, on July 21, 2017, on behalf of The Kroger Co. ("Kroger")?

A. Yes, I am.

Overview and Conclusions

Q. What is the purpose of your testimony in this proceeding?

A. My rebuttal testimony responds to the direct testimony of Staff witness Nicholas M. Revere and Association of Businesses Advocating Tariff Equity (ABATE) witness James R. Dauphinais regarding the appropriate rate design for the SRM capacity charge and remaining rate elements for demand-billed customers.

Q. Please summarize the conclusions of your rebuttal testimony.

A. 1) I recommend that Staff's proposal to recover capacity-related costs solely through summer on-peak kW charges for demand-billed customers be rejected by the Commission, as such a rate design is inconsistent with the nature of the underlying costs and incorporates a radical and unnecessary change in rate design that would result in unwarranted intra-class cost shifting among bundled service customers. However, I support Staff's rate design *as it is laid out in Exhibit S-1.5* for demand-billed customer classes. As presented in that exhibit, which is inconsistent with the description in Staff's testimony, Staff's rate design utilizes a year-round capacity demand charge. The rate design also recovers non-energy costs that are not SRM capacity related through a Power Supply demand charge.

2) I recommend that Mr. Dauphinais' proposal to recover demand-related costs that are not SRM-capacity-related through a non-capacity *energy* charge for demand-billed customers be rejected by the Commission, as such a rate design is inconsistent with the nature of the underlying costs and would result in unwarranted intra-class cost shifting among bundled service customers.

<u>Response to Mr. Revere</u>

Q. What is Mr. Revere's recommendation regarding the determination of capacity-related costs for the purpose of calculating the SRM capacity charge per 2016 PA 341 Section 6w(3)?

A. According to Mr. Revere's testimony, Staff believes that the cost of capacity is the Cost of New Entry, or the cost to build a combustion turbine. However, Staff uses an alternative approach to identify capacity-related costs based on the approved cost-of-service study from Case No. U-18014. Staff first identified the costs currently allocated using the 4CP (four coincident peak)/ 75-25 production cost allocator. Of these costs, Staff classified the 75% portion allocated on 4CP as capacity-related and considers the remaining 25% portion non-capacity related costs. According to Mr. Revere, not all costs that are not energy-related are capacity-related; such costs would more properly be considered *non-energy* costs.[1]

Q. How does Staff propose to allocate its proposed capacity and non-energy costs to classes and recover the costs from customers?

A. Mr. Revere recommends that these costs be allocated to the classes based on the results of the class cost-of-service study approved in Case No. U-18014, reflecting the cost responsibility that is currently in place.[2] In Mr. Revere's testimony, he recommends that the proposed capacity-related costs be recovered through summer on-peak kWh charges for rate schedules without demand charges, and through summer on-peak kW charges for rate schedules with demand charges.[3] Based on Staff's rate design in Exhibit S-1.5, for schedules with demand charges, it appears that the capacity costs are recovered through the SRM capacity demand charge while the non-energy costs are recovered through a Power Supply demand charge. Notably, in my examination of Staff's rate design in Exhibit S-1.5, it does not appear that Staff has actually designed the SRM

[1] Direct Testimony of Nicholas M. Revere, pp. 5-7.
[2] *Id.*, pp. 8.
[3] *Id.*, pp. 12.

capacity demand charges to recover those capacity costs exclusively in the summer months as indicated in Mr. Revere's testimony, but rather the capacity demand charges have been designed to recover the SRM capacity costs through demand charges that are levied year-round.

Q. Do you agree with Staff's proposal to recover all capacity-related costs through summer on-peak charges?

A. No. I do not agree with Staff's proposal, *as described in Mr. Revere's testimony*, which would recover the entirety of the SRM capacity-related costs for demand-billed customers through a summer on-peak demand charge.[4] This change would constitute a radical departure in rate design that goes well beyond the fundamental issue in this proceeding of developing an SRM capacity charge. Today, capacity-related costs are recovered year-round through the demand charge. The current rate design smoothes out the recovery of capacity costs throughout the year. This basic design was determined to be just and reasonable in the last general rate case and in numerous prior proceedings. There is no reason to switch to a dramatically different rate design simply to develop a new SRM capacity charge.

Loading the entirety of capacity-related cost recovery into the four summer months would dramatically increase summer bills for bundled service customers. Bundled service customers should not be subject to the significant cash flow spikes that would result simply to accommodate a new SRM capacity charge – particularly when such a change is completely unnecessary. The SRM capacity charge can recover capacity costs throughout the year just as the current

[4] *Id.*, pp. 12.

demand charge does. Indeed, a year-round capacity charge is proposed both by DTE and by Mr. Dauphinais.

Yet, as I discussed above, notwithstanding the proposal in Mr. Revere's testimony to shift all capacity charges to the summer, it does not appear that Mr. Revere's Exhibit S-1.5 actually calculates the capacity demand charges in a manner that would recover those capacity costs solely through summer on-peak kW charges, but rather recovers those capacity costs through year-round peak demand charges. Thus, while I *disagree* with the summer capacity proposal described in Mr. Revere's *testimony*, I *support* a rate design that recovers the capacity costs through a year-round capacity demand charge as shown in his *Exhibit S-1.5*.

Q. Staff's Exhibit S-1.5 shows a Power Supply demand charge that is separate from the SRM capacity charge. Do you wish to comment on this?

A. Yes. I believe that a Power Supply demand charge that recovers non-energy costs from demand-billed customers, and which is not part of the SRM capacity charge, is entirely appropriate. Such a charge is consistent with the statement in Mr. Revere's testimony that not all costs that are not energy-related are necessarily capacity-related,[5] a point with which I agree. Not all costs that support the production demand function are necessarily reliability-related and such non-energy costs are most appropriately recovered through demand charges from demand-billed bundled service customers rather than through energy charges.

[5] *Id.*, p. 6.

Q. What is your recommendation regarding Staff's rate design proposal?

A. I support Staff's rate design *as it is laid out in Exhibit S-1.5* for demand-billed customer classes. As presented in that exhibit, Staff's rate design recovers non-energy costs that are not capacity-related through a demand charge and utilizes a year-round capacity demand charge.

However, to the extent that Staff modifies Exhibit S-1.5 to recover all capacity charges through a summer demand charge, and/or converts the Power Supply demand charge in that exhibit to an energy charge, then I recommend that proposal be rejected by the Commission. Such modifications would constitute a radical and unnecessary change in rate design that would result in unwarranted intra-class cost shifting among bundled service customers.

<u>Response to Mr. Dauphinais</u>

Q. What is Mr. Dauphinais' recommendation regarding the determination of capacity-related costs for the purpose of calculating the SRM capacity charge per 2016 PA 341 Section 6w(3)?

A. Mr. Dauphinais recommends that the Commission require DTE to revise its classification of production costs between capacity-related and non-capacity related costs for schedules with ROA customers. According to Mr. Dauphinais, the 25% of fixed production costs that is allocated on an energy usage basis should be classified as a non-capacity related production cost. Mr. Dauphinais proposes a rate design that removes the 25% energy-allocated amount from the total capacity costs,[6] and recovers that portion of costs through an increased non-capacity energy charge.[7]

Q. Do you agree with Mr. Dauphinais' recommendation to recover the 25% of fixed production costs allocated on an energy usage basis through an increase in the non-capacity energy charge?

A. No. Mr. Dauphinais' approach is inconsistent with the nature of the underlying costs. While it may be reasonable to exclude certain Power Supply related costs from the SRM capacity charge, that does not make them energy-related. It is unreasonable to shift recovery of Power Supply costs to the energy charges as Mr. Dauphinais proposes. Doing so would shift cost recovery among bundled service customers within each demand-billed class, as customers with higher-than-average load factors would be assigned greater responsibility for recovery of Power Supply costs than under current bundled rates. Consequently, these costs should continue to be recovered from bundled service customers through a demand charge for those customers that are demand-billed. The development of an SRM capacity charge should not be a vehicle for unwarranted intra-class cost shifting among bundled service customers.

Further, Mr. Dauphinais' proposed rate design appears to recover transmission expense in the power supply energy charges, which is inconsistent with the demand-related nature of these costs. There is no basis for classifying transmission expenses as anything but demand-related, so they are properly

[6] Direct Testimony of James R. Dauphinais, pp. 20-21.
[7] Exhibit AB-2 (JRD-2).

recovered through a non-capacity demand charge, i.e., a demand charge that is not part of SRM capacity cost recovery.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

STATE OF MICHIGAN
BEFORE THE 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**

AFFIDAVIT OF NEAL TOWNSEND

STATE OF UTAH)
)
COUNTY OF SALT LAKE)

Neal Townsend, being first duly sworn, deposes and states that:

1. He is a Principal with Energy Strategies. L.L.C., in Salt Lake City. Utah;

2. He is the witness who sponsors the accompanying testimony entitled "Rebuttal Testimony of Neal Townsend;"

3. Said testimony was prepared by him and under his direction and supervision;

4. If inquiries were made as to the facts and schedules in said testimony he would respond as therein set forth; and

5. The aforesaid testimony and schedules are true and correct to the best of his knowledge, information and belief.

Neal Townsend

Neal Townsend

Subscribed and sworn to or affirmed before me this 16th day of August, 2017 by Neal Townsend.

Kimberlie A. Ignjatovic

Notary Public

Notary Public
Kimberlie A. Ignjatovic
Commission #682578
My Commission Expires
April 10, 2019
State of Utah

JUDGE EYSTER: All right. Mr. Moody, would you like to go?

MR. MOODY: Your Honor, the Attorney General didn't file direct testimony in this case. Thank you.

JUDGE EYSTER: All right. Ms. Heston.

MS. HESTON: Thank you, your Honor. Pursuant to the stipulation of the parties and agreement to waive cross-examination of Constellation NewEnergy's witness, Dr. Makholm, at this time I move to bind into the record the prefiled direct testimony of Jeff D. Makholm, Ph.D, that was filed on behalf of Constellation NewEnergy in this proceeding on July 21. The testimony consists of a cover page, 39 pages of questions and answers, and then an Attachment A, which consists of 27 pages. I also move to admit into evidence the prefiled exhibits that were sponsored by Mr. Makholm, which are marked as Exhibits CNE-1 and CNE-2.

JUDGE EYSTER: Any objections?

Hearing none, the testimony is bound in and the exhibits are admitted.

(Testimony bound in.)

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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.	)	
_______________________________________	)	

DIRECT TESTIMONY AND EXHIBITS OF

JEFF D. MAKHOLM, Ph.D.

On behalf of

Constellation NewEnergy, Inc.

July 21, 2017

I. Introduction and Summary Conclusions

Q1. Please state your name, business address and current position.

A1. My name is Jeff D. Makholm. I am a Senior Vice President/Managing Director at National Economic Research Associates, Inc. ("NERA"). NERA is a firm of consulting economists with its principal offices in a number of major cities in the United States and around the world. My business address is 200 Clarendon Street, Boston, Massachusetts, 02116. I have been with the firm since 1986.

Q2. Please describe NERA.

A2. NERA was founded in 1961 by consulting economists working in conjunction with Professor Alfred E. Kahn of Cornell University (a founder and longtime Special Consultant at NERA), making it the oldest firm of independent consulting economists. Among other areas of economics applied to industrial organization, regulation and economic trade questions, NERA has been heavily involved in the definition and creation of competitive energy markets in the United States and around the world. NERA's participation in the restructuring of US gas markets started before its 1961 founding and continued through the highly successful creation of competitive markets for both gas and interstate transport. NERA was also the leading economic consulting firm for the electricity industry throughout the 1980s and was the consultant to the UK's Central Electricity Generating Board in creating the first competitive power market concurrent with the privatization of the electricity industry there.

Q3. Please describe your academic background and experience.

A3. I have M.A. and Ph.D. degrees in economics from the University of Wisconsin, Madison, with a major field of Industrial Organization and a minor field of Econometrics/Public Economics. My 1986 Ph.D. dissertation is entitled "Sources of Total Factor Productivity in the Electric Utility Industry" (where I applied index number theory to chart productivity advances for the US steam-electric utility industry—including for operating power plants in Michigan). I also have B.A. and M.A. degrees in economics from the University of Wisconsin, Milwaukee. I joined NERA in 1986. Prior to my latest full-time consulting activities, I was an Adjunct Professor in the Graduate School of Business at Northeastern University in Boston, Massachusetts, teaching courses in microeconomic theory and managerial economics.

Q4. Please describe your work experience pertinent to this proceeding.

A4. My work as a consulting economist principally involves the area of regulated industries—both those that operate networks (such as oil and gas pipelines, electricity transmission and gas distribution systems, telecommunications and water utility systems) and those operating infrastructure businesses at specific sites, such as airports, electricity generation plants, oil refineries and sewage treatment plants. In such industrial settings, I have researched and provided evidence regarding regulated pricing, the presence or absence of market power, competition, the fair rate of return, regulatory rulemaking, incentive ratemaking, load forecasting, least-cost planning, cost measurement, contract obligations and bankruptcy, among other issues. I have prepared expert testimony and affidavits, and I have appeared as an expert witness in many state, federal and United States District Court proceedings, as well as in regulatory and court proceedings abroad.

I have also directed studies on behalf of utility companies, governments and the World Bank in many countries: drafting regulations, establishing tariffs, recommending financing options for major capital projects and advising on industry restructurings. I have also assisted in the privatization of state-owned utilities. As part of my international work I have conducted formal training sessions for government, industry and regulatory personnel on the subjects of privatization, pricing, finance and regulation of the gas industry. I provide my current curriculum vitae, which more fully details my educational and consulting experience and my publications as Appendix A to my testimony.

Q5. What is the purpose of your testimony?

A5. I appear on behalf of Constellation NewEnergy, Inc. ("CNE"), an active alternative electric supplier ("AES") in the service territory of DTE Electric Company ("DTE" or "the Company"). CNE has direct interest in the rates, terms, and conditions proposed in this proceeding as a participant in the Electric Choice Market. I have been asked to provide an economic analysis of the Company's proposed State Reliability Mechanism ("SRM") charge mandated by Section 6w of Public Act 341 of 2016 ("Act 341"). My testimony refers to the SRM proposed by DTE Electric Company.

Q6. How do you organize your testimony?

A6. After presenting briefly my main conclusions, I organize my testimony in two successive sections dealing with: (1) problems with the methods proposed by DTE to compute its

SRM that appears to me inconsistent with the SRM legislation, and my proposed remedy to those problems; and (2) my reply to other issues raised in DTE's SRM proposal, including DTE's proposed 30-year term for the SRM charge and its proposal to place AES customers returning to the Company for capacity service on interruptible service in the event there is not sufficient capacity to ensure firm service.

Q7. What do you conclude from your analysis in this case?

A7. I conclude the following:

- The SRM is unique to Michigan's hybrid approach to adopting electricity competition whereby both utilities (with their own regulated resources) and AESs (with unregulated resources) provide electricity services to consumers. The SRM capacity charge seeks to reflect *that portion* of the utilities' regulated costs needed to meet the peak system load that will apply both to utility and AES customers.

- The distinction between *energy* and *capacity* is of paramount importance in determining such a charge. The best and most economically useful way to compute a reasonable SRM is to reference a planning model that combines projected AES and bundled customer capacity requirements as distinct from energy requirements.

- DTE has not employed such a planning model. Rather, DTE uses a split between its fixed and variable production plant (and purchased power) embedded cost of service to compute its **$436/MW-day** SRM charge.

- Despite the inherent desirability of using a planning model for determining an SRM charge, there are accepted methods to distinguish between energy and capacity costs with the use of embedded cost data. I compute a figure of **$224/MW-day** using such a method—less than half of DTE's computation of $436/MW-day. My $224 computation is likely to be overstated even then, given that peaking capacity resources are assumed to be less expensive per MW than energy-related base load units.

- It is possible to use other benchmarks on the cost of new capacity to check these embedded cost computations. One is the latest "cost of new entry" ("CONE") of **$260.00/MW-day** as filed with the Federal Energy Regulatory Commission ("the FERC) for the 2017-2018 planning years by MISO (the Midcontinent Independent System Operator, Inc.).

- Another benchmark comes from Consumers Energy Company's RFP for demand side zonal resource credits (ZRCs) of **$164/MW-day**.[1] While DTE did not issue this RFP, it provides a reasonable benchmark for ZRCs in MISO Zone 7.

- The Company's proposed 30-year term of service for SRM service to AES customers is unreasonable—as it pre-supposes that DTE would take on the cost and risk of building new rate-based power plants rather than accessing the forward price for additional capacity to deal with any needed coverage of capacity for AES purposes.

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[1] Case No. U-18382, In the matter of the application of Consumers Energy Company for approval of long-term power purchase agreements. Testimony of David F. Ronk, Jr., page 10.

- DTE's proposal to provide interruptible service to AES customers when it experiences a shortfall in capacity is unreasonable and unworkable under the Section 6w legislation, which mandates that all customers taking the capacity charge are treated equally and receive the same service.

I recommend that the Commission adopt a range of $164 to $260/MW-day, using available benchmarks for capacity prices in the region, given the absence of a DTE planning model to determine the costs of serving incremental capacity.

II. Section 6w SRM Capacity Charges for DTE

Q8. Before specifically examining DTE's quantification of its proposed SRM capacity, do you have anything of a preliminary nature that you would like to say as a way of putting that charge in context?

A8. Yes. The context is critical to understanding what the SRM charge is for.

Prior to the Section 6w implementation, the incumbent regulated utilities in Michigan did not need to include the 10 percent of customers on retail choice in their capacity plans. Now, according to the Section 6w legislation, they must add certain AES customers into their planning process as potentially capacity-only customers; that is, customers with potential capacity demands but no expected loads on the system.

The key to a proper charge is not what the bundled utility customers see in their bills, but what AES customers would see in theirs, in the event that the SRM charge would apply to them. The reason is that the utility customers purchase both year-round energy and peak capacity from the utilities; how utilities split their regulated costs of providing such full service to bundled utility customers is, at most and apart from any other changes in the basic design of rates, a relabeling of the total regulated utility power supply costs that full-service customers already pay.

AES customers, however, place no energy demands on the utility. To them, the SRM capacity charge, if they have to pay it, would be new and incremental—not merely a relabeling of what they already pay. Thus, a "cost-effective, reasonable and prudent" SRM must take into account the benefit that AES customers would receive on a going-forward basis if they end up relying upon the utility reliably to serve their capacity loads.

By using a planning model, DTE could have calculated an SRM charge that reflects its going-forward capacity-only costs during the applicable term of the capacity charge, as required under Section 6w(3). Indeed, in discovery requests, I asked DTE whether it had used its supply planning model to derive its SRM: the Company said that it did not.[2]

Rather than employ a planning model to separate out capacity from energy requirements for the purpose of computing the SRM charge, DTE computes its charge based on a split between its fixed and variable embedded cost of service. To be sure, computing a forward-looking SRM grounded in embedded cost computations is more advantageous for the utility than using an incremental or marginal cost computation that alternative runs of DTE's planning model would produce. I am thus not surprised that DTE turned to embedded cost computations for its proposed SRM charge.

[2] Case No. U-18248, DTE Response to Constellation NewEnergy, Inc. Discovery Request Question No. CNEDE-1.4a-1.4d, CNEDE-1.6, attached as (Exhibit CNE-1 (JDM-1).

Nevertheless, even using such embedded cost methods, it is apparent that DTE's SRM overstates what a reasonable capacity-only (that is, not energy) charge should be. The reason is that DTE did not take into account the fact that AES customers place no energy demands on the DTE system—only prospective and potential capacity demands. Traditional, embedded-cost methods recognize the "evidence that energy loads are a major determinant of production plant costs."[3] Embedded cost methods that reflect such a distinction between energy and capacity would thus be more applicable for the computations of the SRM charge.

Q9. What did DTE use as the basis for its proposed SRM capacity charges?

A9. DTE calculates the SRM capacity charge based on the revenue requirement approved in its last rate case (U-18014). DTE assumes that no electric choice load will require SRM capacity from DTE—and, as such, its SRM rates "are revenue neutral."[4] Mr. Don M. Stanczak proposes an indefinite term for the SRM and a 30-year term for the associated SRM capacity charge.[5]

Mr. Phillip W. Dennis proposes SRM Capacity Charge filings each year and related timelines.[6] Mr. Thomas W. Lacey calculates DTE's SRM Capacity Charge revenue requirement starting with DTE's most recently approved rate case cost of service model and projected energy sales net of projected fuel costs, which Witness Angela P.

[3] National Association of Regulatory Utility Commissioners (NARUC) Electric Utility Cost Allocation Manual, January, 1992, p. 49.

[4] DTE Electric Company Application, p.3.

[5] Direct Testimony of Don M. Stanczak, pp. DMS-5-6.

[6] Direct Testimony of Phillip W. Dennis, Exhibit A-16.

Wojtowicz presents in her testimony.[7] Mr. Timothy A. Bloch (Commercial and Industrial Primary Rate Classes), Ms. Kelly A. Holmes (Commercial Secondary and Lighting Rate Classes), and Mr. Michael A. Williams (Residential Rate Classes) present customer rates derived from Mr. Lacey and Ms. Wojtowicz's calculations.[8]

Q10. How does DTE compute its proposed SRM charge?

A10. Mr. Lacey provides DTE's calculation of the capacity related revenue requirement starting with the production related revenue requirement derived in the cost of service model from DTE's most recent general rate case. In Exhibit A-14, Mr. Lacey then subtracts the following items from this revenue requirement: projected energy sales net of projected fuel costs, which is calculated by Ms. Wojtowicz, fuel expenses, purchase power costs from MISO for Rider 3 and Rider 10 and variable O&M costs.[9] These items are effectively classified as "non-capacity" costs. DTE identifies the difference between these non-capacity costs and the production related revenue requirement (the "capacity revenue requirement") and uses that value to calculate the SRM charge.[10] This methodology does not directly classify capacity costs, but instead, classifies all costs not included as non-capacity as part of the capacity portion of DTE's business.

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7 Direct Testimony of Thomas W. Lacey and Direct Testimony of Angela P. Wojtowicz, Exhibit A-10, April 11. 2017.

8 Direct Testimony of Thomas W. Lacey, Timothy A. Bloch, Kelly A. Holmes, and Michael A. Williams.

9 Direct Testimony of Thomas W. Lacey and Direct Testimony of Angela P. Wojtowicz, Exhibit A-10, April 11. 2017.

10 Direct Testimony of Thomas W. Lacey, pp. TWL-5 – TWL-6.

Q11. What is your opinion of such a method for computing the SRM?

A11. In my opinion, DTE's methodology for calculating a SRM charge does not get at what the legislation is after—an SRM, which would be applicable both to AES and utility customers, that ensures that "non-capacity electric generation services are not included in the capacity charge."[11]

Q12. Why not?

A12. Such a method only serves roughly to segregate fixed costs from variable costs. It does not reflect, and has no practical possibility of finding, an *SRM capacity charge* that deals reasonably with the problem that Section 6w seeks to remedy—which is to establish a "cost-effective, reasonable and prudent" mechanism to ensure reliability. The legislation seeks to ensure sufficient capacity resources at the "forecasted coincident peak demand" plus a reserve margin.[12] In contrast, DTE's proposed "capacity charge" is made up of the entirety of its non-variable costs unrelated to any measure of peak reliability, as such. DTE's charge is not related to "capacity" in any way consistent with what the legislation appears to be seeking. DTE's method is simply a fixed cost-related charge that does not recognize that many of DTE's fixed embedded costs are related to providing *energy*—a service that AES customers do not receive from DTE.

Q13. In your opinion is DTE's method consistent with the Section 6w legislation?

A13. No. I see no economic way to reconcile the legislation's call for an SRM that ensures that "non-capacity electric generation services are not included in the capacity charge"

[11] Sec. 6w (3), Act 341.
[12] Sec. 6w (12) (e), Act 341.

with DTE's method. If all that the legislation were after was to apportion to AES customers a *pro rata* share of DTE's non-variable costs—precisely what DTE has done—then there would be no need in the legislation to describe in detail how to tie the SRM capacity charge to those forward-looking, forecasted costs that would apply to AES load.

Q14. You mentioned the "cost effective, reasonable and prudent" language at the outset of your testimony. How does Section 6w use those words?

A14. Section 6w uses these words in relation to a finding regarding the SRM as "more cost effective, reasonable and prudent" than a MISO capacity forward auction.

Q15. If there is to be no capacity forward auction, and thus no choice for the Commission to make, do those words still mean something as an economic matter?

A15. They do. Although the Commission's determination of whether a SRM is "more cost-effective, reasonable, and prudent" than a capacity forward auction would seem not to be required because there is no capacity forward auction to compare with a SRM, by implication the legislation still requires the SRM to be cost-effective, reasonable and prudent. The legislation contains sufficient references to markets, planning, resource adequacy and peak requirements to put the words "cost-effective, reasonable and prudent" in context as an economic matter. If the SRM is to make any sense in what AES providers should pay to cover DTE's costs to deal with its system peak, the charge cannot exist apart from the reasonable costs of doing so—mindful of objective planning scenarios and viable benchmarks for the cost of new entry into the market for power.

Q16. How do electric utilities like DTE plan for their future system needs?

A16. When planning an electric system, all utilities, including DTE, follow a process that, while perhaps varying in particular details, has three essential steps:

1. Itemize the existing resources available to meet current loads. Such resources include owned-and-operated capacity, capacity under contract, interruptible loads and import capabilities.
2. Forecast loads over some future period.
3. Calculate incremental resources to meet these future loads (including acceptable reserve margins) over that future period at least cost. The incremental resource plan includes retirements and additions—the latter which may come from new utility-built plants, new contracted supplies, purchase in local power markets, imports from neighboring power markets, expansion of interruptible supplies and/or demand side management, or any other potential new resources.

Q17. What is a "least cost plan"?

A17. A least cost plan determines the most reasonable way to spend money to meet forecasted loads. A least cost plan for resources, combined with the load projection, produces expected costs through a production simulation model. With such a model, the utility can compute directly incremental cost, average cost, or any other sort of cost or rate required to fund all of the resources to meet projected loads. The utility can also determine such costs indirectly through variations in the plan. Variations in peak demand, for example, yield incremental capacity costs and variations in kWh demanded produce incremental energy costs.

Q18. How does the Section 6w legislation change the planning process for DTE?

A18. The change is straightforward. Whereas prior to the passage of Section 6w, DTE could ignore the 10 percent of customers on retail choice, now they must add those customers into their planning process as *capacity-only customers*, i.e. customers with potential demands but no expected loads on the system. The system design must change.

Q19. Is the calculation itself straightforward for DTE?

A19. Yes. The incremental capacity cost of the retail choice customers should be easy for DTE to calculate: it is simply the extra capacity associated with an increase in peak load with no corresponding energy needed.

Such customers can be supplied in many ways, most typically by a resource with very low capital costs and very high operating costs—classic examples would be diesel engines, demand response, or possibly a simple cycle peaker plant. Imports of capacity unutilized in other regions is another obvious potential source of incremental capacity, particularly in the short run when observed market prices are lower than the cost of new entry.

Q20. When calculating an appropriate SRM charge, why focus on contribution to peak load?

A20. The purpose of the SRM is to ensure system reliability. To ensure system reliability, load serving entities must have sufficient capacity to meet peak demand plus a reserve.

Q21. If the SRM charge is modeled at the system peak, does it also ensure reliability at other non-peak times?

A21. Yes. Although such a calculation comes from the system peak, it will equally well provide capacity at loads less than the system peak, since sufficient capacity to provide backup at peak times provides even more of a margin at all other times.

Q22. Can you provide an example that puts these principles in action?

A22. Yes. A couple of examples would be useful.

Consider first a scenario with only fully-bundled utility customers—that is, without any AES customers. Label as "System A" a system designed by a planning model with sufficient capacity to serve the anticipated loads of such bundled customers, and no more. Label as "System B" a system designed simply to provide energy alone to such customers (as if storing electricity were costless). Such a system with a planning model cost of System A is clearly well overbuilt to provide energy alone, as System A is designed to handle uneven loads and System B (in which I postulate that customers take at 100 percent load factors) is not. The least cost plan to provide energy only to bundled service customers would retire or mothball the least efficient units, saving their fixed operating and maintenance costs.[13] The difference between the full revenue requirement costs of the two systems (System A minus System B) is exactly the cost of service to provide capacity to the bundled service customers over the cost of service to provide energy alone.

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[13] Of course, the undepreciated capital cost is still part of this hypothetical utility's property and would need to be recouped in some fashion outside of my example.

In other words, simply providing energy requires the payment of fixed costs—from utility-built plants, new contracted supplies, purchases in local power markets, etc. Dealing with the capacity at the peak of the system—the consideration that most spurs the Section 6w legislation—requires only the increment above the cost of service that would be required to serve a system without such anticipated peaks.

Note that in this example we did not need any complex characterization of what were and were not capacity costs. In order to provide energy, you have to have generating capacity (or its equivalent in purchases). "Capacity costs" in the Section 6w sense, in my opinion, are those costs above and beyond those needed to provide energy.

Q23. What happens when you add AES customers to such an example that distinguishes between the capacity needed only to support energy-only service (B) and the uneven loads on the system (A)?

A23. Since AES customers get their energy from their retail energy firms, they add *capacity-only* demands to the system. The planning models will specify that the utility must *do something* to deal with those capacity-only AES demands (*e.g.*, the purchase of imports, signing up additional interruptible loads or other demand side management customers, delays in planned retirements or possibly new plant construction—probably peaking plants—to meet this capacity-related demand on the system). Label as "System C" the new total cost of the system designed by the planning model to deal with the AES demands. We know that the cost of System C is higher than that of System A (as the AES customers represent new capacity demands). The difference between Systems C and A represents the cost to provide capacity to AES customers.

One way to charge AES customers would be simply to charge them in aggregate (System C minus System A), but this is not the way Section 6w is written. Instead, since all customers must pay the same capacity charge, we know that the difference between C and B (System C minus System B) represents all of the capacity charges on the system.

The SRM charge (System C-System B) can simply be split across all of the capacity demands of both the AES and bundled service customers on a per kW of peak day demand, or on whatever drivers the planning models determine require capacity.

Q24. Your example appears to show that the capacity costs that the Section 6w legislation seeks are not found by looking at division of the costs of particular embedded assets. Is this right?

A24. Yes. Not only does the methodology in my example avoid arguing over what is really a capacity-related cost and what is not, it is particularly straightforward to implement. All that such a method requires is one additional run of the planning model software that the utilities already use. Once DTE has adjusted its planning models to increase its reserve margins to include the expected AES demands (as they would appear to have to do in any case under the legislation) the only additional run is one to set the reserve margin to zero. The difference in total costs in these two runs is the capacity cost of the all loads.

Q25. Has DTE performed such a modeling of prospective system peak capacity requirements that would apply to all customers (their own and retail choice)?

A25. In its interrogatory responses, DTE denied that they have carried out any such alternative planning process in advance of the implementation of Section 6w.[14] To the extent this is true; it would seem to be at odds with the way in which the legislation asks for a "cost effective, reasonable and prudent" SRM.

Q26. What has DTE done instead?

A26. DTE has proposed an alternative charging methodology where it divides the embedded cost of service of its entire system, including its purchased and interchange costs, between "capacity-related" and "non-capacity related." Fuel costs, for example, are not capacity related and depreciated capital costs are deemed capacity-related.

Q27. Do you have any concerns with DTE's approach?

A27. Yes. DTE's approach is not a forward-looking, economically efficient method, nor does it answer the question that the Michigan Legislature has put to the Commission: to quantify the cost of providing capacity to Michigan bundled service and AES customers. DTE's method misunderstands what *capacity* the legislation appears to be after: the incremental facilities needed to meet the projected coincident peak load as opposed to those that only provide energy (which the AES customers do not demand and cannot reasonably be charged).

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[14] DTE Responses to CNEDE-1.4, 1.6, attached as Exhibit CNE-1 (JDM-1).

A planning model, however, of the type that DTE already uses, determines the answer to the relevant question without any definitional ambiguity at all. If we design a system to meet the energy needs alone of all of DTE's Michigan ratepayers at least cost, and then redesign the system to meet both energy and capacity needs, then the difference in costs between the two models is the SRM capacity cost. Then, armed with the capacity requirements of both bundled service and AES customers, we can calculate a uniform price across classes per kilowatt of capacity.

Q28. What do you recommend?

A28. I recommend that, going forward, the Commission require DTE to perform and present a planning model calculation consistent with my above testimony when seeking approval of future SRM capacity charges. As DTE did not offer such a planning model computation so far, I resort to another method, discussed below, based on the data that DTE provided.

Q29. Recognizing the planning model data deficiency, is it possible to use DTE's embedded costs presented in this case to establish a reasonable SRM capacity charge for DTE?

A29. While I conclude that it would be better to employ DTE's planning software to simulate the distinction between *energy* and *capacity* costs in order to deal with potential AES load, I think the practical answer is: yes. A first step in assessing the reasonableness of DTE's computation is whether a reasonable re-statement of embedded costs calls the Company's computations into question.

As I have seen elsewhere, Michigan is an “embedded cost” state, regarding its cost recovery and allocation practices, and I can use embedded cost methods with DTE’s data to compute a reasonable SRM charge with such qualifications. In other words, there is nothing irretrievably wrong with using embedded costs—such costs reflect the property of DTE and are of course useful as the basis for its rates and charges. But the SRM is a particular charge with a particular purpose, and how to employ the embedded costs of DTE is of great importance. There is a proper way to use DTE’s embedded costs to help to structure a reasonable SRM that is cost effective, reasonable and prudent. But not the way DTE proposed.

Q30. You seem to be heavily qualifying the use of embedded costs for the purpose of making SRM computations. Why is that?

A30. I am indeed making such a qualification. Part of my answer has to do with the difference between the perspectives of accountants and economists. The other has to do with the methods that utilities like DTE employ to project resource adequacy.

On the question of accounting versus economics, the point is whether what we are after is a description of historical expenditures or the costs of meeting a particular requirement reasonably efficiently. Unlike most other business enterprises, the periodic charges that make up the rates for utilities like DTE reflect not the current value of its capital assets but rather an accounting allocation of the costs for capital investment decisions (and accompanying operating and fuel costs) already made. Depreciation charges drive those costs—determining when and how the costs of capital investments by utilities will be repaid by ratepayers. Economists have long recognized that such allocated charges "are merely a special method of writing history."[15]

To be sure, there is nothing wrong with the accounting of costs in the manner that reflects the US regulatory model's method of accounting for utility investments. I have written, just this year in the Electricity Journal, that the various institutions supporting that US regulatory model, including accounting, administration and the Constitutional protections of property that those institutions support, are a "national treasure" when it comes to faithfully tracking and preserving the property values that investors place in service to the public through utilities like DTE.[16] But that does not mean that those methods of accounting targeted at preserving the value of the property of utilities like DTE are automatically useful in computing a planning-based and market-based charge like the SRM.

Q31. **You said that Michigan is an "embedded cost" jurisdiction. How so?**

A31. I refer to the distinction between embedded-cost allocation for ratemaking and marginal-cost pricing. It is a distinction between the procedures for making regulated rates that target both economic efficiency and credit-sustaining revenues for investor-owned utilities like DTE.

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15 Bell, C.S., "Elementary Economics and Depreciation Accounting," *The American Economic Review*, Vol. 50, no. 1. (March 1960), p. 154.

16 Makholm, J.D., "Response to 'On the Radicality of New York's Reforming the Energy Vision' by Ross Astoria," *The Electricity Journal*, 30 (2017) 30-31.

For example, marginal-cost pricing had been known to economists since the 1930s.[17] Other countries, particularly France and the UK, instituted marginal cost pricing for their state-owned utilities beginning in the mid-1950s.[18] But only public opinion could drive US regulators to study the problem. Public opinion followed when inflation, OPEC-driven oil prices and the seeming exhaustion of scale economies in the electric utility industry after the 1970s with the sharply-rising consumer electricity prices of the era.

The resulting pressure of public opinion brought about two changes for America's electric utilities: (1) a focus on "marginal cost pricing" and (2) restructuring to promote competitive power generating markets. My late colleague at NERA, Alfred Kahn, then Chairman of the New York Public Service Commission, had just written his timely book on the subject.[19] Led by Wisconsin and New York, and reacting to the increased costs of the era, regulators and state legislators began to target marginal cost as the basis for more efficient electric utility ratemaking.[20] Indeed, partly because of Professor Kahn's association with NERA, and partly because of NERA's history as a firm of economists, we were prominent in promoting marginal-cost pricing in the 1970s onward—as evidenced by the NARUC Electricity Utility Cost Allocation Manual's reference to

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17 Hotelling, H, "The General Welfare in Relation to Problems of Taxation and of Railway and Utility Rates," *Econometrica*, 6 (1938), pp. 242-269; Bonbright, J.C., "Major Controversies as to the Criteria of Reasonable Public Utility Rates," *American Economic Review, Papers and Proceedings*, Vol. 30, No. 5 (1941). p. 385.

18 See Phillips, *The Regulation of Public Utilities*, p. 442 and pp. 470-471 (note 20).

19 Kahn, A.E., *The Economics of Regulation: Principles and Institutions* (Two Volumes), John Wiley & Sons, New York (1971).

20 In 1974, the Wisconsin Public Service Commission, under Chairman Richard Cudahy, opened a general investigation into the application of marginal cost pricing for the electric utilities in that state in a case involving Madison Gas and Electric Company (see: Cudahy, R.D., "Rate Redesign Today: The Aftermath of *Madison Gas*," *Public Utilities Fortnightly*, May 20, 1976, pp. 15-19). This was one year before New York opened a similar marginal cost pricing investigation, driven by Chairman Kahn.

NERA source materials on marginal cost pricing procedures.[21] Mr. Lacey refers to that NARUC manual as the source of some of his computations leading to DTE's recommended SRM.[22]

Not all jurisdictions, however, adopted the kind of marginal-cost-based ratemaking that began in New York and Wisconsin. Michigan, for example, continues to use embedded-cost methods as the basis for its cost of service studies—using various methods within an embedded costing framework to achieve efficiency goals. Mr. Brian Welke of the MPSC explained the essential differences between accounting-based (embedded) cost studies and marginal cost methods in a 2010 presentation as part of the Energy Regulatory Partnership Program.[23]

Q32. What do you conclude regarding DTE's calculation using such embedded costs?

A32. DTE's computations result in an SRM capacity charge of $436 per MW-day, I conclude that both the method and result are unreasonable.

Q33. Why is that?

A33. DTE's method is a simple re-statement of its traditional revenue requirement minus non-capacity related expenses—per MW-day. There is no planning element to DTE's computations nor is there any gauge by which to judge the reasonableness of $436 per MW-day by reference to any objective standard of the cost of capacity in the market. It is

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[21] The NARUC manual refers to NERA's 1977 "A Framework for Marginal Cost-Based Time-Differentiated Pricing in the United States" in Appendix 9A p. 120.

[22] Lacey testimony, p. TWL-7.

[23] Welke, B., "Cost of Service in Michigan," Energy Regulatory Partnership Program, September 2010. http://pubs.naruc.org/pub/53788719-2354-D714-5100-05E7E18ED721.

simply a figure by which AES suppliers would be charged a *pro rata* share of DTE's historical revenue requirement net of what it lists as non-capacity-related expenses.

There is nothing forward-looking, planning-based, or market-based about DTE's proposed SRM capacity charge of $436 per MW-day. It is a number that reflects only the embedded cost of service of its production fleet rate base. It is a "special method of writing history" regarding when and how DTE added to that fleet over time that tells us a lot about where the Company's property is and what compensation it expects over time. In particular, current excesses or deficits in supplying future needs do not affect this allocation at all.

Q34. Is there a way to adjust DTE's computations that you summarized above using recognized embedded cost methods to derive a reasonable SRM charge?

A34. Yes. Although, as I said at the outset of my testimony, it would be better and more reflective of the incremental cost of providing capacity-only SRM service to AES providers, there are embedded cost allocation procedures that are suitable to make such a reasonable adjustment.

Q35. What are they?

A35. The NARUC manual used by Mr. Lacey devotes its Chapter 4 to discussing embedded cost methods for allocating production costs—devoting the largest part of that chapter to distinguishing between "Peak Demand Methods" and "Energy Weighting Methods." Mr. Lacey uses a peak demand method, which the NARUC manual describes as comprising the following features: "…all production plant costs are classified as demand-related …

these costs are allocated among the rate classes on factors that measure the class contribution to the system peak."[24] But such features assume that all rate classes place both energy and capacity demands on the system. That assumption does not hold for AES customers: they have no energy demands—only capacity.

The distinction between energy and other demands on the system is what the Energy Weighting Methods in the NARUC manual are for. As the manual states:

> There is evidence that energy loads are a major determinant of production plant costs. Thus, cost of service analysis may incorporate energy weighting into the treatment of production plant costs. One way to incorporate an energy weighting is to classify part of the utility's production plant costs as energy-related and to allocate those costs to classes on the basis of class energy consumption.[25]

With respect to production plant expenses, AES customers are a class that has no energy consumption. In that respect the Energy Weighting Methods are "tailor-made" for the SRM charge. Such a charge would apply to AES customers as that class's only production-related charge and to full-service DTE customers as one element of their full-service revenue requirement, including a charge for their energy loads that do not apply to the AES customers.

Q36. Which of the NARUC particular Energy Weighting Methods do you recommend using to adjust DTE's computations?

A36. I recommend the first of the various methods presented in the manual, called the "Average and Excess" method. The method is familiar and widely discussed as one of

[24] NARUC Manual, p. 41.
[25] NARUC Manual. P. 49.

the principal methods of using embedded costs to allocate production cost for electric utilities. Professor James Bonbright describes the "average and excess-demand" method as follows:

> Here, the assumed cost of that portion of the company's plant capacity which would be needed even if all consumers were taking their power at 100 percent load factor is apportioned among customers in proportion to their average loads—that is, in proportion to their kilowatt-hour consumption of energy during the time period in question.[26]

The average and excess method permits the allocation of production plant costs to average loads—using only the "excess" to allocate based on the difference between average loads (that do not apply to AES customers) and maximum demand (that does). The result is that AES customers pay only a pro rata share of the latter. The data requirements needed to perform the allocation objectively are straightforward—average and peak-load measures for each class of service.

The other methods illustrated in the NARUC manual (Equivalent Peaker Method, Base and Peak Method, Judgmental Energy Weightings) require system planning data, assume that all classes consume energy, or are in some sense subjective.

Q37. Please describe your adjustment to DTE's SRM capacity charge using the average and excess method.

A37. First, I derived the system load factor by dividing average demand by coincident peak demand. Then, I calculated the percentage of costs to be allocated to capacity, or the excess demand allocation factor, which is equal to one minus the system load factor.

[26] Bonbright, J.C., *Principles of Public Utility Rates*, Columbia University Press, New York (1961), pp. 352-53.

Finally, I used the excess demand allocation factor to re-allocate the line item expenses in DTE's cost of service study to capacity. The table below shows these calculations. I apply the derived Excess Demand Allocation Factor to DTE's cost of service study expenses to allocate those costs to capacity. Using the average and excess method, I calculate an SRM capacity charge of $224/MW-day. The second part of the table below illustrates this calculation as compared to DTE's proposed SRM capacity charge.

Table 1: Re-Calculation of DTE's Capacity Charge Using Average and Excess Method

	Amount
Average Demand (2016- 2017) (MW)[1]	4,761
CP Demand (2017-2018) (MW)[2]	9,840
System Load Factor (Average/CP)[3]	48%
Excess Demand (1 - Load Factor)[3]	52%

	Amount Allocated to Production ($, 000)[4] [a]	**Amount Allocated to Capacity for SRM Charge ($, 000)**[5] [b]	**Average and Excess Method Amount Allocated to Capacity ($, 000)** [c] = [a] * 51.62%[6]
Fuel Expenses	$1,208,552	$0	$0
Purchased & Interchanged Expenses	$193,779	$143,234	$73,932
O&M Expenses	$656,316	$620,898	$338,767
Depreciation Expenses	$302,043	$302,043	$155,904
Other Taxes	$141,456	$141,456	$73,015
Income Taxes	$160,075	$160,075	$82,625
Required Revenue Minus Expenses	$402,034	$402,034	$207,516
Energy Sales Revenue Net of Fuel Costs[7]	-	($43,949)	($43,949)
Total Allocated Amount	$3,064,254	$1,725,790	$887,810
2019- 2020 UCAP (MW)[8]		10,839	10,839
Capacity Charge ($/MW-day)		**$436**	**$224**

Notes:

1 Case U-18284, DTE Electric Company Application, Exhibit A-11, Schedule 1, page 3.

2 See Case No. U-18197, Electricity Supply Reliability Plan for Planning Years 2017 to 2021, April 21, 2017, p. 8, Table 4.

3 NARUC Manual, pp. 49-52.

4 See Response to ABDE-1, Case No. U-18014 Final Cost of Service Model, unless otherwise specified.

5 Derived from DTE's Response to ABDE-1, CNEDE-1.2 and CNEDE-1.3, unless otherwise specified. Uses DTE's allocation of specific items to non-capacity in Exhibit A-14 in order to derive the costs implicitly included as capacity for each line item included in its Final Cost of Service Model in Case No. U-18014.

6 Since no fuel expenses should be allocated to capacity, the average and excess amount allocated to capacity for Purchased and Interchanged Expenses is calculated by multiplying 51.62% by the value in Column [b] instead of Column [a] because the value in Column [b] does not include fuel expenses.

7 Since energy sales revenue net of projected fuel costs is subtracted from the production revenue requirement in order to get the capacity related revenue requirement in DTE's original calculation, it is also subtracted in Column [c] under the average and excess method.

8 See Case No. U-18197, DTE's Electric Supply Reliability Plan for Planning Years 2017 to 2021, April 21, 2017, p. 8, Table 4.

Q38. Is there a way to check whether this SRM computation is reasonable?

A38. Yes. A check on the reasonableness of the SRM result lies in the Cost of New Entry ("CONE"), as well as a market price in the form of Consumers recent RFP for demand-side ZRCs.

Q39. What is CONE?

A39. The CONE value consists of the capital, operating, financial and other costs of acquiring a new generation resource within the Transmission Provider Region for any designated Local Resource Zone (LRZ).[27] MISO uses the CONE in a variety of processes; however, it is primarily used in Planning Resource Auctions (PRAs) when there is an insufficient amount of ZRC offers, and in Capacity Deficiency Charges levied upon Load Serving Entities (LSEs). MISO calculates the CONE for each of the ten LRZs in the region, and compares its calculations with those of Potomac Economics, the Independent Market Monitor (IMM) for the MISO region that also calculates the CONE. MISO recalculates the CONE each year and files the annual calculation with the FERC, who then approves or rejects the value.

MISO is required to file its annual CONE values to FERC for approval as a result of a series of orders issued by FERC. FERC first issued an "Order on Compliance Filing" on April 21, 2010.[28] Another FERC order, issued on June 8, 2010, directed MISO to develop a plan to incorporate locational capacity market mechanisms into the Resource Adequacy Plan in order to provide incentives for Market Participants (MPs) to obtain a

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[27] MISO, FERC Electric Tariff Module A, § 1.C.
[28] MISO, 131 FERC ¶ 61,057, P.19.

sufficient supply of local resources.[29] Both of these orders required MISO to calculate the CONE for the LRZs. In response to both orders, MISO filed its proposed revisions on July 20, 2011, which FERC accepted on March 15, 2016.[30] Starting on September 3, 2013, MISO began to submit its annual CONE calculation for each individual LRZ.[31] The current CONE values for MISO appear in the table below. Local Resource Zone 7 comprises Michigan's Lower Peninsula with a CONE of $94,900/MW-year or $260/MW-day.

Table 3: MISO CONE Values ($/MW/yr.) for Local Resource Zones for Planning Year 2017-2018[32]

Local Resource Zone 1	$ 94,290
Local Resource Zone 2	$ 95,230
Local Resource Zone 3	$ 93,190
Local Resource Zone 4	$ 94,690
Local Resource Zone 5	$ 96,550
Local Resource Zone 6	$ 94,350
Local Resource Zone 7	$ 94,900
Local Resource Zone 8	$ 90,500
Local Resource Zone 9	$ 91,770
Local Resource Zone 10	$ 89,840

Q40. Do these figures represent the full cost of capacity resources in the market, including both capital and operating (and fuel) costs?

A40. Yes. A description of the elements of contributing to CONE appears below:

> 50/50 debt to equity ratio; a 20-year project life and loan term; a 6.20 percent debt interest rate; a 2.0 percent Operation and Maintenance escalation factor; a

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29 MISO, 131 FERC ¶ 61,228, P.24.

30 MISO, Filing of Midcontinent Independent System Operator, Inc. Regarding LRZ CONE Calculation, September 23, 2016.

31 MISO, Annual CONE Filing Letter, § 1. (2016).

32 MISO, Filing of Midcontinent Independent System Operator, Inc. Regarding LRZ CONE Calculation, September 23, 2016, Attachment B.

> 2.4 percent GDP deflator; a 42 percent combined effective federal and state tax rate; property tax and insurance costs of 1.5 percent of the capital costs; a calculated weighted average cost of capital of 7.79 percent; and a 12 percent after tax internal rate of return on equity. [33]

This is a reasonable description of both capital and operating costs.

Q41. Why is CONE a reasonable check on SRM computations based on the use of embedded costs?

A41. CONE reflects a reasonable forward-looking estimate, accepted by the FERC, for the cost of entry of new capacity resources in various regions for which it oversees the operation of energy and capacity markets. CONE should be the absolute cap on any SRM charge because it includes all capacity costs, as well as non-capacity costs.

Q42. You mentioned Consumers' auction for ZRCs (Zonal Revenue Credits) as a way of checking your proposed calculation of a reasonable SRM charge for. Please explain.

A42. MISO ensures that there are sufficient resources to meet demand in its various zones through its Resource Adequacy Requirements (RAR), using an auction to solicit offers from the power markets since 2013.[34] The ZRCs (credits for owning resources that count toward MISO resource adequacy requirements) secured in the auction by market participants become the price paid to all resources that clear the auction.

Consumers recently issued an RFP for ZRCs for the demand side. Only those at or below $164/MWD were picked, meaning that there were capacity related resources available at

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[33] MISO, Annual CONE Filing Letter, § III.A.

[34] A reasonable description of MISO's policies regarding its auction for ZRCs is what follows: http://archive.iamu.org/default%20page%20links/MISO/MISO%20Market%20Report%2010-12-12.pdf

that price.[35] While DTE did not issue this RFP, the price reasonably represents a recent value in the Zone 7 market for ZRCs to which we can compare.

Q43. What do you conclude with this benchmark for the cost of capacity on DTE's system?

A43. I conclude that DTE's proposal of $436/MW-day for SRM service is not reasonable.

III. Other SRM Issues

Q44. What is the purpose of this section of your testimony?

A44. In this section, I discuss two other issues that appear in the DTE testimony: (1) the Company's proposed 30-year term of service, if an AES customer requires the SRM service; and (2) the Company's proposal that AES customers return to utility service as interruptible customers if sufficient capacity is unavailable to serve them.

Q45. What is your understanding of DTE's proposed 30 year term for SRM service to AES customers?

A45. DTE requests that any AES customer that returns to the utility for either bundled or simply SRM capacity service remain a utility capacity customer for 30 years. As Mr. Stanczak states:

> Once an Electric Choice customer returns for either bundled or capacity only service, they must stay with the Company for a 30-year period. This will

[35] Case No. U-18382, In the matter of the application of Consumers Energy Company for approval of long-term power purchase agreements. Testimony of David F. Ronk, Jr., page 10.

> provide the needed assurance that the costs associated with any asset built to support the required capacity can be recovered from the customer.[36]

Q46. Is what Mr. Stanczak describes reasonable?

A46. I conclude that it is not—for the reason that it assumes that DTE will be building or otherwise acquiring new rate base for any such customer. I think that the electricity market in Michigan, in MISO, and in electricity markets more broadly point to greater, and not less, competition in the supply of electric power services. DTE's proposal pre-supposes that it will add power plants, rather than purchase power and capacity in the markets for those services, and I do not think that the Company has made any support for its pre-supposition.

In my opinion, Mr. Stanczak discusses buying or building capacity without dealing with the great differences in risk associated with one or the other. For example, he states: "…once a Choice customer notifies the Company of their desire to utilize Company generation capacity, the Company will do everything prudent to secure the required capacity, up to and including building a new power plant."[37] That explanation would seem to minimize one of the more important reasons for pursuing competition in providing electric power—to transfer the risk of building major capital assets to the market (and away from traditional regulatory approval and ratepayers). I do not think that DTE has justified that the prospect of AES customers needing SRM service will prompt it to build a new 30-year power plant.

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36 Stanczak, pp. 15-16.
37 Stanczak, p. DMS-16.

Q47. What about wider evidence than simply Michigan's MISO zones regarding competitive power markets?

A47. Evidence from Michigan's region and around the world shows that, except for the immediate aftermath of the California energy crisis, there has been a steady worldwide move toward embracing and extending retail access or energy services provided by regulated distribution utilities and thereby supporting the competitive provision of electricity services. In my opinion, it is unreasonable to believe, without some demonstrated support, that DTE will be able to provide the lowest cost to its consumers by building its own long-lifetime (i.e., 30-year) power plants—as it did before electricity competition began as an institution throughout much of the United States and Canada.

Q48. Can you briefly describe that US and Canadian experience in competitive power markets?

A48. Yes. Fifteen states have competitive power markets with retail electricity access, including among them Connecticut, Delaware, Massachusetts, New Jersey, New York, and Texas. Nine additional states were deregulated in the past. Texas was one of the first states to implement full retail access in 1999.[38] After the California energy crisis in the early 2000s, several states stopped or paused energy deregulation, including Arizona, Arkansas, California, Oklahoma, Oregon, and Virginia. California restarted full retail access for non-residential consumers in 2011. Nevada began electricity deregulation in

[38] Texas Power to Choose, FAQs, http://www.powertochoose.org/en-us/Content/Resource/FAQ.

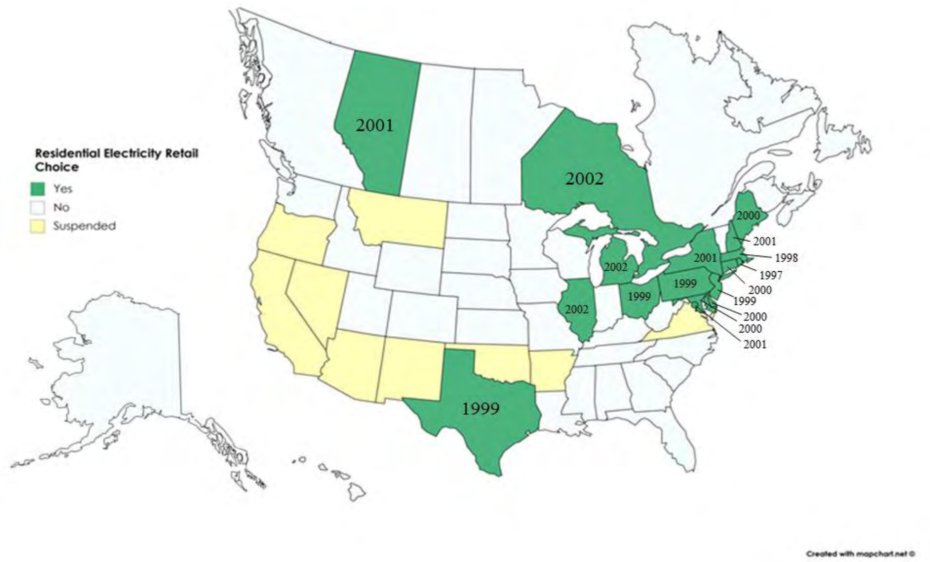
the late 1990s, stopped the process after the California energy crisis, but started again—passing a state-wide referendum in November 2016.[39]

In Canada, Alberta and Ontario support competitive power markets with retail access. Alberta opened the electricity market to retailers with the Electric Utilities Act of 1995. Residential consumers are free to choose an energy retailer or a regulated default service rate (40 percent make that choice). Ontario initially deregulated the electricity market in 2002. While Ontario does currently allow residential customers to choose an electricity provider, the government offers a regulated price plan. Further regulations in 2010-2012 effectively limited residential retail electricity choice, but residential retail supply service remains legal.[40] The competitive retail electricity choice states that I mentioned above are shown below:[41]

[39] Davis, K., "State of Deregulation: N.M., Nev. Looking to return their deregulation packages," Electric Light & Power, July 1, 2001, http://www.elp.com/articles/print/volume-79/issue-7/departments/state-of-deregulation-nm-nev-looking-to-return-their-deregulation-packages.html.

[40] Direct Energy, "Energy Deregulation in the United States and Canada," https://business.directenergy.com/what-is-deregulation.

[41] Map data was compiled from the following sources: Morey, J., and Laurence, K., "Retail Choice in Electricity: What Have We Learned in 20 Years?" Electric Markets Research Foundation, February 2, 2016; Direct Energy, "Energy Deregulation in the United States and Canada," https://business.directenergy.com/what-is-deregulation#deregmarket; Alberta Electric System Operator, "Guide to understanding Alberta's electricity market," https://www.aeso.ca/aeso/training/guide-to-understanding-albertas-electricity-market/; Canadian Electricity Association, "Industry Overview," http://www.electricity.ca/industry-issues/electricity-in-canada/industry-overview.php.



Q49. How does this bear on DTE's 30-year proposal?

A49. It is hard to reconcile DTE's presumption that it will be building new 30-year power plants to support the kind of competitive power customer base represented by those who choose AES service. The trend, at least in the wider electricity market outside of Michigan, is in the other direction—with power markets and the growth of the institutions (including MISO) that support them.

Q50. What about DTE's proposal to make an AES customer's election to take bundled or capacity only service from the utility irrevocable?

A50. DTE ties its discussion of this issue to an assumption that the capacity needed to support the SRM will be new investment, not purchases in the capacity market. For example:

> [T]he Company will do everything prudent to secure the required capacity, up to and including building a new power plant…Without a long-term commitment by the returning Choice customer, it would be imprudent for the

> Company to make a long-term commitment for the incremental capacity required to serve the returning customer.[42]

I do not think it reasonable for DTE to consider the prospect of AES customers actually using SRM service to lead in such a seemingly automatic way to new regulated power plant investments—built in the traditional fashion with the risk falling on ratepayers to support the useful life of such a plant. As it has done for other capacity, DTE can minimize such risk by paying the market price for capacity over a term that squares the risk that it bears for serving its respective customers class loads.

Nothing that DTE has offered in this proceeding, in my opinion, justifies using the prospect for AES customers utilizing SRM service—despite their AES suppliers' showing under Section 6w(6) that they have adequate resources—as the trigger for making new 30-year investments on their behalf.

Q51. Does DTE tie its irrevocable 30-year requirement to building new capacity?

A51. Effectively, yes. DTE's proposed term for customers utilizing the utility for capacity service (and thus paying the SRM capacity charge) presupposes building new capacity (as reflected in the quote above from Mr. Stanczak's testimony). That is, reliance on new capacity construction ties the SRM capacity charge to the amortization of new rate base over whatever term DTE decides—10, 20, or 30 years. However, DTE provides no justification for such rate based investment as opposed to purchases of incremental capacity in the market.

[42] Stanczak, p. DMS-16.

Q52. What comments do you have regarding the proposal by DTE that AES customers return to utility service as interruptible customers if sufficient capacity is unavailable to serve them?

A52. Mr. Stanczak also proposes an interruptible service for AES customers in situations where it sees a potential shortfall of capacity. He states:

> …notwithstanding our best efforts, we may not be able to procure the required capacity to serve all customers if a significant amount of Choice [i.e., AES] load returns to DTE…. [A] reasonable and appropriate way to deal with such a situation is for the Company to charge a reduced interruptible capacity charge for [AES] load that is not supported by either Company owned or purchased capacity.[43]

I do not agree with DTE's proposal.

Q53. Why not?

A53. I have two reasons.

First, there is currently a queue behind the 10 percent cap in AES service. In the event that an AES customer returns to the utility, particularly in the short term, there are evidently customers waiting to leave utility service for AES service. I present a chart below showing the queue for the two major electric utilities in Michigan, including DTE.[44]

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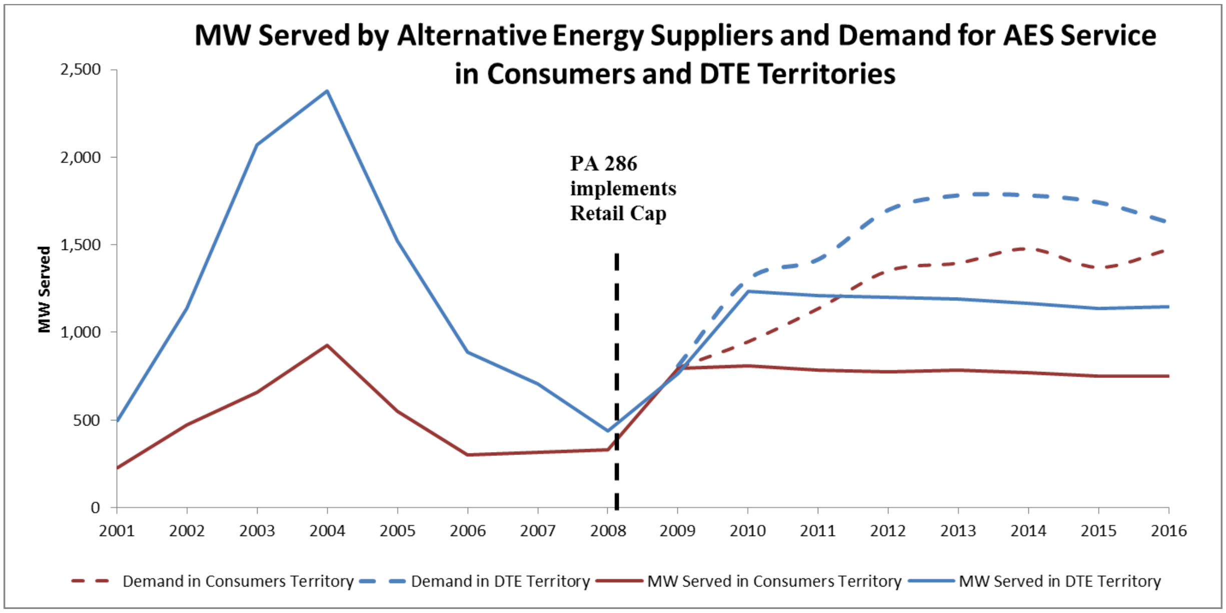
[43] Stanczak, p. DMS-10. Mr. Stanczak refers to a new combined cycle combustion gas turbine as an example of such a 30-year plant. See his answer to data request: CNEDE-1.7, attached as Exhibit CNE-2 (JDM-2).

[44] Source: Status of Electric Competition in Michigan reports. For 2008 to 2016, I calculate demand for AES service by adding the amount of MWh in the queue to the amount of AES load served. I convert MWh in the queue to MW for each year by dividing by 8,760 hours.



Second, and more importantly, this Section 6w proceeding is designed to structure a charge to remedy what the legislature perceived as a looming problem with uncompensated capacity service for AES customers that may, either by choice or in an unanticipated fashion, rely on DTE for peak capacity service. To the extent that the Commission structures what it considers a reasonable SRM charge, then those customers that must return to pay that charge for the planning year beginning June 1, 2018 or any of the subsequent 3 planning years must pay the applicable charge for each of those planning years.[45] That is, the SRM charge countervails the lower priority of service that DTE seems to wish to assign to AES customers. As DTE states:

> The Company can maintain reliability by bringing customers back to firm service if/as capacity becomes available. If capacity is not available then current Electricity Choice [AES] customers returning to the Company for

[45] Section 6w(8)b(i)

> capacity, will be placed on interruptible service and pay the Company a capacity charge consistent with that interruptible service…[46]

Because Section 6w requires that Michigan utilities "ensure that the resulting capacity charge does not differ for full service load and alternative electricity supplier [AES] load,"[47] DTE's specification of a lesser priority for the payment of the same capacity charge borne by firm service customers is unjustifiably discriminatory for AES customers.

In my opinion, consistent with how I interpret those economic features evident in the Section 6w legislation, the service covered by the SRM should apply with equal priority to all who pay for it. Such would seem to be a critical element of the legislation—to ensure that customers who pay the SRM capacity charge receive the service for which they pay that price to obtain. A reduced rate for interruptible service to be levied only on AES customers—consistent with what I called the only difference in Scenarios A and C in the illustrative example I have earlier in my testimony—seems to me to be inconsistent with Section 6w—which makes no provision for different priorities of access to capacity for either AES or utility customers.

Q54. Does this conclude your testimony at this time?

A54. Yes.

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[46] Wojtowicz testimony, p. APW–11.

[47] Section 6w(3).

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Dr. Makholm specializes on the issues of valuation, damages and proper regulated pricing in hard commodity markets and energy industries. With respect to hard commodities (including mining, processing, transport and sale in international markets), he assess production and lease contracts, economic transport costs, and values in local and international markets according to the accepted economic principles of vertical relationships in complex, multi-stage hard commodity production markets. Another of Dr. Makholm's areal of specialty involves the privatization, regulation and deregulation of energy and transportation industries—those that operate networks (such as oil and gas pipelines, electricity transmission and gas distribution systems, telecommunications and water utility systems, railroads and toll roads) and those operating infrastructure business at specific sites, such as oil refineries, electricity generation plants, gas treatment plants, commodity mines, sewage treatment plants and airports. These issues include the broad categories of efficient pricing, market definition and the components of reasonable regulatory and contracting practices. On such issues among others, Dr. Makholm has prepared expert testimony, reports and statements, and has appeared as an expert witness in court proceedings, arbitral tribunals, regulatory bodies and Parliamentary panels on more than 250 occasions.

Dr. Makholm's clients in North America include privately held oil, gas and utility corporations, public corporations and government agencies. He has represented dozens of gas and electric distribution utilities, as well as both intrastate and interstate oil and gas pipeline companies and oil, gas and electricity producers. Dr. Makholm has also worked with many leading law firms engaged in issues pertaining to the local and interstate regulation of energy utilities.

Internationally, Dr. Makholm has directed an extensive number of projects in the mining, utility and transportation businesses in 20 countries on six continents. These projects have involved work for investor-owned and regulated business as well as for governments and the World Bank. These projects have included advance pricing and regulatory work prior to major gas, railroad and toll highway privatizations (Poland, Argentina, Bolivia, Mexico, Chile and Australia), gas industry restructuring and/or pricing studies (Canada, China, Spain, Morocco, Mexico and the United Kingdom), utility mergers and market power analyses (New Zealand), gas development and and/or contract and financing studies (Tanzania, Egypt, Israel and Peru), regulatory studies (Chile, Argentina), oil pipeline transport financing and regulation (Russia), and valuating in hard commodity mining (Russia, Peru, Colombia, New Zealand). As part of this work, Dr. Makholm has prepared reports, drafted regulations and conducted training sessions for many government, industry and regulatory personnel.

Dr. Makholm has published many papers in various peer-reviewed and editor-reviewed publications (*Economics of Energy & Environmental Policy*, *Public Utilities Fortnightly*, *Natural Gas and Electricity*, *The Electricity Journal*, *The Energy Law Journal, and Competition and Regulation in Network Industries*)—involving a wide range of subjects pertaining to his research work. He is a frequent speaker in the U.S., Europe and elsewhere at conferences and seminars addressing market, pricing and regulatory issues for the energy, commodity and transportation sectors. His latest book, *The Political Economy of Pipelines: A Century of Comparative Institutional Development*, was published by the University of Chicago Press in 2012.

EDUCATION

UNIVERSITY OF WISCONSIN-MADISON,
MADISON, WISCONSIN
Ph.D., Economics, 1986
Dissertation: Sources of Total Factor Productivity in the Electric Utility Industry
M.A., Economics, 1985

BROWN UNIVERSITY
PROVIDENCE, RHODE ISLAND
Graduate Study, 1980-1981

UNIVERSITY OF WISCONSIN-MILWAUKEE
MILWAUKEE, WISCONSIN
M.A., Economics, 1980
B.A., Economics, 1978

EMPLOYMENT

1996-present	Senior Vice President/Managing Director. National Economic Research Associates, Inc., (NERA) Boston, Massachusetts.
1986-1996	Vice President/Senior Consultant. National Economic Research Associates, Inc., (NERA) Boston, Massachusetts.
1987-1989	Adjunct Professor. College of Business Administration, Northeastern University, Boston, Massachusetts
1984-1986	Consulting Economist. National Economic Research Associates, Inc., (NERA) Madison, Wisconsin.
1983-1984	Consulting Economist. Madison Consulting Group, Madison, Wisconsin.
1981-1983	Staff Economist. Associated Utility Services, Inc., Moorestown, New Jersey.

RECENT TESTIMONY (SINCE 2000)

Before the International Court of Arbitration, Case No. 1976/CA/ASM, Drummond Coal Mining LLC (DCM), et al, Respondents/Counterclaimants, vs. Ferrocarriles del Norte de Colombia S.A.., Claimant/Counter-Respondent, Expert Report, 20 June 2017. Subject: Market values of mining export losses due to imposed constraints on capacity.

Before the National Energy Board, Expert Report and Reply Testimony on behalf of Plains Midstream Canada ULC. Hearing Order RH-002-2016, May 15, 2017. Subject: Proper cost allocation for liquid fuel pipeline tariffs.

Before the National Energy Board, Expert Report and Direct Testimony on behalf of Plains Midstream Canada ULC. Hearing Order RH-002-2016, November 2016. Subject: Proper cost allocation for liquid fuel pipeline tariffs.

Before the Supreme Court of the State of New York, County of New York, Expert Testimony on behalf of plaintiffs in: S.A. de Obras y Servicios, Copasa and Cointer Chile, S.S. and Azvi Chile, S.A. Agencia en Chile, Plaintiffs v. The Bank of Nova Scotia and Scotiabank Capital, IAS Part 49, Index No. 651649/2013 and 651555/2012. August 10, 2016, Subject: Value of P3 toll road enterprise in Chile.

Before the National Energy Board, Expert Testimony on behalf of FortisBC Energy Inc., Hearing Order Number GH-003-2015, March, 2016. Subject: Tolling for pipeline extensions

Before the Superior Court of the State of Delaware in and for New Castle County, Expert Report on behalf of Deere & Company, in C.A. No. N13C-07-330 MMJ CCLD. December 2, 2015. Subject: Value of Power Purchase Agreements in the wind power industry.

Before the Superior Court of the State of California for the County of Los Angeles in the Matter of GAF Materials Corporation v. Paramount Petroleum Corporation, Opinion given September 3, 2015. Case No: BC 481673. Subject: Oil price indexing to set asphalt prices.

Before the United States District Court for the Northern District of Oklahoma, Expert Report on behalf of SFF-TIR, LLC, the Stuart Family Foundation (et al), Case No. 14-CV-369-TCK-FHM, June 30, 2015. Subject: Fair value of shares in a pipeline industry services firm.

Before the International Chamber of Commerce Expert Report on behalf of STP Energy Pte Ltd. Subject: Valuation of offshore oil and gas exploration permit, April 29, 2015.

Before the Régie de l'énergie, Written Evidence on behalf of Gaz Métro. Subject: Pricing of gas distribution system expansion, January 20, 2015

Before the Supreme Court of Western Australia, Filed Statement on behalf of North West Shelf Pty Ltd, Subject: Value and interpretation of gas swaps agreement, December 24, 2014.

Before the District Court of Tarrant County, Texas, 17th Judicial District, Expert Report of Jeff D. Makholm on behalf of OAO Gazprom, et al, Subject: Valuation of failed LNG import project, November 14, 2014.

Before the National Energy Board, Expert Report and Direct Testimony on behalf of MAS (Market Area Shippers Group), Hearing Order RH-001-2014, July 2014. Subject: Effectiveness of toll design//regime in settlement.

RECENT TESTIMONY (SINCE 2000 CONTINUED)

Before the National Energy Board, Expert Testimony on behalf of FortisBC Energy Inc., Hearing Order Number GH-001-2014, July 10, 2014. Subject: Tolling for pipeline extensions.

Before the National Energy Board, Expert Testimony on behalf of Alliance Pipeline, May 22, 2014. Subject: Restructuring services/tolls.

Before the Economic Regulation Authority of Western Australia on behalf of ATCO Gas Australia, March 2014. Subject: Cost accounting for gas pipeline regulation.

Before the 298th Judicial District Court of Dallas County, Texas, Expert Testimony on behalf of plaintiff in Energy Transfer Partners, L.P., and Energy Transfer Fuel, L.P. v. Enterprise Products Partners, L.P., Enbridge (US) Inc., and Enterprise Products Operating LLC, Cause No. 11-12667, February 2014. Subject: Assessment of causation and valuation of damages from lost crude oil pipeline opportunity.

Before the National Energy Board, Expert Testimony on behalf of Enbridge Gas Distribution Inc. and Union Gas limited, Hearing Order MH-001-2013, November 1, 2013. Subject: Tolling issues involving pipeline abandonment.

Before the National Energy Board, Expert Report and Direct Evidence on behalf of MAS (Market Area Shippers Group), Hearing Order RH-001-2013, July 26, 2013. Subject: Contract renewal provisions.

Before the 298th Judicial District Court of Dallas County, Texas, Supplemental Report on behalf of plaintiff in Energy Transfer Partners, L.P., and Energy Transfer Fuel, L.P. v. Enterprise Products Partners, L.P., Enbridge (US) Inc., and Enterprise Products Operating LLC, Cause No. 11-12667, July 24, 2013. Subject: Causation and damages in abandoned joint oil-pipeline venture

Before the 298th Judicial District Court of Dallas County, Texas, Rebuttal Expert Report on behalf of plaintiff in Energy Transfer Partners, L.P., and Energy Transfer Fuel, L.P. v. Enterprise Products Partners, L.P., Enbridge (US) Inc., and Enterprise Products Operating LLC, Cause No. 11-12667, March 2013. Subject: Causation and damages in abandoned joint oil-pipeline venture

Before the 298th Judicial District Court of Dallas County, Texas, Direct Expert Report on behalf of plaintiff in Energy Transfer Partners, L.P., and Energy Transfer Fuel, L.P. v. Enterprise Products Partners, L.P., Enbridge (US) Inc., and Enterprise Products Operating LLC, Cause No. 11-12667, January 2013. Subject: Causation and damages in abandoned joint oil-pipeline venture

Before the Alberta Public Utility Commission, Direct Testimony on behalf of ATCO Electric and ATCO Gas, Proceeding ID #2131, December 2012. Subject: Analysis of ATCO Electric's and ATCO Gas' capital tracker proposals

Before the American Arbitration Association, Expert Report with Dr. Victor P. Goldberg, Case No. AAA No. 16 132 Y 00502 11. December 17, 2012. Subject: Confidential Arbitration.

Before the National Energy Board, Written Evidence on behalf of FortisBC Energy Inc., Hearing Order GH-001-2012, May 29, 2012. Subject: Tariff treatment for pipeline extensions to new Canadian gas production regions.

Before the National Energy Board, Expert Report and Direct Testimony on behalf of Market Area Shippers Group, Hearing Order RH-003-2011, March 2012. Subject: Assessment of TransCanada's omnibus restructuring proposal and commentary on Market Area Shippers Group's alternative solution.

RECENT TESTIMONY (SINCE 2000 CONTINUED)

Before the Alberta Public Utility Commission (with Agustin J. Ros). Reply Expert Report. Application No. 1606029, AUC Proceeding 566. February 22, 2012. Subject: Update to TFP analysis and review of PBR plans for the Commission's performance-based regulation initiative.

Before the State Corporation Commission of the State of Kansas, Testimony on Behalf of Coffeyville Resources Refining & Marketing, LLC, Docket No. 12-MDAP-068-RTS. October 25, 2011. Subject: Reasonable ratemaking methodology.

Before the United States Federal Energy Regulatory Commission, Prepared Direct Testimony in Public Utilities Commission of Nevada and Sierra Pacific Power Company v Tuscarora Gas Transmission Company, Docket No. RP11-1823-000. October 17, 2011. Subject: Reasonable interstate gas pipeline tariff levels.

Before the Public Utilities Commission of Nevada, Pre-filed Rebuttal Testimony on behalf of Nevada Power Company and Sierra Pacific Power Company d/b/a NV Energy. Docket Nos. 11-03003, 11-03004 & 11-03005. August 3, 2011. Subject: Prudence of hedging practices.

Before the United States Federal Energy Regulatory Commission, Affidavit in Public Utilities Commission of Nevada and Sierra Pacific Power Company v Tuscarora Gas Transmission Company, Docket No. RP11-1823-000. February 28, 2011. Subject: Reasonable interstate gas pipeline tariff levels.

Before the Public Utilities Commission of Nevada, Prepared Direct on behalf of Nevada Power Company d/b/a NV Energy, 2011 Gas and Electric Deferred Energy Proceeding, Docket No. 11-03___. February 24, 2011. Subject: Prudence of hedging practices.

Before the Public Utilities Commission of Nevada, Prepared Direct on behalf of Sierra Pacific Power Company d/b/a NV Energy, 2011 Gas Deferred Energy Proceeding, Docket No. 11-03___. February 24, 2011. Subject: Prudence of gas hedging practices.

Before the Federal Energy Regulatory Commission and the State of Alaska Regulatory Commission, Prepared Direct Testimony on behalf of Trans Alaska Pipeline System. Docket No. IS09-348-004, *et al*. January 21, 2011. Subject: Prudence of capital rehabilitation costs.

Expert report filed before the Alberta Public Utility Commission (with Agustin J. Ros). Application No. 1606029, AUC Proceeding 566. December 30, 2010. Subject: Total factor productivity study for use in the Commission's performance-based regulation initiative.

Before the Commonwealth of Kentucky, Edmonson Circuit Court. Opinion on behalf of plaintiff in Honeycutt vs. Atmos Energy Corporation. Docket No. 09-CI-00198 and 10-CI-00040. September 10, 2010. Subject: Valuation of natural gas for royalty computations.

Before the Régie de l'Energie, Direct Testimony on behalf of Hydro-Québec TransÉnergie. Demande R-3738-2010. August 2, 2010. Subject: Economic analysis of issues related to the regulatory policies for network upgrades.

Before the Public Utilities Commission of Nevada, Pre-Filed Supplemental Direct Testimony on behalf of Nevada Power Company, Sierra Pacific Power Company d/b/a NV Energy (electric and gas departments), Docket No: 10-03003, 10-03004, 10-03005. May 5, 2010. Subject: Gas hedging.

Before the Arkansas Public Service Commission, Rebuttal Testimony on behalf of Entergy Arkansas, Inc., Docket No. 09-084-U. March 24, 2010. Subject: Justification of the operation of a multi-year formula rate plan.

RECENT TESTIMONY (SINCE 2000 CONTINUED)

Before the Public Utilities Commission of Nevada, Pre-Filed Direct on behalf of Nevada Power Company, Docket No. 10-03003. February 26, 2010. Subject: Prudence of gas purchase costs.

Before the New York State Public Service Commission, Rebuttal Testimony on behalf of Rochester Gas and Electric Corporation, Case 09-E--07717 Case 09-G-0718 and New York State Electric & Gas Corporation, Case 09-E-0715, Case 09-E-0716. February 12, 2010. Subject: Cost of equity capital.

Before the Public Utilities Commission of Nevada, Pre-Filed Direct Testimony on behalf of Sierra Pacific Power Company , Docket No. 09-09001. December 15, 2009. Subject: Gas hedging plan.

Before the Public Utilities Commission of Nevada, Pre-Filed Direct Testimony on behalf of Nevada Power Company , Docket No. 09-07003. December 15, 2009. Subject: Gas hedging plan.

Before the New York State Public Service Commission, Direct Testimony on behalf of Rochester Gas and Electric Corporation, Case 09-E--07717 Case 09-G-0718. September 17, 2009. Subject: Cost of capital and capital structure.

Before the New York State Public Service Commission, Direct Testimony on behalf of New York State Electric & Gas Corporation, Case 09-E-0715, Case 09-E-0716. September 17, 2009. Subject: Cost of capital and capital structure.

Before the Arkansas Public Service Commission, Direct Testimony on behalf of Entergy Arkansas, Inc., Docket No. 09-084-U. September 4, 2009. Subject: Justification of the operation of a multi-year formula rate plan.

Submission before the New Zealand Commerce Commission, on behalf of Orion New Zealand Limited, July 31, 2009. Subject: Theory and practice of price cap regulation.

Before the Hawaii Public Utilities Commission, Testimony on behalf of Hawaiian Electric Company Inc., Docket No. 2008-0083. July 2009. Subject: Energy cost adjustment clause.

Before the Public Utilities Commission of Nevada, Pre-Filed Direct Testimony on behalf of Nevada Power Company , Docket No. 09-02____. February 27, 2009. Subject: Prudence of gas purchase costs.

Before the Public Utilities Commission of Nevada, Pre-Filed Direct Testimony on behalf of Sierra Pacific Power Company, Docket No. 09-02_____. February 27, 2009. Subject: Prudence of gas purchase costs.

Before the Department of Public Utility Control of Connecticut, Direct Testimony on behalf of Connecticut Natural Gas Corporation. Docket No. 08-12-06. January 11, 2009. Subject: Cost of capital.

Before the Department of Public Utility Control of Connecticut, Direct Testimony on behalf of Southern Connecticut Gas Corporation. Docket No. 08-12-06. January 11, 2009. Subject: Cost of capital.

Before the Public Utility Commission of Texas, Rebuttal Testimony on behalf of Lone Star Transmission, LLC. Docket No. 35665. November 14, 2008. Subject: Licensing of new electricity transmission projects.

RECENT TESTIMONY (SINCE 2000 CONTINUED)

Before the Public Utilities Commission of Ohio, Direct Testimony on behalf of The Dayton Power and Light Company. Case No. 08-1094-EL-SSO. October 10, 2008. Subject: Cost of capital.

Before the Illinois Commerce Commission, Rebuttal Testimony on behalf of Northern Illinois Gas Company, Case No. 08-0363. September 25, 2008. Subject: Cost of capital.

Before the Illinois Commerce Commission, Testimony on behalf of Northern Illinois Gas Company, Case No. 08-0363. April 29, 2008. Subject: Cost of equity.

Before the Illinois Commerce Commission, Rebuttal Testimony on behalf of Shelby Coal Holdings, LLC, Christian Coal Holdings, LLC and Marion Coal Holdings, LLC. Docket No. 07-0446. April 7, 2008. Subject: Pipeline certification and competition in pipeline transport market.

Before the New York State Public Service Commission, Rebuttal Testimony on behalf of Iberdrola, S.A., Energy East Corporation, RGS Energy Group, Inc., Green Acquisition Capital, Inc., New York State Electric & Gas Corporation and Rochester Gas and Electric Corporation, Case No. 07-M-0906. January 31, 2008. Subject: Regulatory philosophy/ merger issues.

Before the Public Utilities Commission of Nevada, Rebuttal Testimony on behalf of Sierra Pacific Power Company, Docket No. 07-09016. January 14, 2008. Subject: Stand-alone costs and cost allocation issues.

Before the Public Utilities Commission of Nevada, Rebuttal Testimony on behalf of Sierra Pacific Power Company. Docket No. 07-09016. January 11, 2008. Subject: Allocation of pipeline transport costs.

Before the Illinois Commerce Commission, Testimony on behalf of Shelby Coal Holdings, LLC, Christian Coal Holdings, LLC and Marion Coal Holdings, LLC. Docket No. 07-0446. January 7, 2008. Subject: Pipeline certification and competition in pipeline transport market.

Before the Federal Energy Regulatory Commission, Affidavit on behalf of Consolidated Edison Company of New York, Docket No. OA08-13-000. January 7, 2008. Subject: Planning and allocation of electric transmission costs.

Before the Public Utilities Commission of Nevada, Direct Testimony on behalf of Sierra Pacific Power Company, Docket No. 07-09016. December 14, 2007. Subject: Stand-alone costs and cost allocation issues.

Before the New Hampshire Public Service Commission, Docket No. DE 07-064, invited appearance on an expert panel to present perspectives and answer questions on policies and practices regarding retail gas and electric distribution rate "decoupling," November 7, 2007.

Before the Public Utilities Commission of Nevada, Prefiled Direct Testimony on behalf of Sierra Pacific Power Company, Docket No. 07-05019. May 15, 2007. Subject: Prudence of gas purchase costs.

Before the United States Bankruptcy Court, Southern District of New York, Supplemental Report on behalf of Solutia, Inc., *et al.*, Debtors, Case No. 03-17949 (PCB) (Jointly Administered), April 20, 2007. Subject: Discount rate for contract rejection damages.

Before the Public Utilities Commission of Nevada, Rebuttal Testimony on behalf of Sierra Pacific Power Company, Docket No. 06-12001. April 19, 2007. Subject: Stand-alone costs and cost allocation issues.

RECENT TESTIMONY (SINCE 2000 CONTINUED)

Before the United States Bankruptcy Court, Southern District of New York, Supplemental Report on behalf of Solutia, Inc., et al., Debtors, Case No. 03-17949 (PCB) (Jointly Administered), March 23, 2007. Subject: Discount rate for contract rejection damages.

Before the United States District Court, District of Kansas, Expert Report on behalf of J.P. Morgan Trust Company, *et al*. in the matter of J.P. Morgan Trust Company, *et al*. V. Mid-America Pipeline Company, *et.al*., Docket No. 05-CV-2231-CM/JPO. March 21, 2007. Title: "Harm to Farmland's Coffeyville Refinery Expert Report", by Jeff. D. Makholm.

Before the Public Utilities Commission of Nevada, Prefiled Direct Testimony on behalf of Nevada Power Company, Docket No. 07-01022. January 16, 2007. Subject: Prudence of gas purchase costs.

Before the Public Utilities Commission of the State of Hawaii, Supplemental Testimony on behalf of Hawaii Electric Light Company, Inc., Docket No. 05-0135. December 29, 2006. Subject: Energy cost adjustment clause.

Before the Public Utilities Commission of the State of Hawaii, Testimony on behalf of Hawaiian Electric Company, Inc., Docket No. 2006-0386. December 22, 2006. Subject: Energy cost adjustment clause.

Before the Public Utilities Commission of Nevada, Pre-filed Direct Testimony on behalf of Sierra Pacific Power Company, Docket No. 06-12001. December 1, 2006. Subject: Stand-alone costs and cost allocation issues.

Before the State of New Jersey Board of Public Utilities, Prepared Reply Testimony on behalf of Public Service Electric & Gas, OAL Docket No. PUC1191-06 and BPU Docket No. EO05111005. November 3, 2006. Subject: Unregulated contract prices for telecommunication conduit rental contracts.

Before the State of New Jersey Board of Public Utilities, Rebuttal Testimony on behalf of the New Jersey American Water Company, Case No. WR06030257, October 10, 2006. Subject: Cost of Capital.

Before the Public Utilities Commission of Nevada, Rebuttal Testimony on behalf of Sierra Pacific Power Company, Docket No. 06-05016. October 2, 2006. Subject: Prudence of gas purchase costs.

Before the Federal Energy Regulatory Commission, Reply Testimony on behalf of the State of Alaska, Docket No. OR05-2-001, August 11, 2006. Subject: Relative risk and capital structure for the Trans Alaska Pipeline System (TAPS).

Before the Maine Public Utilities Commission, Response to the Bench Analysis on behalf of Central Maine Power Company, Docket 2005-729. May 19, 2006. Subject: Specification of productivity offset for price cap formula.

Before the Public Utilities Commission of Nevada, Rebuttal Testimony on behalf of Sierra Pacific Power Company, Docket No. 05-12001. May 17, 2006. Subject: Prudence of the company's gas hedging strategy.

Before the Public Utilities Commission of Nevada, Prefiled Direct Testimony on behalf of Sierra Pacific Power Company (Gas Division, WestPac Gas), Docket No. 06-0516. May 15, 2006. Subject: Prudence of the company's gas hedging strategy.

RECENT TESTIMONY (SINCE 2000 CONTINUED)

Before the State of New Jersey Board of Public Utilities, Testimony on behalf of the New Jersey American Water Company, Case No. WR06030257, March 29, 2006. Subject: Cost of Capital.

Before the Public Utilities Commission of Nevada, Direct Testimony on behalf of Nevada Power Company, Docket No.06-01016. January 17, 2006. Subject: Prudence of the company's gas hedging costs.

Before the New Brunswick Board of Commissioners of Public Utilities, Rebuttal Testimony on behalf of the Public Intervenor, Board Reference 2005-002. December 30, 2005 (original filing), January 23, 2006 (updated filing). Subject: Cost of capital.

Before the Public Utilities Commission of Nevada, Pre-Filed Direct Testimony on behalf of Sierra Pacific Power Company, Docket No.05-12001. December 1, 2005. Subject: Prudence of the company's gas hedging costs.

Before the Public Utilities Commission of Nevada, Pre-Filed Rebuttal Testimony on behalf of Sierra Pacific Power Company, Docket No.05-9016. December 2, 2005. Subject: Prudence of the company's energy supply plan.

Before the Public Utilities Commission of Nevada, Pre-Filed Rebuttal Testimony on behalf of Nevada Power Company, Docket No.05-9017. December 2, 2005. Subject: Prudence of the company's energy supply plan.

Before the Public Utilities Commission of Ohio, Supplemental Testimony on behalf of The Dayton Power and Light Company. Case No. 05-276-EL-AIR. September 26, 2005. Subject: Cost of capital.

Before the Illinois Commerce Commission, Surrebuttal Testimony on behalf of Northern Illinois Gas Company d/b/a Nicor Gas Company. Case No. 04-0779. May 12, 2005. Subject: Cost of capital.

Before the United States Bankruptcy Court, Northern District of Texas, Fort Worth Division, Reply Report on behalf of Mirant Corporation, et al, Debtors. Case No. 03-46590 (Jointly Administered). April 12, 2005. Subject: Pipeline capacity valuation.

Before the Public Utilities Commission of Nevada, Rebuttal Testimony on behalf of Sierra Pacific Power Company. Docket No 05-1028. April 12, 2005. Subject: Prudence of gas purchase costs.

Before the Illinois Commerce Commission, Rebuttal Testimony on behalf of Northern Illinois Gas Company d/b/a Nicor Gas Company. Case No. 04-0779. April 5, 2005. Subject: Cost of capital.

Before the United States Bankruptcy Court, Northern District of Texas, Fort Worth Division, Report on behalf of Mirant Corporation, et al, Debtors. Case No. 03-46590 (Jointly Administered). March 22, 2005. Subject: Pipeline capacity valuation.

Before the Public Utilities Commission of the State of Oregon, Direct Testimony and Exhibits on behalf of Portland General Electric. Docket No.UE-88 Remand. February 15, 2005. Subject: The cost consequences of abandoning the regulatory compact in Oregon on prudent invested capital.

Before the Louisiana Public Service Commission, testimony on behalf of Entergy Gulf States, Ind., and Entergy Louisiana, Inc., in Re: Analysis of Competitive Implications, Consolidated Docket No. U-21453, et al, January 13, 2005. Subject: Retail electricity competition.

Before the Public Utilities Commission of Nevada, Testimony and Exhibits on behalf of Sierra Pacific Power Company. Docket No 05-1028. January 5, 2005. Subject: Prudence of gas purchase costs.

RECENT TESTIMONY (SINCE 2000 CONTINUED)

Before the Public Utility commission of Oregon, Direct Testimony on behalf of Portland General Electric. Docket No. UE-165. November 17, 2004. Subject: Power supply risk related to PGE's hydroelectric generation sources.

Before the Public Utilities Commission of Nevada, Testimony on behalf of Nevada Power Company. Docket No. 04-11028. November 10, 2004. Subject: Examination of the prudence of gas purchase and hedging decision in the Company's 2004 deferral case.

Before the Illinois Commerce Commission, Testimony on behalf of Nicor Gas Company. Docket No. 04-0779. November 1, 2004. Subject: Cost of Capital.

Rebuttal Report for an ad-hoc arbitration on behalf of CITIBANK, N.A. in their case against NEW HAMPSHIRE INSURANCE COMPANY. Policy No. 576/ MF5113500. October 15, 2004. Subject: Claimants right to collect on a political risk insurance policy as a result of the expropriation of a toll-road concession's assets in Argentina.

Before the International Center for the Settlement of Investment Disputes, Testimony on behalf of Azurix Corp., in the case of Azurix Corp v. Government of Argentina in Paris, France, October 11th, 2004. Subject: Expropriation of a water utility concession in the province of Buenos Aires.

Before the Circuit Court of Fairfax, Virginia, Testimony on behalf of Upper Occoquan Sewage Authority in the case against Blake Construction Co., Inc., Poole and Kent, a Joint Venture. Case No. 206595. October 1, 2004. Subject: Valuation of capacity expansion project.

Expert Report for an ad-hoc arbitration on behalf of CITIBANK, N.A. in their case against NEW HAMPSHIRE INSURANCE COMPANY. Policy No. 576/ MF5113500. October 1, 2004. Subject: Claimants right to collect on a political risk insurance policy as a result of the expropriation of a toll-road concession's assets in Argentina.

Before the London Courts of International Arbitration, Rebuttal Report on behalf of CITIBANK, N.A. AND DRESDNER BANK AG in their case against AIG EUROPE (UK) LTD. AND SOVEREIGN RISK INSURANCE. Arbitration No. 3473. September 17, 2004. Subject: Claimants right to collect on a political risk insurance policy as a result of the expropriation of electric utility assets in Argentina.

Before the London Courts of International Arbitration, Expert Report on behalf of CITIBANK, N.A. AND DRESDNER BANK AG in their case against AIG EUROPE (UK) LTD. AND SOVEREIGN RISK INSURANCE. Arbitration No. 3473. August 6, 2004. Subject: Claimants right to collect on a political risk insurance policy as a result of the expropriation of electric utility assets in Argentina.

Before International Center for the Settlement of Investment Disputes, Rebuttal Report on behalf of Azurix Corp., in the case of Azurix Corp v. Government of Argentina, April 15th, 2004. Subject: Expropriation of a water utility concession in the province of Buenos Aires.

Before the Public Utilities Commission of Nevada, Rebuttal Testimony on behalf of Sierra Pacific Power Company. Case No: 03-12002. March 29, 2004. Subject: Rebutted argument that there was a link between the merger and the cost of electricity in the post-merger period.

Before the Public Utilities Commission of Nevada, Rebuttal Testimony on behalf of Nevada Power Company. Case No: 03-10001 and 03-10002. February 5, 2004. Subject: Rebutted argument that there was a link between the merger and the cost of electricity in the post-merger period.

RECENT TESTIMONY (SINCE 2000 CONTINUED)

Before the New Zealand Commerce Commission, Testimony on behalf of Orion New Zealand. November 5, 2003. Subject: Productivity measures used in resetting the price path thresholds for electricity distributors in New Zealand.

Before the Public Utilities Commission of Nevada, Rebuttal Testimony on behalf of Sierra Pacific Power Company. Case No: 03-5021. September 2, 2003. Subject: Structure in place for governing and overseeing hedging/risk management process at Westpac Utilities, an operating division of Sierra Pacific Power Company.

Before the State of Maine Public Utilities Commission, Rebuttal Testimony on behalf of FairPoint New England Telephone Companies. July 11, 2003. Subject: Cost of capital.

Before the Public Utilities Commission of Nevada, Testimony on behalf of Sierra Pacific Power Company. Case No: 03-5021. May 14, 2003. Subject: Structure in place for governing and overseeing hedging/risk management process at Westpac Utilities, an operating division of Sierra Pacific Power Company.

Before the Public Utilities Commission of Nevada, Rebuttal Testimony on behalf of Sierra Pacific Power Company. Case No: 03-1014. May 5, 2003. Subject: Prudence of gas procurement and hedging program.

Before the State of Maine Public Utilities Commission, Direct Testimony on behalf of FairPoint New England Telephone Companies. April 7, 2003. Subject: Cost of capital.

Before the Public Utilities Commission of Nevada, Rebuttal Testimony on behalf of Nevada Power Company. Case No: 02-11021. March 31, 2003. Subject: Prudence of gas procurement and hedging program.

Before Federal Communications Commission, Testimony on behalf of Iowa Telecommunications Services, Inc. Case No. March 25, 2003. Subject: Cost of capital.

Before Federal Energy Regulatory Commission, Testimony on behalf of PPL Wallingford Energy LLC. Case No: ERO3-421-000. January 9, 2003. Subject: Cost of equity.

Before the State of New Hampshire Public Utilities Commission, Rebuttal Testimony on behalf of Kearsarge Telephone Company. Case No. DT 01-221. December 20, 2002. Subject: Rebuttal on cost of equity.

Before the New York State Public Service Commission, Affidavit in support of Rochester Gas and Electric Corporation’s Response to Staff’s November 8, 2002 filing. Case No. 02-E-0198, 02-G-0199. November 14, 2002. Subject: Respond to staff’s filing with respect to the rate-of-return and risk impacts of various regulatory mechanisms.

Before the Public Utility Commission of Texas, Rebuttal Testimony on behalf of American Electric Power Company, Inc., Mutual energy CPL, LP, Mutual Energy WTU, LP and Centrica PLC, Centrica N.S. Holding, Inc., Centrica Holdco, Inc.. Case No. 25957. October 28, 2002. Subject: Impact of the merger on competition in the retail electric market.

Before the International Center for the Settlement of Investment Disputes, Expert Testimony on behalf of Azurix Corp in the case of Azurix Corp v. Government of Argentina, October 15, 2002. Subject: Expropriation of a water utility concession in the province of Buenos Aires.

RECENT TESTIMONY (SINCE 2000 CONTINUED)

Before the State of New York Public Service Commission, Rebuttal Testimony on behalf of Rochester Gas and Electric Corporation. Case No. 02-E-0198, Case No. 02-G-0199. September 30, 2002. Subject: Cost of capital

Before the Connecticut Department of Public Utility Control, Update and Rebuttal Testimony on behalf of The United Illuminating Company, Case No. 01-10-10, April 4, 2002. Subject: Cost of capital.

Before the State of New York Public Service Commission, Direct Testimony on behalf of Rochester Gas and Electric Corporation. Case No. 02-E-0198, Case No. 02-G-0199. February 15, 2002. Subject: Cost of capital.

Before the Alberta Energy and Utilities Board, Update of Evidence on behalf of UtiliCorp Networks Canada, November 30, 2001. Subject: Testimony on the elements of the company's performance based regulation plan.

Before the Connecticut Department of Public Utility Control, Direct Testimony on behalf of The United Illuminating Company, Case No. 01-10-10, November 15, 2001. Subject: Cost of capital.

Before the Illinois Commerce Commission, Surrebuttal Testimony on behalf of Commonwealth Edison Company, Case No. 01-0423, October 24, 2001. Subject: Economic pricing for unbundled retail distribution services.

Before the Illinois Commerce Commission, Rebuttal Testimony on behalf of Commonwealth Edison Company, Case No. 01-0423, September 18, 2001. Subject: Economic pricing for unbundled retail distribution services.

Before the State of New York Public Service Commission, Prepared Rebuttal Testimony on behalf of New York State Electric & Gas Corporation. Case 01-E-0359. September 12, 2001. Subject: Electric price protection plan

Before the State of Maine Public Utilities Commission, Joint Rebuttal Testimony on behalf of Community Service Telephone Company. September 6, 2001 (with C. Zarkadas). Subject: Cost of equity capital.

Before the Public Service Commission of the State of Missouri, Rebuttal Testimony on behalf of Gateway Pipeline Company. Case GM-2001-595. August 20, 2001. Subject: Acquisition of Capital Stock of Utilicorp Pipeline Systems, and connection.

Before the State of New York Public Service Commission, Prepared Direct Testimony on behalf of New York State Electric & Gas Corporation. Case 01-E-0359. August 3, 2001. Subject: Electric price protection plan.

Before the Federal Energy Regulatory Commission, Prepared Answering Testimony on behalf of the Association of Oil Pipe Lines. Case No: OR96-2-000. June 21. 2001. Subject: Light-handed regulation of oil pipeline tariffs.

Before the Illinois Commerce Commission, Direct Testimony on behalf of Commonwealth Edison Company, Case No. 01-0423, June 1, 2001. Subject: Economic pricing for unbundled retail distribution services.

Before the Federal Energy Regulatory Commission, Affidavit on behalf of Florida Power & Light Co. May 31, 2001. Subject: Pricing of transmission services.

RECENT TESTIMONY (SINCE 2000 CONTINUED)

Before the Public Utility Commission of the State of Oregon, Rebuttal Testimony on behalf of Portland General Electric Company. May 21, 2001. Subject: Cost of capital.

Before the State of Maine Public Utilities Commission, Direct Testimony on behalf of Community Service Telephone Company. April 4, 2001 (with C. Zarkadas). Subject: Cost of equity capital.

Before the State of New Jersey Board of Public Utilities, Cross-Answering Testimony on behalf of Public Service Electric and Gas Company, Case No. GM00080564, March 26, 2001. Subject: Forecasting the net market value for natural gas transportation and storage contracts.

Before the Indiana Utility Regulatory Commission, Testimony on behalf of Tipton Telephone Company, Inc, February 23, 2001 (with C. Zarkadas). Subject: Cost of capital.

Before the Supreme Court of Victoria at Melbourne, in the matter of an appeal brought by TXU Electricity Limited of the Final Determination of the Office of the Regulator General of the 2001 to 2005 tariffs for the Victorian electricity distributors. Testimony on behalf the Office of the Regulator General, February 11, 2001. Subject: The distinctions between price cap and rate of return regulatory practices.

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"The Difficult Economics of a Worldwide LNG Commodity Market," International Bar Association Annual Conference, Oil and Gas Law Committee Section. Washington DC, September 22, 2016

"How to Make LNG Accessible to All of Europe?" CEER Workshop. Athens, Greece, September 12, 2016.

"Gas Markets, Gas Use and Europe's Gas Supply from the East," Eurasian Natural Gas Infrastructure Conference, Istanbul, Turkey, June 9, 2015

"International Perspective on Pathways for Gas Market Reform in Australia," Australian Domestic Gas Outlook, 2016, Sydney, Australia, March 8, 2016.

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"Ensuring Natural Gas Availability," MIT Energy Initiative, 2013 MITEI Symposium, Cambridge, Massachusetts, April 16, 2013.

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"The Role of Regulation and the Challenges Going Forward," Speech given at the 10th Annual Tufts Energy Conference, Panel 3: The Natural Gas Boom. Medford, Massachusetts, February 21, 2015.

"Natural Gas in the Transformation Process in Europe," German Institution for Economic Research (DIW Berlin), Schumpeter Hall, Berlin, Germany. May 15, 2012.

"The Trouble with Europe: Infrastructure, Institutions and Investment," Keynote Speech at EPRG Winter Seminar 809. Cambridge, U.K., December 5, 2011.

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"Governance and the Electricity Sector," Governance and Regulation in the Electricity Sector Conference. Toronto, Ontario, June 4, 2010.

"Public Utility Companies and Regulatory Risk," Saul Ewing's 4th Annual Public Utility Symposium. Philadelphia, PA, May 24, 2010.

"It's All About Inland Transportation," US Gas Pipelines Reflect What's Happening in Europe," Florence School of Regulation Specialized Training on Regulation of Gas Markets. Florence, Italy, March 24, 2010.

"Windmills and Wires: FERC Rate Cases, Transmission Cost Allocation, and Renewable Power Development," Law Seminars International Sixth Annual National Conference on Today's Utility, Las Vegas, Nevada, February 11, 2010.

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"Vertical Relations in Energy Markets: On the Role of Contracts and Other Legal Entitlements in the U.S. Gas Transport Market", Vienna University of Economics and Business, Workshop 2009. Vienna, Austria, May 29, 2009.

"Institutional, Transactional and Political Barriers to Competitive Gas Market in Europe: Europe's Pipelines and Economics," Florence School of Regulation Workshop: Tariffs for European Gas Transmission Networks. Florence, Italy, March 6, 2009.

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"Alaska as a Gas Supplier: Where is the North Slope Gas Going, and How?" Law Seminars International, Energy in Alaska conference. Anchorage, Alaska, December 8-9, 2008.

"Maintaining Adequate Infrastructure in the Natural Gas and Electric Industries," Increasing Longer-Term Stability in Energy Markets conference sponsored by the Institute for Regulatory Policy Studies. Springfield, Illinois, May 1, 2008.

"Rate Decoupling and Associated Rate and Cost Issues," New Hampshire Public Utilities Commission, Concord, New Hampshire, November 6, 2007.

"Electricity Transmission Cost Allocation in New England: A Throwback to an Earlier Era in Gas Transmission," Law Seminars International, Energy in the Northeast conference, Boston, Massachusetts, October 18-19, 2007.

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“Open Access in Gas Transmission,” New England Chapter of the International Association for Energy Economics, Boston, Massachusetts, December 13, 1995.

“Light-Handed Regulation for Interstate Gas Pipelines,” Twenty-Seventh Annual Institute of Public Utilities Conference, Williamsburg, Virginia, December 12, 1995.

“Ending Cost of Service Ratemaking,” Electric Industry Restructuring Roundtable, Boston, Massachusetts, October 2, 1995.

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“Initial Comments on AGLGN’s Revised Access Arrangement Information” on behalf of BHP (March 20th, 1999). This submission presents NERA’s comment to AGLGN submission to IPART in New South Wales, Australia.

“International Restructuring Experience” (February 12th, 1999). This paper surveys a number of countries whose experience of restructuring and competition in the electricity sector is directly relevant to the proposed changes in Mexico – Argentina, Australia, Chile, Guatemala, New Zealand, Norway, Spain, the US and the UK

“Report I: Review of the Regulatory Framework” (January 18th, 1999). This report presents the options for a natural gas framework in Peru.

“Conceptual Framework for the Reform of the Electricity Sector in Mexico: White Paper” (November 24th, 1998). This report represents the White Paper for restructuring of the electricity sector in Mexico which is being used in Congress for debate.

“Precios del Gas Natural para la Generación de Electricidad en el Perú” (November 16th, 1998). This report analyzes different alternatives for the treatment of natural gas prices in the electricity tariff model (report in Spanish).

“Tariffs and Subsidies: Report for the Tariffs Group” (November 10th, 1998). This report presents recommendation on the path for tariffs and subsidies for 1999 to the Electricity Tariffs Group of the Government of Mexico.

“Gasoducto México-Guatemala: Informe Final” (October 22nd, 1998). This report analyzes the legal and regulatory framework in both Mexico and Guatemala and costs and volumes for the building of a natural gas pipeline connecting both countries. A copy of the report was given by President Zedillo (Mexico) to President Arzú (Guatemala) (report in Spanish).

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"Fuels Policy Group: Recommendations" (September 11th, 1998). This report presents recommendations to the Government of Mexico on their fuels policies for the electricity sector.

"Análisis de Costos e Inversiones. Revisión Tarifaria de Transener" (August 25, 1998). Report given to ENRE (the Argentinean electricity regulator) on behalf of a Consortium of Generators on the analysis of costs and investments to be considered for the revenue requirement of the electricity transmission company (report in Spanish).

"Central America Pipeline: Regulatory Analysis and Proposal" (July 28, 1998). This report presents the regulatory analysis and development of a fiscal, legal and commercial framework proposal for gas import, transportation, distribution and marketing in El Salvador, Honduras and Guatemala regarding the proposed Central American Pipeline.

"Energy Regulation in El Salvador" (July 28, 1998). This report presents a deep analysis of the electricity and natural gas regulatory, legal and tax frameworks in El Salvador.

"Energy Regulation in Guatemala" (July 28, 1998). This report presents a deep analysis of the electricity and natural gas regulatory, legal and tax frameworks in Guatemala.

"The Cost of Capital for Gas Transmission and Distribution Companies in Victoria" (June 22, 1998). Report prepared for BHP Petroleum Pty Ltd.

"Principios Económicos Básicos de Tarificación de Transmisión Eléctrica. Revisión Tarifaria de Transener" (May 26, 1998). The main purpose for this report was to provide an economic and regulatory analysis of laws, decrees, license and documents of the tender to provide advise in the tariff review of Transener (the electricity transmission company in Argentina), to present an economic analysis of transmission tariffs and to provide an opinion on specific topics to be discussed in the public hearing. This report was written for a consortium of generators in Argentina (reports in English and Spanish)

"Asesoría en la Fijación de Tarifas de Transener y Normativa del Transporte, Benchmarking Study" (May 26, 1998). This report compares the costs of Transener (the electricity transmission company in Argentina) with those of other companies elsewhere for a consortium of generators (the electricity transmission company in Argentina).

"International Regulation Tool Kit: Argentina" (March 20, 1998). This document describes the natural gas regulatory framework in Argentina for BG.

"Tarificación de los Servicios Que Prestan las Terminales de Gas LP" (January 9, 1998). The final report given to PEMEX Gas y Petroquímica Básica (México) for the determination of rates for LPG terminals.

"NERA-Pérez Companc Distribution Tariff Model" (January 5, 1998). This report explains the methodology behind NERA's calculations of distribution tariffs for Pérez Companc in Monterrey.

"Monterrey Natural Gas Market Assessment," (January 5, 1998). A series of reports were written to present the results of the market study of the demand for natural gas in the geographic zone of Monterrey to a company interested in bidding for the natural gas distributorship.

"Resolving the Question of Escalation of Phases (bb) and (cc) Under the Maui Gas Sale and Purchase Contract", prepared for the New Zealand Treasury, December 16, 1997.

"Timetable and Regulatory Review for the Monterrey International Public Tender," (December 5, 1997). A description of the necessary steps to bid for a distribution company as well as an explanation and analysis of natural regulations in Mexico for Pérez Companc.

"Economic Issues in the PFR for 18.3.1(I)(bb) & (cc)", prepared for the New Zealand Treasury, November 17, 1997.

"NERA's Distribution Tariff Model" (October 29, 1997). This report explains the methodology behind NERA's calculations of distribution tariffs for MetroGas.

"Evaluation Design Standards for MetroGas," (October 24, 1997). This report dealt with the analytical support resulting from work with MetroGas to create a meticulously-documented security criterion analysis that supported its efforts to obtain due recognition—and appropriate tariff treatment—for its costs.

"Ghana Natural Gas Market Assessment," prepared for the Ministry of Mines and Energy, Ghana (March-July, 1997). A series of four reports assessing prospective gas demand usage and netback prices for a number of proposed pipeline project alternatives.

"Final Report for Russian Oil Transportation & Export Study: Commercial, Contractual & Regulatory Component," prepared for The World Bank, June 25, 1997.

Response to FIEL's criticisms regarding NERA's report "Cálculo del Factor de Eficiencia (X)" (June 2, 1997).

"Impacts on Pemex of Natural Gas Regulations" prepared for Pemex Gas y Petroquímica Básica México, May 21, 1997.

"Market Models for Victoria's Gas Industry: A Review of Options," April 1997, prepared for Broken Hill Proprietary (BHP) Petroleum, to propose an alternative model for gas industry restructuring in Victoria, Australia.

"New Market Arrangements for the Victorian Gas Industry," prepared for Broken Hill Proprietary Petroleum; March 13, 1997.

"CEG Privatization: Comments to the Regulatory Framework," prepared for Capitaltec Consultoria Economica SA describing our comments with respect to the regulatory framework and the license proposed in the privatization of Riogas and CEG in Rio de Janeiro, Brazil; March 7, 1997.

"Determination of the Efficiency Factor (X)," prepared for ENARGAS, Argentina, January 24, 1997.

"Determination of Costs and Prices for Natural Gas Transmission," prepared for Pemex Gas y Petroquímica Básica, México, December 19, 1996.

"Regulating Argentina's Gas Industry," a report prepared for The Ministry of Economy and The World Bank, November 26, 1996.

"Open Access and Regulation," prepared for Gascor, in the State of Victoria, Australia; (October 2, 1996).

"A Review and Critique of Russian Oil Transportation Tariffs (Russian Oil Transportation & Export Study; Commercial, Contractual & Regulatory Component)," prepared for The World Bank, June 13, 1996.

"Tariff Options for Transneft (Russian Oil Transportation & Export Study; Commercial, Contractual & Regulatory Component)," prepared for The World Bank, June 6, 1996.

"Comments on the Proposed Amendments to the Regulation of Airports in New Zealand," prepared for the New Zealand Parliament Select Committee hearings on the regulation of monopolies, March 13, 1996.

"Evaluating the Shell Camisea Project," prepared for Perupetro S.A., Government of Peru, December 8, 1995.

"Towards a Permanent Pricing and Services Regime," prepared for British Gas, London, England, November, 1995.

"Final Report: Gas Competition in Victoria," prepared for Gas Industry Reform Unit, Office of State Owned Enterprises, June 1995.

"Natural Gas Tariff Study," prepared for the World Bank, May 1995, consisting of:

Principles and Tariffs of Open-Access Gas Transportation and Distribution Tariffs
Handbook for Calculating Open-Access Gas Transportation and Distribution Tariffs

"Economic Implications of the Proposed Enerco/Capital Merger," prepared for Natural Gas Corporation of New Zealand, December 1994.

"Contract Terms and Prices for Transportation and Distribution of Gas in the United States," prepared for British Gas TransCo, November 1994.

"Economic Issues in Transport Facing British Gas," prepared for British Gas plc, December 1993.

"Overview of Natural Gas Corporation's Open-Access Gas Tariffs and Contract Proposals," prepared for Natural Gas Corporation of New Zealand, October 1993.

JUDGE EYSTER: Ms. Newell.

MS. NEWELL: Thank you, your Honor.

JUDGE EYSTER: By the way, how is Jack doing?

MS. NEWELL: Let's not go there this morning. No, he's doing fine.

JUDGE EYSTER: I haven't seen him in a long time.

MS. NEWELL: Yeah. He has not changed, and still keeps up on the Red Bull, so you can imagine how that is.

JUDGE EYSTER: He was very entertaining when he was here.

MS. NEWELL: Entertaining is one way to put it.

JUDGE EYSTER: All right. Sorry about that.

MS. NEWELL: No, that is fine.

Pursuant to the stipulation of the parties, we are moving to bind in the following testimony of Energy Michigan. Energy Michigan had four witnesses. The first one is Mr. Alexander J. Zakem, who filed direct testimony, which consisted of a cover page, a title page, and 68 pages of questions and answers. And attached to that testimony there were also six exhibits, EM-1, EM-2, EM-3, EM-4, EM-5, and EM-6. Mr. Zakem also filed rebuttal testimony, which consisted of a cover page and 15 pages of questions and answers. And there was also an exhibit to Mr. Zakem's rebuttal testimony, EM-16. And I handed out to the parties this morning, there was one modification to the testimony and to the exhibit, and the only change that was made was the correction of the exhibit number, and those corrections in the testimony were made to page 1, line 13; page 13, line 14; and page 14, line 7; and then on the exhibit, the appropriate exhibit number was listed, and that's in the testimony which we provided to the court reporter this morning.

In addition to that testimony, we also move for the admission of the direct testimony of Ralph C. Smith, which consisted of a cover page, a title page, and 20 pages of questions and answers. Attached to Mr. Smith's testimony were four exhibits, EM-7, EM-8, EM-9, and EM-10.

We move for the admission as well of the direct testimony of Rupert R. Jennings, which consisted of a cover page, a title page, and ten pages of testimony. Attached to Mr Jennings' testimony were five exhibits, EM-11, EM-12, EM-13, EM-14, and EM-15.

And finally, we move for the admission of the direct testimony of Lael E. Campbell, which consisted of a cover page and ten pages of testimony. There were no exhibits to Mr. Campbell's testimony.

So we move for the admission of those testimony and exhibits.

JUDGE EYSTER: Any objections?

The testimony is bound in, and the exhibits are admitted.

(Testimony bound in.)

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STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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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

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

ALEXANDER J. ZAKEM
DIRECT TESTIMONY

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. <u>PA 341 is not the only law that applies</u> 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. <u>How the Commission will harmonize Section 6w and MCL 460.11(1)</u> 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 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 share and equitable use of the electric grid. [. . .]
>
> [. . .] 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. [. . .] *[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 additional 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. <u>Without a change in that MISO tariff</u>, 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, <u>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</u>. 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 additional 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 historical investment in facilities that would not 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 additional 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 capacity-related 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:

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[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?

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[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 final 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, <u>normal utility capacity plans will preserve zonal reliability</u>. Therefore, zonal reliability becomes a financial issue, not a reliability one. <u>DTE does not have to do anything different</u> 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 <u>cost of the new replacement resources</u> would be <u>shared by all of the LSEs</u> 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, <u>MISO has control of all capacity resources no matter who owns the rights to the ZRCs</u> 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 <u>any resource that the appropriate independent system operator allows to meet the capacity obligation of the electric provider</u>. The preceding sentence shall <u>not be applied in any way that conflicts with a federal resource adequacy tariff</u>, 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 electric utility 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 alternative electric supplier . . . 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 *maintains the current quantity of local resources – which is ample for maintaining reliability*. Zone 7 is a no-electric-growth area. Thus, as present resources are *retired and replaced*, 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. Utilities assert they do not have capacity to provide for ROA customers and that any services will either be from new resources or the MISO auction.

Visible Price: CONE is a visible cost of the capacity product 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 <u>review of the prudent investment in new resources</u>, 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 <u>no longer a projected shortfall</u>. The latest <u>2017 MISO/OMS report shows reserve margins of about 20% through 2022.</u> 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:

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[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 341 for **DTE ELECTRIC COMPANY'S** service territory.	))))))	**Case No. U-18248**

REBUTTAL TESTIMONY

OF

ALEXANDER J. ZAKEM

ON BEHALF OF

ENERGY MICHIGAN, INC.

Q. Please state your name and business address.

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

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

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

Q. Are you the same Alexander J. Zakem who provided direct testimony in this proceeding?

A. Yes, I am.

Q. Are you sponsoring any exhibits in your rebuttal testimony?

A. Yes, I am sponsoring Exhibit EM-16 (AJZ-~~6~~7).

Q. Was this exhibit prepared by you or under your supervision?

A. Yes, it was.

Q. What is the purpose of your testimony?

A. On behalf of Energy Michigan, I am addressing how the subtractions for all energy market sales and other sales specified in Section 6w(3) subparagraph (b) of PA 341 should be included in the proposed SRM charges of the Commission Staff, ABATE, and Constellation. I am not addressing or critiquing the SRM proposals of these parties that relate to capacity-related generation costs, but rather advising the Commission of how the subtractions specified in the statute might be applied.

Q. Would you summarize your conclusions?

A. In summary, Section 6w(3) subparagraph (b) must be applied to the outcome of "capacity-related generation costs" under subparagraph (a) for the implementation of an SRM charge to be complete. If, under the Michigan cost of service statute, capacity related costs are determined from methods other than embedded costs, then subtraction for the various sales in subparagraph (b) is not needed.

In short, the application of a credit for "all energy market sales" and other sales specified in subparagraph (b) is straightforward:

1. If "capacity-related generation costs" are extracted from the utility's base rates under subparagraph (a), then "all energy market sales" net of fuel must be subtracted under subparagraph (b). The two subparagraphs in Section 6w(3) go together.

2. If the SRM charge is determined by a method that does not use the utility's embedded costs, then no subtraction for "all energy market sales" is needed.

Q. Which proposed SRM charges use embedded costs and which do not?

A. DTE Electric ("DTE"), Staff, ABATE, and Constellation offer an SRM charge where the "capacity-related generation costs" are based on embedded costs, where a subtraction is required. Staff and Constellation also offer an SRM charge based on costs benchmarks other than embedded, so no subtraction is required.

Q. Are there other statutes that apply to rates set by the Commission including the SRM charge?

A. As described in my Direct Testimony, Michigan's cost of service statute, MCL 460.11(1), also 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. Thus, two statutes – not one – apply to the setting of the SRM charge. How the Commission will harmonize Section 6w and MCL 460.11(1) is open to legal argument. In this rebuttal testimony, I will describe how the subtractions for all energy market sales and other sales should, in my view, be applied to SRM charges determined from PA 341 and from MCL 460.11(1).

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 components of the SRM charge are described in the statute, and it is necessary to cite that statute, as did DTE in its Application and testimony. So I will recognize and explain the practical effect of implementation choices presented to the Commission under Section 6w and MCL 460.11(1), namely, the subtraction for all energy market sales.

Q. What does PA 341 specify as components of the SRM charge?

A. Section 6w(3) describes two components of the SRM charge, in subparagraphs (a) and (b). Subparagraph (a) in part states:

> . . . 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 purchases or lease of the capacity resource from a third party. [Section 6w(3)(a). Emphasis added.]

Subparagraph (b) in part states:

> . . . subtract all non-capacity-related electric generation costs, including, but not limited to . . . the projected revenues, net of projected fuels 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.
>
> [Section 6w(3)(b). Emphasis added.]

Q. What are "all energy market sales"?

A. MISO buys all energy injected into the grid, except what is scheduled to a receiver external to MISO. MISO also charges for all load. 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 used by bundled customers. Therefore, netting of MWh energy generation against MWh of energy load is inaccurate and does not reflect the real and complete sales to the MISO market. For this reason, it would be inaccurate to net MISO sales against bundled customer load and subtract only the difference.

It would also be potentially in conflict with the plain meaning of the statutory language to assume "all energy market sales" means only the hourly amount above the utility's load as an LSE. The statute specifically calls only for netting of "projected fuel costs" while specifically stating "all" energy market sales. See Section 6w(3)(b).

To be clear, MISO in its bill to a market participant may offset some charges against some credits to get to one payable number for a particular service. This is not what I mean by "netting" of energy in the explanation above.

Q. Could it also make sense to interpret "all energy market sales" as either net of purchases annually or net of customer load hourly?

A. Although that is for the Commission to decide, there are difficulties with such an interpretation. Load and generation can be priced differently, so the net dollars that go with net energy may have no meaning. If "all energy market sales" were net of purchases, what would "net of projected fuel costs" mean for projected purchases? While totals can always be netted, such totals may not be meaningful to subparagraph (b). I cannot see a way to make netting of sales with purchases work, under the MISO market.

The plain meaning of "all energy market sales" would be everything sold, meaning everything that MISO pays for. The Commission could interpret "sales" as wholesale or retail, but my opinion is that wholesale is the appropriate meaning. The word "all" is attached to "energy market sales." Presumably, this is for emphasis, since "all" is not attached to "off-system energy sales," "ancillary services sales," and "energy sales under unit-specific bilateral contracts" yet the plain meaning of these three types of sales would be all such sales as well.

Q. Section 6w(3) subparagraph (b) states "net of projected fuel costs." How should this be applied?

A. The words have no qualifier, such as "hourly" or "marginal" or "average." The statement is a flat "projected fuel costs," not cost of goods sold or a cost imputed for a specified sale. PA 341 was a negotiated statute. Plain meaning would indicate total fuel costs during the period under study, which would be a year, which Mr. Jennings has done in his projections.

Q. What is included in Energy Michigan's assessment of "all energy market sales"?

A. Energy Michigan witness Mr. Jennings explains the inclusions on pages 7-10 of his direct testimony. The sales include both DTE-owned power plants and generation related to purchase power agreements, as Mr. Jennings notes on page 7 of his testimony, lines 22-24.

Q. Why are purchases included, when the statute says "sales."

A. While it is the Commission's responsibility to determine the subtraction for "all energy market sales," Energy Michigan is laying out and valuing the complete picture for the Commission.

MISO pays the Locational Marginal Price ("LMP") for energy injected into the market, and that transaction is the "sale." The question is, "Who gets paid the LMP for the sale? Is it DTE, or is it the party selling to DTE?"

In DTE's PSCR Plan filing for 2017, Case No. U-18143, DTE reports the purchase price of the energy purchases for its MISO Wholesale Purchases, Renewable Purchases, and other purchases. If the selling party were credited by MISO with the energy sale into the MISO market, then the selling party would be collecting twice, so to speak: collecting the purchase price from DTE and collecting the LMP from MISO. So obviously the selling party is not receiving the energy market LMP price from MISO.

If the selling party were receiving the LMP from MISO but passing it on to DTE, then the DTE PSCR would show as an expense only the difference between the purchase price and the MISO LMP. But the PSCR shows the full purchase price, not a difference.

MISO charges for all load, but there is no such charge reported. DTE, therefore, according to its PSCR accounting, is apparently paying the full purchase price to the selling party and receiving from MISO the LMP value for energy injected into the MISO market. This is the sale to MISO – dollar credit for energy injected into the MISO market.

Q. Are there other factors that could affect the Commission's interpretation of Section 6w(3) subparagraph (b)?

A. PA 341 (as Senate Bill 437) was debated, deliberated, and revised over an 18-month period. The outcome, in my view, is not a carefully constructed rate design but rather a negotiated agreement among the parties involved. Some words were put in, other words were taken out, trade-offs were made, and the final result is the deal. I do not know what was conceded in return for the words "all energy market sales." The Commission will have to interpret the intent of subparagraph (b), but I believe it is important for Commission to bear in mind that PA 341, and in particular Section 6w(3), is the product of a negotiated deal and not necessarily a unified, self-coherent, and internally consistent proposal.

Q. Under its plain meaning, how should Section 6w(3)(b) be applied to an SRM charge?

A. Again, there are two statutes that govern the setting of rates, PA 341 and the cost of service statute 460.11(1). First, if the Commission or a party uses subparagraph (a) – "*capacity-related generation costs included in the utility's base rates, surcharges, and power supply cost recovery factors*" – then it should also include the subtraction for subparagraph (b) – "*projected revenues, net of projected fuels costs, from . . . all energy market sales*." For example, DTE determined its SRM charge using the embedded costs per subparagraph (a), but did not subtract "all energy market sales" as required by subparagraph (b).

Energy Michigan, in the testimonies and exhibits of witnesses Mr. Smith and Mr. Jennings showed how the subtraction should be done, using Mr. Jennings' projection of DTE generation.

Second, if the Commission or a party uses a cost-of-service pricing method that is not based on the utility's embedded costs, then subparagraph (b) should not apply.

Q. What is the value of the subtraction for subparagraph (b)?

A. In his testimony and exhibits, Energy Michigan witness Mr. Jennings has determined that on a projected basis, the value is $584 million, considering all energy used by DTE and all fuel. This number is for 2018, consisting of Total Sales Revenue of $1,385 million on Exhibit EM-14 (RRJ-4) less Total Fuel Cost of $801 million on Exhibit EM-15 (RRJ-5).

Q. How would the $584 million affect the proposals of the Staff, ABATE, and Constellation?

A. The Staff presents two methods for determining an SRM charge. The first method does not need a subtraction. The second method does.

The first method uses the Cost of New Entry ("CONE") that MISO calculates based on a combustion turbine and is approved by the FERC. Staff witness Mr. Revere states: "In Staff's opinion, the proper cost of capacity is the Cost of New Entry (CONE), or the cost to build a combustion turbine (CT)." [Mr. Revere Direct Testimony, page 5, lines 11-13.] Mr. Revere notes that "all energy is bid into the market" and that such sales "capture what Staff could consider to be the energy related portion of capacity costs"; Staff concludes that if one is using a CT as the cost of capacity service provided, then "to remove all costs above a CT and then apply an offset which effectively, if imperfectly, does the same, would be double counting the offset." [Mr. Revere Direct Testimony, page 5, line 23, to page 6, line 2.] Staff also offers that the levelized per year cost of a CT resulting from the Company's PURPA case, U-18091, could be utilized, because "This would provide consistency in the Commission's determination of the value of capacity." [Mr. Revere Direct Testimony, page 8, lines 5-6.]

I certainly agree with this. Staff is using CONE/CT/PURPA value as a cost-of-service capacity value – not using the utility embedded costs – and so no subtraction for all energy market sales or other specified sales is needed.

The second way that Staff presents is to determine "capacity-related" costs from the utility's Cost of Service Study, using the utility's embedded costs in rates, per Section 6w(3) subparagraph (a). Here, Staff does make a subtraction for subparagraph (b), agreeing with DTE's calculation of the subtraction except for one item: "The only issue Staff takes with the calculation is the inclusion of administrative costs. The law expressly states that the revenues shall be netted against fuel costs, and does not mention administrative costs." [Mr. Revere Direct Testimony, page 8, lines 9-11.] Staff subtracts $44,194 (000) from Staff's calculation of DTE's embedded costs, for the subparagraph (b) items, as shown on Exhibit S-1.1.

Q. Do you agree with this subtraction?

A. I agree that a subtraction is required. However, for the reasons I have explained previously, the subtraction should be for "all energy market sales" as stated in Section

6w(3)(b), not just the portion of energy that is "above the use of the Company's customers." Again, the Commission is implementing a statute, not revising it.

In his Exhibit S1.1, on the third line, Mr. Revere shows a subtraction of $44,194 (000). as part of the determination of a capacity-related cost number on the fourth line of $769,620 (000). I recommend that the Commission replace the $44,194,000 with a subtraction of $584,000,000, which Energy Michigan witness Mr. Jennings has determined is the appropriate value for sales revenue less fuel costs. This results in a cost of $229,814,000 or about $58 per MW-day (= $229,814,000 /10839 MW / 365).

Q. How would the $584 million affect ABATE's proposal?

A. ABATE's proposal is similar to Staff's second method, using the utility's embedded costs as the basis for determining "capacity-related generation costs." ABATE makes no subtraction for energy sales, so such a subtraction should be included in its calculation.

On pages 1 and 2 of ABATE witness Mr. Dauphanais's Exhibit AB-2 (JRD-2), capacity-related costs are shown on line 7, column (A) as $1,725,790 (000), less the energy allocator on line 9 of $431,448 (000) for a resulting recommended capacity-related number of $1,294,343 (000). Mr. Jennings's determination of "all energy market sales" and other sales, net of fuel, of $584 million, should be subtracted, resulting in a SRM charge cost of $710,343 (000). This is equivalent to about $180 per MW-day (= $710,343,000 / 10839 MW / 365).

Q. How would the $584 million affect Constellation's proposal?

A. Constellation has two approaches – one is the determination of capacity-related costs using an "Average and Excess" analytical method, the other is a review the cost of capacity from evidence in the market.

Constellation's "Average and Excess" method of determining capacity-related costs is based on DTE's embedded costs, so a subtraction for "all energy market sales" should be included in its calculation under the provisions of Section 6w(3) subparagraph (b). On page 27 of his testimony, Table 1, column (c), Constellation witness Dr. Makholm shows a capacity-related allocated amount of $887,810 (000). This is a determination of capacity-related costs from the embedded costs in DTE's rates, and so would comport with Section 6w(3) subparagraph (a). Therefore, Mr. Jennings's $584 million – the subparagraph (b) amount – should be subtracted from this, resulting in $303,810 (000), equivalent to about $77 per MW-day. Again, this is to maintain the "deal" of PA 341.

On pages 30-31 of his direct testimony, Dr. Makholm checks the reasonableness of his SRM charge determination based on two visible indicators: MISO CONE of approximately $260 per MW-day, and Consumers Energy's RFP for demand side ZRCs, where only responses at or below $164 per MW-day were picked. As explained previously for cost-of-service methods not based on the utility's embedded costs, no subtraction for "all energy market sales" is needed.

Q. The resulting amounts from several of the above methods that include the subtraction for "all energy market sales" are low compared to DTE's proposals. Do you understand why?

A. The differences in perspective here are differences among (1) a traditional capacity rate that could be charged to customers based on DTE's embedded costs, where "capacity" is valued by DTE's traditional embedded cost method, and (2) other methods that adjust for "capacity related" extractions from embedded costs, and (3) the "deal" under PA 341.

Q. Would you summarize the outcomes when the subtractions for "all energy market sales" and other sales are applied?

Outcomes of the SRM charge from Section 6w(3) subparagraphs (a) and (b) are shown in Exhibit EM-16 (AJZ-~~6~~7). Column B shows the equivalent $ per MW-day. Column C identifies the source of the proposal. Column D identifies whether or not the proposal is based on DTE's embedded costs. Column E identifies how the subtraction for Section 6w(3) subparagraph (b) is applied.

Again, PA 341 is not the result of a careful rate design, but rather a settlement from 18 months of arguing and negotiating. Specification of the charging method changed over time. We don't know what the parties involved foresaw as the ultimate outcome after the final bill was enacted. The outcome as determined by law – not by rate design – is something the Commission will have to assess.

Q. Would any of the above outcomes be suitable as an SRM charge?

A. The numbers alone are insufficient. A charge has to be applied to a specified quantity under specified circumstances, and the result must be just and reasonable and in accordance with costs of service. Energy Michigan has a single proposal for an SRM charge in two parts, as explained in my direct testimony and as shown in Exhibit EM-16 (AJZ-~~6~~7). The first part applies to all LSEs as a sharing of the cost of new local resources acquired by DTE. Beyond that, all LSEs are able to use any resource allowed by MISO, including the capacity auction, to demonstrate sufficient capacity under PA 341, as PA 341 allows. The second part of the charge applies to any capacity requirements that the LSE has not satisfied in its demonstration with resources that MISO allows.

The SRM charges proposed by other parties have to be attached to something, and that something has not been clearly identified and quantified in their filings.

Further, the SRM charge has to be used to provide some service of benefit to the AES. As explained in my direct testimony, DTE may not have the ability under the MISO tariff to take on the responsibility for and the cost of providing capacity for AESs that are deemed deficient under PA 341. The Commission will have to decide not only on the method of determining the SRM charge, but also on how that charge will be applied.

Finally, the Commission will have to harmonize the requirements of setting an SRM charge – a rate – derived from Section 6w (3) of PA 341 with a rate derived from the cost of providing service under MCL 460.11(1).

Q. Does this conclude your testimony?

A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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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.	)	
	)	

CORRECTED DIRECT TESTIMONY & EXHIBITS

OF RALPH C. SMITH

ON BEHALF OF

ENERGY MICHIGAN, INC.

DIRECT TESTIMONY OF RALPH C. SMITH
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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.

RALPH C. SMITH
DIRECT TESTIMONY

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.

RALPH C. SMITH
DIRECT TESTIMONY

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. __Capacity Costs__

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. The 75-0-25 Production Cost Allocator

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, and 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~~ 5, 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. Energy Market Sales Revenue, Off-System Energy Sales Revenue, and Ancillary Service Revenue, Net of Related Fuel Costs

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. Net Capacity Cost

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. ***<u>DTE's Owned and Purchased Capacity in MW</u>***

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. ***<u>Calculation of the State Reliability Mechanism Capacity Rate</u>***

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.	)	
______________________________________	)	

TESTIMONY & EXHIBITS OF

RUPERT R. ("ROB") JENNINGS

ON BEHALF OF

ENERGY MICHIGAN, INC.

DIRECT TESTIMONY OF RUPERT R. JENNINGS
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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.

RUPERT R. JENNINGS (ROB)
DIRECT TESTIMONY

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.

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STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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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.	)	
	)	

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.

LAEL E. CAMPBELL
DIRECT TESTIMONY

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.

JUDGE EYSTER: Mr. Pattwell.

MR. PATTWELL: Thank you, your Honor. In this case ABATE filed the direct testimony of James Dauphinais, consisting of a cover page, a Table of Contents, 35 pages of testimony, and Appendix A, consisting of five pages of qualifications, and three exhibits, AB-1, AB-2, and AB-3. Also, ABATE filed the rebuttal testimony of Mr. Dauphinais, consisting of a cover page, a Table of Contents, and seven pages. At this time, pursuant to the stipulation of the parties, I move the direct and rebuttal testimony just mentioned to be bound into the record, and that the exhibits be admitted.

JUDGE EYSTER: Any objections?

Hearing none, the testimony is bound in and the exhibits are admitted.

(Testimony bound in.)

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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 and Exhibits of

James R. Dauphinais

On behalf of

Association of Businesses Advocating Tariff Equity

July 21, 2017

BRUBAKER & ASSOCIATES, INC.

Project 10380

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**

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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 JAMES R. DAUPHINAIS

I. INTRODUCTION AND SUMMARY

Q Please state your name and business address.

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

Q What is your occupation?

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

Q Describe your educational and professional background.

A I hold an Associate's Degree in Electric Engineering Technology from Hartford State Technical College, a Bachelor's Degree in Electrical Engineering from the University of Hartford, and have completed graduate level courses in the study of power system transients and power system protection through the Engineering Outreach Program of the University of Idaho. For the first 12 years of my career, I was employed in the Transmission Planning Department of the Northeast Utilities Service Company ("NU," now "Eversource"), where I was extensively involved with transmission planning, transmission operation and transmission open access issues.

For the past 20 years I have been employed by Brubaker & Associates Inc. During these 20 years I have been engaged with respect to resource planning, transmission planning, wholesale power market structure, market power, transmission access, transmission line routing, fuel cost, power procurement and rate issues throughout the United States and Canada. For at least 18 of these 20 years, I have participated in the Midcontinent Independent System Operator, Inc. ("MISO") stakeholder process on behalf of various large end-use customer groups. This work has included, but not been limited to, providing extensive feedback to MISO and other MISO stakeholders regarding the design of MISO's day-ahead and real-time energy markets and MISO's current Resource Adequacy Requirements ("RAR") construct, including its annual prompt Planning Resource Auction ("PRA") for capacity. This work has included active participation in the MISO Resource Adequacy Subcommittee (including its predecessor, the MISO Supply Adequacy Working Group ("SAWG")), and the MISO Loss of Load Expectation Working Group ("LOLEWG"). I have testified before the Federal Energy Regulatory Commission ("FERC") as well as many state and provincial regulatory commissions. Appendix A to my testimony provides additional information on my background and experience.

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

A Yes. Over the past 20 years, I have provided testimony to the Commission on several occasions regarding issues that include, but are not limited to, electric rate design, class cost of service, power supply cost recovery, standby service rates, transmission planning, and transmission line routing.

Q On whose behalf are you appearing in this proceeding?

A I am appearing on behalf of Association of Businesses Advocating Tariff Equity ("ABATE"), a group of businesses including many of Michigan's largest employers and energy users. ABATE's members include both bundled retail and retail open access ("ROA") electric customers of DTE Electric Company ("DTE" or "Company").

Q What is the purpose of your direct testimony?

A I respond to DTE's proposal in this proceeding for its State Reliability Mechanism ("SRM") Capacity Charge and DTE's proposals in this proceeding with respect to the application of its SRM Capacity Charge to its bundled retail and ROA customers. Pursuant to the Commission's March 10, 2017 and May 11, 2017 Orders, which direct interested parties to comment on capacity obligation and demonstration issues in U-18197, I have refrained from addressing capacity obligation and demonstration issues unless necessary to comment on DTE's proposed SRM Capacity Charge. If a specific issue is not addressed in my testimony, it should not be construed as an endorsement of DTE's position on that issue or a waiver of any argument regarding the legality of either Section 6w of

Public Act 341 ("Section 6w") or any subsequent order of the Commission implementing Section 6w.

Q Please summarize your conclusion and recommendation in this proceeding.

A My conclusions and recommendations are as follows:

1. DTE's proposal to include both the 75% 4 CP demand and 25% total annual usage energy allocation of fixed generation costs in its SRM Capacity Charge should be rejected. Capacity in the MISO market does not include the provision of energy at a given price and ROA customers are not permitted to benefit under ROA from the average fuel cost of DTE's generation facilities and/or purchased power agreements. In order to gain energy price protection, ROA customers have to either enter into fixed energy price arrangements with their AES or, alternatively, use financial instruments such as swaps to manage their energy price risk. Both of these alternatives typically require ROA customers to pay either explicit or implicit risk premiums in order to obtain that price certainty. For all of these reasons, DTE's SRM Capacity Charge should exclude the 25% total energy usage allocated portion of DTE's fixed generation costs.
2. The way DTE calculates its proposed SRM Capacity Charge assumes no ROA customers will actually pay its SRM Capacity Charge. DTE's assumption in this regard is unreasonable. The way DTE calculates its SRM Capacity Charge will cause DTE to over recover its capacity costs if it provides any capacity to ROA customers since its incremental cost to provide capacity to ROA customers will be approximately half of its current average embedded cost for capacity. To address this issue, the Commission should require DTE to make a filing after the February 2018 SRM capacity demonstrations by AESs and the conclusion of DTE's general rate case in Case No. U-18255 to update its SRM Capacity Charge to reflect the additional capacity costs DTE has incurred to supply capacity to ROA customers and the billing units of the ROA customers taking that capacity.
3. DTE's proposal to true-up the SRM Capacity Charge as required under Section 6w(5) is ambiguous and incomplete. DTE should use a 100% demand 4CP allocation method and use a loss-differentiated charge to calculate and bill any true-up charge or credit to all retail customers.
4. DTE's proposed perpetual implementation of the SRM is unnecessary and unreasonable. Beyond the initial four year term mandated by Section 6w, the continued implementation of the SRM should be determined by the Commission on an annual basis.
5. DTE's proposed 30 year payment obligation for ROA customers for the SRM Capacity Charge is unnecessary and highly anticompetitive. The purchase

obligation should be limited to no more than a year after the initial four year term of the SRM.

6. DTE's proposal to place ROA customers paying the SRM Capacity Charge or returning to bundled retail service into a 4-year firm service queue under which these customers might have to take interruptible electric service for up to 4 years is also unnecessary and high anticompetitive. It should also be rejected by the Commission.

7. Without waiving any challenge to the legality of Section 6w and/or the Commission's June 15, 2017 interim finding that a locational requirement is purportedly required under Section 6w, ABATE, on July 17, 2017, in Case No. U-18197 filed comments with the Commission proposing that any local capacity obligation imposed by the Commission under the SRM only be placed on ROA customers for their load-ratio share of any new incremental capacity required in MISO Local Resource Zone ("LRZ" or "Zone") 7 in order for the Local Clearing Requirement ("LCR") of MISO LRZ 7 to be met. Under that proposal, the SRM Capacity Charge for any local capacity provided by DTE to its serve bundled retail and ROA customers would be charged for in a separate Local SRM Capacity Charge based on the revenue requirement for such incremental local capacity. Therefore, to the extent this incremental local capacity proposal is adopted by the Commission in Case No. U-18197, DTE's SRM Capacity Charge set in this proceeding should not apply to the provision of such incremental local capacity from DTE to its bundled retail and ROA customers.

<u>II.</u> <u>BACKGROUND ON THE SRM AND THE SRM CAPACITY CHARGE</u>

Q Please provide a brief explanation of the SRM and SRM Capacity Charge.

A The SRM is "a plan adopted by the commission in the absence of a prevailing state compensation mechanism to ensure reliability of the electric grid in this state consistent with subsection (8) [of Section 6w.]" MCL 460.6w (12)(h). Among other things, subsection (8) states "by the seventh business day of February each year, that each alternative electric supplier … demonstrate to the commission, in a format determined by the commission, that for the planning year beginning 4 years after the beginning of the current planning year, the alternative electric supplier … owns or has contractual rights to sufficient capacity to meet its capacity obligations as set by the appropriate independent system operator, or commission, as applicable." MCL 460.6w (8)(b). Subsection (8) also states that "by the seventh business day of February of 2018, an alternative electric supplier shall demonstrate to the commission, in a format to be determined by the commission, that for the planning year beginning June 1, 2018, and the subsequent 3 planning years, the alternative electric supplier owns or has contractual rights to sufficient capacity to meet its capacity obligations set by the appropriate independent system operator, or commission, as applicable." *Id.*

Q Who is the "Appropriate Independent System Operator"?

A Section 6w defines the "appropriate independent system operator" as "the Midcontinent Independent System Operator [(*i.e.*, MISO").]" MCL 406.6w (12)(a)). MISO is the FERC-regulated independent system operator and regional transmission organization that functionally controls the transmission system owned by the International Transmission Company ("ITC") that interconnects DTE and its electric customers to the remainder of the interconnected electric system in the Eastern Interconnection of the United States and Canada. In addition to functionally controlling the transmission systems of ITC and the other transmission owners within the MISO footprint, MISO administers a FERC-regulated tariff (the "MISO Tariff") that provides for unbundled transmission service and the operation of wholesale markets for electric energy, operating reserves, and capacity within the MISO footprint. Under these tariff provisions, MISO operates an hourly day-ahead and real-time energy and operating reserve market and a *voluntary* annual capacity auction known as the Planning Resource Auction ("PRA").

Q Please further explain MISO's role with respect to capacity.

Under MISO's tariff provisions for its capacity market, all Load Serving Entities ("LSEs") within the MISO market footprint must either: (i) acquire sufficient capacity, in the form of Zonal Resource Credits ("ZRCs"), through self-supply, bilateral purchases, and/or the PRA to cover the LSE's Planning Reserve Margin Requirement ("PRMR"); or (ii) pay a capacity deficiency charge. *See* MISO Tariff, Module E-1 §§ 69A, 69A.7.1 and 69A.10. ZRCs can come from a wide variety of sources including MISO-registered Generation Resources, External Resources (essentially, generations resource located outside of the MISO footprint), Behind-the-Meter Generation, Demand Resources (interruptible load), Demand Response Resources and Energy Efficiency. *Id.* §§ 69A.3.1, 69A3.2, 69A3.3, 69A.4 and 69A.5.

It is important to note that ZRCs do not provide to the holder any right to directly receive any energy from the source of the ZRC. *See* MISO Tariff, Module A at Zonal Resource Credit; MISO Tariff, Module E-1 § 69A.4.5. Instead, there is an obligation placed on the <u>source</u> of the ZRC to either offer energy into the MISO hourly day-ahead and real-time energy market (if it sourced from a Generation Resource, External Resource or Demand Response Resource) or be available for use during declared emergencies (Behind-the-Meter Generation and Demand Resources). *See* MISO Tariff, Module E-1 §§ 69A.3.3 and 69A.5. As a result, unlike with the ownership (or an entitlement to the output) of a generation facility, the possession of a ZRC provides absolutely no right to its holder to receive energy at a particular price or heat rate.

Nor do ZRCs provide the holder with any sort of hedge with respect to the market price for electric energy. While the ZRC holder (just like any other MISO market participant), would have the right to purchase electric energy from the MISO hourly day-ahead and real-time energy market, that purchase of energy would be at whatever price the market will bear within the confines of market monitoring and mitigation provisions of the MISO Tariff, Module D. Under the MISO Tariff, such market prices during scarcity hours could potentially be as high as the MISO Value of Lost Load ("VOLL") – currently $3,500 per MWh. *See* MISO Tariff, Module C §§ 39.2.9, 39.2.10 and 40.2.17; MISO Tariff, Schedule 28 § III. To address these energy market price risks, the ZRC holder would have to enter into additional transactions to either fix or hedge the market price for electric energy. Such forward looking contracts either explicitly or implicitly include risk premiums that cover the risk taken on by the provider of the fixed price or hedge.

Another alternative to fix or hedge the price would be for the holder of the ZRCs to acquire those ZRCs as part of ownership (or purchasing an entitlement to the output) of a generation resource. However, this alternative still requires premiums to be incurred above the cost of ZRCs because it requires the generator in question to forgo the opportunity to earn future profits from the MISO hourly day-ahead and energy market sales and/or forward bilateral energy sales to other market participants. It also would require the generator to forgo any energy market price protection the generator was providing to any load obligations that generator may have.

Q Does MISO impose any geographic limitations on the use of ZRCs to meet the PRMR?

A MISO does not place any geographic limitation on individual LSEs with respect to their use of ZRCs except to the extent a LSE chooses to use a Fixed Resource Adequacy Plan ("FRAP"). However, MISO has broken its footprint up into a series of Local Resource Zones ("Zones" or "LRZs") and imposes a Local Clearing Requirement ("LCR") on each of the those Zones when it runs its annual PRA. *See* MISO Tariff at Attachment VV and MISO Tariff, Module E-1 §§ 69A and 69A.7. The LCR is based on the ZRCs that would be required for that Zone if it were an island less the amount of capacity that can be imported into that Zone (the Capacity Import Limit ("CIL")) adjusted for non-pseudo-tied exports of capacity from the Zone to markets outside of MISO. *See* MISO Tariff, Module E-1 §§ 68A.5 and 68A.6. If the LCR binds for a zone, it will result in a higher auction clearing price for ZRCs in that zone as compared to neighboring zones. If an LSE in that zone used ZRCs from neighboring zones to meet its PRMR, it is either implicitly or explicitly subject to a transmission congestion charge in the capacity market called a Zonal Delivery Charge ("ZDC") set equal to the difference in price between the LSE's PRMR Zone and the Zone where its ZRCs are located. *Id.* §§

69A.7.6 and 69A.7.8.[1] This charge could be as high as the MISO Cost of New Entry ("CONE"), which for the 2017-2018 planning year was $260 per MW-day.

It should also be noted that there are other transmission limitations besides the LCR for each Zone that could lead to an LSE implicitly or explicitly incurring ZDCs. These include the Capacity Import Limit ("CIL") for each Zone, the Capacity Export Limit ("CEL") for each Zone, and the sub-regional constraint to and from the Arkansas/Louisiana/Mississippi/Texas portion of MISO, which is collectively known as MISO South. *Id.* §§ 68A.3.1, 68A.4, and 69A.7. However, the transmission limitation most relevant to the SRM is the LCR for MISO Zone 7 (the Lower Michigan portion of MISO) as it drives how much local capacity MISO must attempt to acquire in that Zone in the PRA.

Q What is a FRAP and what geographic limitation on the use of ZRCs is placed upon an LSE by MISO when using a FRAP?

A A FRAP is an option available to LSEs who would like to entirely remove themselves from the PRA. They directly specify to MISO the ZRCs they would like to use to meet their PRMR. *Id.* §§ 69A.9. If a LSE uses a FRAP, it may not specify ZRCs located outside of the Zone of its PRMR in excess of its load ratio

[1] LSEs using a FRAP are explicitly subject to a ZDC under the MISO Tariff (Section 69A.7.6). LSEs who self-schedule ZRCs into the PRA are implicitly subject to a ZDC in that MISO charges them the Auction Clearing Price of the Zone where their PRMR is located and credits them the Auction Clearing Price of the Zone where there ZRCs are located. As a result, when self-scheduling ZRCs, an LSE on a net basis pays MISO the difference in price between the LSE's Zone for its PRMR and the Zone where its ZRCs are located, which is the same as the ZDC between the two Zones when the PRMR Zone has a higher Auction Clearing Price than the ZRC Zone.

share of the effective import capability into that Zone. *Id.*[2] The effective import capability of a zone is the difference between the total PRMR for that Zone and the LCR for that Zone. No LSE is required to use a FRAP. LSE's who are providing ZRCs through self-supply or bilateral contracts can either use the FRAP or self-schedule their ZRCs into the PRA. Under self-scheduling, the ZRCs are offered into the PRA at an offer price of zero, which guarantees they will clear in the PRA and cover the LSE's PRMR. *See* MISO Tariff, MISO Module E-1 § 69A.7.8.

Q Please briefly explain the "capacity obligations" that must be met by an AES?

A As I noted earlier, the capacity obligation of an AES is "set by the appropriate independent system operator [(*i.e.*, MISO)], or commission, as applicable." MCL 460.6w(8)(b). Section 6w(8)(c) further specifies that "[i]n order to determine the capacity obligations, [the commission shall] request the appropriate independent system operator provide technical assistance in determining the local clearing requirement and planning reserve margin requirements." MCL 460.6w(8)(c). "If the appropriate independent system operator declines, or has not made the determination by October 1 of that year, the commission shall set any required local clearing requirement and planning reserve margin requirement, consistent with federal reliability requirements." *Id.*

[2] The MISO Tariff technically requires the LSE's load ratio share of the LCR to be met with local ZRCs. However, because LSEs can use a FRAP for all, some or none of their PRMR, in actual practice, MISO, instead of requiring a certain amount of local ZRCs be designated in the FRAP, limits the amount of non-local ZRCs a LSE can designate in a FRAP to a load ratio share of the difference between the Zone's total PRMR and the Zone's LCR. Assuming a LSE uses a FRAP for its entire PRMR, limiting that LSE's designation of non-local ZRCs to a load ratio share of the difference between the Zone's total PRMR and the Zone's LCR produces the same outcome as requiring the LSE to designated local ZRCs for a load ratio share of the ZRC.

Section 6w(8)(d) also indicates that "[i]n order to determine if resources put forward will meet such federal reliability requirements, [the commission shall] request technical assistance from the appropriate independent system operator to assist with assessing resources to ensure that any resources will meet federal reliability requirements." MCL 460.6w(8)(d). "If the technical assistance is rendered, the commission shall accept the appropriate independent system operator's determinations unless it finds adequate justification to deviate from the determinations related to the qualification of resources." *Id*. Finally, Section 6w(8)(d) indicates that "[i]f the appropriate independent system operator declines, or has not made a determination by February 28, the commission shall make those determinations." *Id.*

Q What are "Federal Reliability Requirements"?

A The "federal reliability requirements" in Section 6w are undefined.

Q Assuming the MISO Tariff LCR and PRMR constitute the "Federal Reliability Requirements" referenced in Section 6w, how would they be met?

A As I have discussed, pursuant to the MISO Tariff, from ZRCs sourced from Generation Resources, External Resources, Behind-the-Meter Generation, Demand Resources, Demand Response Resources and Energy. However, it should be noted that MISO does not currently have in place provisions to register resources and create ZRCs from them for any planning years beyond the next planning year.

Q What happens if an AES does not demonstrate to the Commission that it meets its capacity obligations under the SRM?

A The Commission shall "[f]or alternative electric load, require the payment of a capacity charge that is determined, assessed, and applied in the same manner as subsection (3) [of Section 6w] for that portion of load not covered." MCL 460.6w (8)(b)(i). This "capacity charge" is what I refer to as the SRM Capacity Charge.

Q Does Section 6w describe how the SRM Capacity Charge is to be calculated?

A Somewhat. Section 6w(3) states that "[i]n order to ensure that non-capacity 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. [MCL 460.6w (3).]

In addition, Section 6w(4) requires the Commission to provide for an annual true-up mechanism "that results in a utility charge or credit for the difference between the projected net revenues described in subsection (3) and the actual net revenues reflected in the capacity charge." MCL 460.6w(4). Similarly, Section 6w(5) provides that "[n]ot less than once every year, the commission shall review or amend the capacity charge in all subsequent rate cases, power supply cost recovery cases, or separate proceedings established for that purpose." MCL 460.6w(5).

Q But does Section 6w define "capacity-related generation costs"?

A No, it does not. However, assuming the MISO Tariff resource adequacy requirements are the "federal reliability requirements" and given that capacity means ZRCs under the current MISO resource adequacy requirements, the SRM Capacity Charge should exclude utility generation costs that are not associated with providing ZRCs since it is only ZRCs that are being provided to ROA customers that are subject to the SRM Capacity Charge. These ROA customers will not receive any energy from their utility. To receive energy from their utility, they would have to return to being bundled retail customers of the utility.

III. DTE'S PROPOSED SRM CAPACITY CHARGE

Q Please summarize DTE's proposed SRM Capacity Charge.

A DTE has developed its proposed SRM Capacity Charge by starting with the electric class cost of service study approved by the Commission's January 31, 2017 order in Case No. U-18014 -- DTE's last general rate case ("Approved COSS"). *See* Lacey at 4. The production cost allocation methodology used in the Approved COSS was a 75% 4 Coincident Peak ("CP") and 25% total annual energy usage (75/0/25) weighting methodology for production capacity and a 12 CP 100% methodology for transmission expense. *See* Commission Order in Case

No. U-18014 at 100. From this starting point, DTE created a new classification of the production revenue requirement to comply with implementation of the SRM. *See* Lacey at 5. It did so by subtracting the following costs from its total production related costs to arrive at capacity related costs: (i) projected energy sales revenue net of projected fuel costs; (ii) fuel expense, which includes transmission expense based on my review of the COSS; (iii) non-capacity related purchased power; and (iv) variable O&M . *Id.* at 5-6; Exhibit A-14.

Once DTE completed its new classification between capacity-related and non-capacity related costs, in order to develop the capacity and non-capacity power supply charges for primary rate schedules, DTE removed the non-capacity revenue requirement from the current power supply energy charges, and considers the existing power supply demand charge to be the capacity-related component of the production revenue requirement. *See* Bloch at 6-7. DTE also assumed the billing units remain the same, which means it assumed no ROA customers would purchase capacity from it under the SRM Capacity Charge. *Id.* at 8; Stanczak at 17. DTE indicates the resulting capacity charges plus non-capacity charges are equal to the power supply charges approved in Case No. U-18014 for all rate classes. *See* Bloch at 9. It also indicates that for rates that have power supply demand charges, 100% of the capacity costs are being collected in the power supply demand charges and the non-capacity costs are being collected in per kWh or volumetric charges. *Id.* at 6-7.

Q Do you have any concerns with DTE's development of its proposed SRM Capacity Charge?

A Yes. I have the following concerns:

- The proposal inappropriately classifies the 25% total energy usage allocation of fixed production costs to capacity-related costs when they are better characterized as non-capacity related costs thus inflating the SRM Capacity Charge.
- DTE's calculation of the SRM Capacity Charge assumes no ROA customers will pay it. This is unreasonable as it will allow DTE to over recover its costs where ROA customers will be paying an SRM Capacity Charge based on DTE's fully embedded cost for capacity but the actual cost of the capacity DTE will be providing to the ROA customers will be approximately half of its current average embedded cost for capacity.

A. Classification of the 25% Total Energy Allocation as Capacity Related Costs.

Q Why it is inappropriate to classify the 25% total energy allocation of fixed production costs to capacity related costs?

A There are several reasons. First, as I discussed earlier, the capacity that is being provided by DTE are ZRCs that are necessary to meet an AES's PRMR. The ZRCs provide no energy to either AESs or the ROA customers of DTE who are taking power supply service from those AESs. The ROA customers remain subject to hourly market prices for energy and do not benefit from the hedge that is provided by DTE's generation facilities to DTE's bundled retail customers against rising hourly market prices for energy. As I noted earlier, in times of scarcity, these hourly energy market prices for energy can potentially reach as high as the MISO VOLL -- $3,500 per MWh. Furthermore, these hourly energy market prices are very sensitive to swings in weather or natural gas prices as witnessed in the past following Hurricanes Katrina and Rita in mid-2000s and the Polar Vortex of the winter of 2014. Also, it should not be forgotten that 10 years ago natural gas prices were steadily rising year after year to much higher levels than they are today.

Page 1 of Exhibit AB-1 (JRD-1) provides a comparison of the MISO hourly day-ahead market price (a/k/a Locational Marginal Price or electric energy market price) for the DTE load zone, and DTE's total average generation fuel and purchased power cost. I show values beginning in 2009 after the onset of the revolution in hydraulic fracking and horizontal drilling had begun to take hold. As can be seen from this price comparison, the polar vortex event of January through March 2014 is a clear example of DTE's own average total fuel and purchased power cost, as reported for its generation fleet in the FERC Form 1, providing energy price protection for bundled service customers that is not available to ROA customers subject to day-ahead or real-time market prices. Specifically, DTE's average total fuel and purchased power expense remained nearly flat while electric energy market prices increased by over 30%. Page 2 of Exhibit AB-1 (JRD-1) compares electric energy market prices to regional market natural gas prices. It shows that electric energy market prices are largely driven by the regional natural gas prices.

Second, while ABATE has long opposed, and still opposes, the allocation of any fixed production costs on the basis of energy, the Commission in Case No. U-18014 continued to allocate at least 25% of fixed production costs on the basis of total annual energy usage. The Commission reiterated in the Final Order in that proceeding, "The Company [DTE] developed its production plant to both deliver energy and provide capacity at the lowest overall cost to all customers who use the system." *See* June 15, 2015 Order in Case No. U-17689 at 21-22, as quoted in January 31, 2017 Order in Case No. U-18014 at 100. Furthermore, it cannot be reasonably denied that the basis of this allocation is not at least partially based on the belief that a portion of fixed production costs should be allocated on the basis of energy because additional cost was incurred by a utility to provide energy at a lower variable cost by investing in base load or intermediate generation facilities rather than peaking generation facilities. Therefore, to the extent a portion of fixed generation costs continues to be allocated on an energy basis, the Commission should be consistent in recognizing that the energy allocated portion of fixed production costs is not a capacity-related cost.

Finally, the very large difference between the MISO CONE value of $286.17 per MW-day,[3] which is based on the amortized cost of a new frame simple-cycle natural gas-fired combustion turbine generation facility, and DTE's proposed transmission level Rate D11 SRM Capacity Charge of $519.12 per MW-day[4] strongly suggests that DTE's fixed production costs contain significant non-capacity related costs that are a result of base load generation investments and other legacy costs that are not related to providing resource adequacy. The Commission recognized this fact in DTE's last base rate case when approving the

[3] This figure is based on $260 per MW-day grossed up for the current MISO PRA transmission loss factor of 2.1% for DTE and the current MISO planning reserve margin factor of 7.8%.

[4] DTE has proposed a Rate D11 SRM Capacity Charge of $15.79 per kW-month. (See Exhibit A-11, Schedule 2 at page 24.) Assuming a typical transmission level Rate D11 customer has a year-round coincidence factor of 100%, this can be converted to the $ per MW-day units used by MISO as follows: $519.12 per MW-day = $15.79 per kW-month x 12 months per year x 1,000 kW per MW / 365 days per year.

70/0/25 allocation methodology, writing "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." *Id.* January 31, 2017 Order in Case No. U-18014 at 100.

Q But do DTE's generation facilities contribute to lower hourly market prices that there otherwise would be?

A No. It is important to recognize that MISO's hourly market prices for energy are set based on the highest priced energy offer necessary to meet demand in a given hour – not the average of all of the energy offers accepted by MISO for that hour. Therefore, hourly market prices for energy by definition will always exceed the average cost to produce energy in that hour and purchasers of energy from MISO's spot energy market will never be able to access energy at DTE's average cost to produce energy.

Q Section 6w(3)(b) requires certain energy sales be deducted when determining capacity related costs but please explain why that mere deduction does not ensure that ROA customers paying the SRM Capacity Charge receive the same energy benefit from DTE's generation facilities as DTE's bundled retail customers?

A Because even if DTE has significant energy market sales or other energy sales that provided net revenues in a given year, the energy benefit of DTE's generation facilities would still go first and foremost to its bundled retail customers. This is because: (i) DTE can only make such wholesale energy sales from its economic generation that is available in a given hour in excess of that which it needs to service its bundled retail customers in that hour; and (ii) DTE is required to assign its lowest fuel cost generation to its bundled retail customers first prior to assigning any fuel costs to energy market sales.

Q What do you recommend the Commission do to address this issue?

A I recommend that the Commission require DTE to revise its classification of production costs between capacity-related and non-capacity related costs such that the 25% of fixed production costs that is allocated on an annual total energy usage basis is classified as a non-capacity related production cost. This would recognize that this energy allocated cost is not associated with providing resource adequacy and is instead associated with providing energy costs savings to bundled retail customers or instead associated with recovery of other legacy costs not associated with providing resource adequacy. My Exhibit AB-2 (JRD-2) shows how this recommend change in the classification of fixed production costs would affect DTE's proposed SRM Capacity Charge for Rate D11 customers. Using the same class allocation factors that DTE relied on, Exhibit AB-2 (JRD-2) removes the 25% energy allocated amount from the total capacity-related cost, and reduces DTE's proposed SRM Capacity Charge by the percentage that is the class energy allocated amount divided by the class total production capacity-related amount originally proposed by DTE. Page 1 of Exhibit AB-2 (JRD-2) shows the rate calculations for Primary Rates D11, D6.2 and D8 customers, and page 2 shows the adjusted rates for Secondary Rates D3, D3.2 and D4 customers. These classes represent the largest classes of ROA customers. Similar calculations would be performed for the remaining seven smaller classes of ROA customers.

Q Would your recommendation cause retail customers (full service load) to pay a different capacity charge than ROA customers (alternative electric supplier load)?

A No. The same SRM Capacity Charge would apply to bundled retail customers and ROA customers subject to the SRM Capacity Charge. All my recommendation does is ensure that the SRM Capacity Charge does not include DTE's non-capacity related fixed production costs that are currently allocated to rate classes on a total annual energy usage basis.

B. ROA Customer Billing Units

Q Please explain your concern with DTE's proposal to base its SRM Capacity Charge on the assumption that no ROA customers will pay it.

A Under its proposed SRM Capacity Charge, DTE will collect revenue from the ROA customers paying the SRM Capacity Charge well in excess of DTE's incremental cost to provide capacity to those customers. DTE indicates that to provide capacity to ROA customers paying the SRM Capacity Charge it could build, develop, or acquire new capacity. *See* Wojtowicz at 12. However, DTE also admits it may need to acquire that capacity from the MISO PRA. *Id.*

Furthermore, since DTE would only be providing ZRCs to ROA customers paying the SRM Capacity Charge but would not be providing energy to those ROA customers paying the SRM Capacity Charge, it is important to recognize that even if DTE built new generation to serve those customers, it would only need to be peaking generation not intermediate or base load generation. As a result, the incremental cost (*i.e.*, the per unit additional cost) to provide capacity to ROA customers paying the SRM Capacity Charge could be as low as the 2017-2018 MISO PRA Auction Clearing Price of $1.50 per MW-day or as high as the amortized cost of new frame simple-cycle natural gas turbine generation of $260 per MW-day ($286.17 per MW-day when grossed up by the applicable MISO transmission loss and planning reserve margin factors) -- the MISO CONE price -- the highest Auction Clearing Price possible in the MISO PRA. Also, the latest PPAs that Consumers Energy Company, who like DTE is located in MISO Zone 7, has proposed enter into in order to acquire ZRCs to serve its bundled retail customers have an average per unit price of $138.20 per MW-day.[5]

As I noted earlier, above, the CONE price to provide ZRCs for a transmission level Rate D11 customer with a year-round coincidence factor of 100% would be $286.17 per MW-day, but the SRM Capacity Charge DTE proposes to charge such a Rate D11 customer would be $519.12 per MW-day. As a result, I estimate for every MW of ROA customer load paying the SRM Capacity Charge, DTE would over-recover its incremental cost by at least $85,027 (81.4%) on an annual basis.[6] So, for example, if 100 MW of transmission level Rate D11 ROA load paid the SRM Capacity Charge, I estimate DTE would over-recover its incremental cost to provide capacity to those customers by at least $8.5 million,

[5] *See* Case No. U-18382, Direct Testimony of Consumers witness Ronk at Page 1 of 2 of Exhibit A-5 (DFR-5), which reports $50,442.86 per MW-year for MISO planning year 2018-2019. $138.20 per MW-day = $50,442.86 per MW-year / 365 days per year.

[6] $85,027 = 1 MW x 365 days x ($519.12 per MW-day - $286.17 per MW-day).

annually. If the incremental capacity cost turned out to be less than CONE, the over-recovery would even be greater.

Q Has DTE proposed a reasonable approach to address this inequity?

A No. DTE proposes to address the issue through the Company's general rate cases, PSCR cases, or the annual review and amendment of the DTE's SRM Capacity Charge. *See* Stanczak Direct at 20. However, this proposal does not address the issue in a reasonable manner. DTE proposed annual review and amendment process, while updating the initial SRM Capacity Charge prior to June 1, 2018, would not update the ROA customer billing units for the SRM Capacity Charge as it would rely upon the most recent base rate cases, PSCR filings, and decisions. *See* Dennis at 4 and Exhibit A-16. Furthermore, like in this current proceeding, DTE in its general rate case proceeding, Case No. U-18255, also assumes no ROA customers pay the SRM Capacity Charge. Finally, the true-up process DTE is proposing for capacity-related costs would not correct the situation until reconciliations are flowed back to customers -- a process that would not result in customer refunds until 2021. Line 9 of Exhibit A-16 indicates the first true-up of 2018 capacity related net revenues in 2020, with a true-up rate effective date of January 1, 2021.

Q What do you recommend to the Commission with respect to this issue?

A I recommend the Commission require DTE to make a filing with the Commission after the February 2018 AES SRM capacity demonstrations are made and a Final Order is issued in DTE's general rate case in Case No. U-18255. The filing should update the SRM Capacity Charge to reflect the actual ROA customer SRM

Capacity Charge billing units and DTE's actual incremental cost to provide capacity to these customers. Exhibit A-16, line 3 indicates that DTE may file on January 1, 2018 for an update to its SRM charge effective June 1, 2018, but the date of this filing would be too early to reflect the expected ROE customer SRM Capacity Charge billing units that would be filed in February 2018.

IV. TRUE-UP AND ANNUAL REVIEW OF SRM CAPACITY CHARGE

Q How does DTE propose to address the true-up mechanism required under Section 6w(4) and the annual review and amendment of the SRM Capacity Charge under Section 6w(5)?

A For the true-up and annual review and amendment, to use a combination of the Power Supply Cost Recovery ("PSCR") process, the general rate case process, and a yet to be established annual standalone process. *See* Dennis at 3-6. DTE has outlined in Mr. Dennis' Direct Testimony and Exhibit A-16 an incomplete and ambiguous plan for annually setting and truing-up the SRM capacity charges. DTE indicates that it "believes that the PSCR reconciliation proceedings are the proper venue to determine the capacity charge true-up amount." *See* Dennis at 5, lines 16-17. But DTE has not provided testimony calculating or describing the rate design for any capacity charge true-up, or rate design for adjustments to the PSCR factor that relate to capacity-related costs recovered or recoverable through the SRM capacity demand or capacity energy charges.

Q Do you have any concerns with DTE's annual review and amendment process?

A Yes. As I noted earlier, it does not reasonably account for the change in ROA customer SRM Capacity Charge billing units especially for the first MISO planning year of the SRM Capacity Charge (June 1, 2018 – May 31, 2019) since DTE is initially assuming no ROA customers will pay the SRM Capacity Charge. As discussed earlier in my testimony, to address this issue, I am recommending the Commission require DTE to update its SRM Capacity Charge for ROA customer SRM Capacity Charge billing units and DTE's incremental cost to provide capacity to those customers after the February 2018 AES capacity demonstrations are made and after the Commission issues a Final Order in Case No. U-18255.

Further, to the extent DTE uses an energy charge to assess any true-up charge or credit to demand billed customers for the SRM capacity-related costs, this use of an energy charge would not reflect the demand-related cost causation, and it would not account for energy losses between service voltage classes of customers. I recommend instead that the true-up costs or credits for capacity-related costs delineated in Section 6w(3)(i)-(iv) be allocated to classes on a 100% demand 4CP basis, and that the charge or credit be a class-differentiated charge that appropriately accounts for loss differences between the retail classes.

Q Why do you recommend the SRM capacity cost true-up be allocated to classes on a 100% 4CP demand basis?

A A 100% demand allocation is reasonable because there are no energy costs or expenses recovered in the proposed capacity-related true-up. As I discussed earlier, the costs to be trued-up are for capacity providing ZRCs, which provide no energy benefit to customers. Approving DTE's proposal to allocate capacity-related costs on an energy basis would result in an over-allocation of costs to high load factor customers, to the benefit of lower load factor customers.

Q Why do you recommend the SRM true-up charge (or credit) be calculated as a different charge (or credit) for each rate class?

A Calculating a class-specific capacity-related charge or credit will allow for proper recognition of the different energy losses caused by the various customer classes on the system. Customers who take electric service from DTE at a higher service voltage do not impose low-voltage costs on the utility. Ignoring the different cost of energy losses imposed by different types of customers in development of tariff rates is not consistent with cost causation.

V. PROPOSED APPLICATION OF THE SRM CAPACITY CHARGE

Q Please explain your concerns with respect to how DTE proposes to apply its SRM Capacity Charge.

A I have concerns with the following: (i) DTE's proposed perpetual implementation of the SRM and SRM Capacity charge; (ii) DTE's proposal to obligate ROA customers who pay the SRM Capacity Charge to pay that charge for 30 years; and (iii) DTE's proposal to place ROA customers paying the SRM Capacity Charge or returning to bundled retail service into a 4-year firm service queue under which these customers might be required to take interruptible electric service for up to 4 years if DTE is unable to find capacity to supply these customers.

A. Perpetual Implementation of the SRM

Q Please describe DTE's proposal for perpetual implementation of the SRM and SRM Capacity Charge.

A DTE indicates that Section 6w(2) requires that the SRM have a minimum term of four years. *See* Stanczak at 5. DTE argues this is necessary so the Commission does not artificially limit its ability to ensure grid reliability in Michigan and to provide a long-term assurance to utilities that the SRM will remain in effect that will aid in their planning of generation facilities. *Id.*

Q What is your concern with this proposal?

A It is unnecessary for the Commission to decide beyond a year-to-year basis whether the SRM should continue. First, the initial four-year term is given since: (i) Section 6w(2) states that "[i]f the commission implements a state reliability mechanism, it shall be for a minimum of 4 consecutive planning years beginning in the upcoming planning year;" and (ii) Section 6w(8)(b) requires that the first capacity demonstration and SRM Capacity Charge payment commitments include the intervening three MISO planning years in addition the MISO planning year that is four years out.

However, after the first annual capacity demonstration, each annual capacity demonstration is only for one MISO planning year four years out. MCL 460.6w (8)(b). In addition, Section 6w(6) states, in part, that "[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." MCL 460.6w (6).

Given the above, there is no reason for the Commission to determine whether the SRM will continue to be implemented beyond the initial four-year term except on a year-to-year basis. The four year advance capacity demonstration provides sufficient time for the construction of new generation facilities. Therefore, the Commission can "ensure the reliability of the electric grid" with a year-to-year review of whether to further continue the SRM. Furthermore, as I will discuss in more detail below, nothing in Section 6w grants incumbent utilities the right to a revenue stream from ROA customer for more than a single planning year at a time except during the initial four-year term of the SRM.

Q What do you recommend to the Commission with respect to this issue?

A I recommend the Commission seek comments annually by September 1st with respect to continuation of the SRM with an opportunity for reply comments by September 15th. Based on those comments, the Commission could issue an order by October 15th each year with respect to whether the SRM should continue for another MISO planning year.

B. 30-Year Payment Obligation

Q Please describe DTE's proposal to apply a 30-year payment obligation on ROA customers who pay the SRM Capacity Charge.

A DTE proposes to require ROA customers to pay the SRM Capacity Charge for a term of 30 years once they first become subject to it. *See* Stanczak at 15. DTE argues that if a utility is required to provide capacity for ROA customers, the utility needs assurance that cost recovery for such capacity will be sufficient to recover all of the costs for that capacity. *Id.* DTE claims this requires recovery over 30 years. *Id.* It also claims the 30-year term would treat ROA customers who pay the SRM Capacity Charge similarly to bundled customers and it is consistent with MCL 460.6w. *Id.*

Q Please explain your concerns with this proposal.

A The proposal is unnecessary, highly anticompetitive, and conflicts with the language of MCL 460.6w. The language of MCL 460.6w, as understood in the context of energy industry custom and practice, does not provide a monopoly over the provision of capacity to ROA customers once they start paying the SRM Capacity Charge. Instead, the SRM establishes an annual requirement for AES, utilities, and others to demonstrate that it "owns or has contractual rights to sufficient capacity to meet its capacity obligations . . . ." MCL 460.6w(8)(b). Moreover, as I have also noted above, "[a] capacity charge shall not be assessed <u>for any portion of capacity obligations for each planning year</u> 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." MCL 460.6w(6) (emphasis added).

DTE's proposal would essentially create an unreasonable "cliff," where once a AES falls over it, the ROA customer to whom the AES was providing power supply service becomes a captive capacity customer of DTE for 30 years. In addition, contrary to DTE's claims, the proposal does not treat ROA customers and bundled retail customers similarly. While bundled retail customers would also pay the SRM Capacity Charge, they can at any time move to ROA service; provided room opens up under to 10% ROA cap for them to do so.

Q What do you recommend the Commission do to address this issue?

A I recommend the Commission reject DTE's proposed 30-year payment obligation and clarify that ROA customers are only subject to SRM Capacity Charges for a year at a time except as provided for in Section 6w (8)(b)(i) for the initial four year term of the SRM.

C. DTE's Proposed Firm Service Queue Proposal

Q Please explain DTE's firm service queue proposal.

A If DTE cannot procure sufficient capacity to provide firm service to ROA customers electing to pay the SRM Capacity Charge or return to bundled retail service, then DTE would establish a firm service queue and customers would be placed on interruptible service until firm service is available for up to four years. *See* Bloch at 10. DTE's reasoning behind the proposal is that DTE is already projecting it will be short 200-300 MW for the MISO 2018-2019 Planning Year even if it does not provide capacity to any existing ROA customers and it is concerned that there may not be enough capacity available in the market to supply all of the existing ROA customers for which it may have to provide capacity. *See* Stanczak at 10-12; Wojtowicz 10-14.

Q What is your concern with this proposal.

A It is highly anticompetitive and unnecessary. The proposal will act as a scare tactic in that it will unnecessarily threaten existing ROA customers with the possibility of being forced onto interruptible service unless they return to taking bundled retail electric service from DTE prior to December 31, 2017. Most of these customers likely cannot tolerate taking interruptible electric service due to safety or other important concerns.

Whether a ROA customer returns to bundled electric service before December 31, 2017, returns to bundled retail service after December 31, 2017 or remains under ROA and pays the SRM Capacity Charge, DTE will have the obligation to obtain ZRCs in order to provide capacity to that customer and will face the same challenge to obtain capacity for the 2018-2019 MISO Planning Year. Furthermore, this is no different than if DTE picks up an entirely new bundled retail customer. It must obtain capacity for that customer and it will contribute to the same challenge to obtain capacity for the 2018-2019 Planning Year. Nothing in MCL 460.6w permits DTE to force any of these customers to take interruptible electric service. Moreover, the only purpose that would be served by DTE's proposal would be to drive ROA customers back to taking bundled retail service from DTE, which would be clearly anticompetitive and counter to MCL 460.6w, which did not end ROA.

In addition, DTE has exaggerated the risk with respect to it not being able to obtain sufficient capacity for the MISO 2018-2019 Planning Year. First, the recently released 2017 OMS/MISO Resource Adequacy Survey (Exhibit JRD-3 (AB-3) shows that MISO Zones 2 through 7 as a whole are currently projected to have 2,700 to 4,800 MW of excess capacity (on an installed capacity basis) for the 2018-2019 Planning Year and that Zone 7 is projected to have 100 to 400 MW of capacity in excess of the LCR for Zone 7 (on a installed capacity basis). *See* Exhibit JRD-3 (AB-3) at 14 and 54. While Zone 7 will not have sufficient local capacity to cover its entire PRMR from local capacity, this shortfall will be able to be imported from MISO's projected surplus of 2,700 to 4,800 MW of capacity since only the LCR needs to be drawn from local capacity. Finally, it is important to note that even if the Zone 7 LCR was not met for the MISO 2018-2019 Planning Year, it does not mean there would be a major erosion of reliability that might justify forcing customers onto interruptible service assuming it was actually allowed under MCL 460.6w. Instead, it would mean that the likelihood of some amount of firm customer load being lost due to insufficient generation resources has increased by some limited amount from one day in ten years for that one planning year. In all likelihood, that increase would be very small and imperceptible to retail electric customers in Zone 7. It certainly would not justify forcing retail electric customers onto interruptible electric service.

Q What do you recommend the Commission do to address this issue?

A I recommend the Commission reject DTE's firm service queue proposal and clarify that DTE has an obligation to provide firm electric service to all of its retail customers who have not voluntarily elected to take interruptible electric service regardless of whether those customers are taking bundled retail service, paying the SRM Capacity Charge or have given DTE four years notice to take such service.

VI. **<u>SRM CAPACITY CHARGE FOR LOCAL CAPACITY</u>**

Q Is DTE proposing the same SRM Capacity Charge for both local and non-local capacity?

A Yes. However, as I noted at the outset of this testimony, on July 17, 2017, ABATE filed comments with the Commission in Case No. U-18197 whereby it proposed that a local capacity obligation under the SRM only be placed on ROA customers for their load-ratio share of <u>any new incremental capacity required in MISO Zone 7 in order for the LCR of Zone 7 to be met</u>. As part of this proposal, DTE would charge a separate local SRM Capacity Charge to both its bundled retail customers and ROA customers who are subject to that local SRM Capacity Charge. This local SRM Capacity Charge would be based on the revenue requirement of the incremental capacity necessary to meet the LCR of Zone 7.

Q In light of ABATE's July 17, 2017 filed comments in Case No. U-18197, what do you recommend the Commission do with respect to the SRM Capacity Charge being determined in this case?

A I recommend that the SRM Capacity Charge determined in this case not apply to the local capacity obligation of AESs and only apply to the non-local capacity obligation of AESs since under ABATE's proposal there would be a separate SRM Capacity Charge paid for local capacity.

VII. **<u>CONCLUSIONS AND RECOMMENDATIONS</u>**

Q Please briefly summarize your conclusions and recommendations in this proceeding.

A My conclusions and recommendations are as follows:

1. DTE's proposal to include both the 75% 4 CP demand and 25% total annual usage energy allocation of fixed generation costs in its SRM Capacity Charge should be rejected. Capacity in the MISO market does not include the provision of energy at a given price and ROA customers are not permitted to benefit under ROA from the average fuel cost of DTE's generation facilities and/or purchased power agreements. In order to gain energy price protection, ROA customers have to either enter into fixed energy price arrangements with their AES or, alternatively, use financial instruments such as swaps to manage their energy price risk. Both of these alternatives typically require ROA customers to pay either explicit or implicit risk premiums in order to obtain that price certainty. For all of these reasons, DTE's SRM Capacity Charge should exclude the 25% total energy usage allocated portion of DTE's fixed generation costs.

2. The way DTE calculates its proposed SRM Capacity Charge assumes no ROA customers will actually pay its SRM Capacity Charge. DTE's assumption in this regard is unreasonable. The way DTE calculates its SRM Capacity Charge will cause DTE to over recover its capacity costs if it provides any capacity to ROA customers since its incremental cost to provide capacity to ROA customers will be approximately half of its current average embedded cost for capacity. To address this issue, the Commission should require DTE to make a filing after the February 2018 SRM capacity demonstrations by AESs and the conclusion of DTE's general rate case in Case No. U-18255 to update its SRM Capacity Charge to reflect the additional capacity costs DTE has incurred to supply capacity to ROA customers and the billing units of the ROA customers taking that capacity.

3. DTE's proposal to true-up the SRM Capacity Charge as required under Section 6w(5) is ambiguous and incomplete. DTE should use a 100% demand 4CP allocation method and use a loss-differentiated charge to calculate and bill any true-up charge or credit to all retail customers.

4. DTE's proposed perpetual implementation of the SRM is unnecessary and unreasonable. Beyond the initial four year term mandated by Section 6w, the continued implementation of the SRM should be determined by the Commission on an annual basis.

5. DTE's proposed 30 year payment obligation for ROA customers for the SRM Capacity Charge is unnecessary and highly anticompetitive. The purchase obligation should be limited to no more than a year after the initial four year term of the SRM.

6. DTE's proposal to place ROA customers paying the SRM Capacity Charge or returning to bundled retail service into a 4-year firm service queue under which these customers might have to take interruptible electric service for up to 4

years is also unnecessary and high anticompetitive. It should also be rejected by the Commission.

7. On July 17, 2017, without waiving any challenge to the legality of Section 6w and/or the Commission's June 15, 2017 interim finding that a locational requirement is purportedly required under Section 6w, ABATE in Case No. U-18197 filed comments with the Commission proposing that any local capacity obligation imposed by the Commission under the SRM only be placed on ROA customers for their load ratio share of any new incremental capacity required in MISO Local Resource Zone ("LRZ" or "Zone") 7 in order for the Local Clearing Requirement ("LCR") of MISO LRZ 7 to be met. Under that proposal, the SRM Capacity Charge for any local capacity provided by DTE to its serve bundled retail and ROA customers would be charged for in a separate Local SRM Capacity Charge based on the revenue requirement for such incremental local capacity. Therefore, to the extent this incremental local capacity proposal is adopted by the Commission in Case No. U-18197, DTE's SRM Capacity Charge set in this proceeding should not apply to the provision of such incremental local capacity from DTE to its bundled retail and ROA customers.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

<u>Qualifications of James R. Dauphinais</u>

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

Q PLEASE STATE YOUR OCCUPATION.

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

Q PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I graduated from Hartford State Technical College in 1983 with an Associate's Degree in Electrical Engineering Technology. Subsequent to graduation I was employed by the Transmission Planning Department of the Northeast Utilities Service Company[7] as an Engineering Technician.

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

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

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

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

From 1990 to 1995, I also acted as an internal consultant to the Nuclear Electrical Engineering Department of Northeast Utilities. This included interactions with the electrical engineering personnel of the Connecticut Yankee, Millstone and Seabrook nuclear generation stations and inspectors from the Nuclear Regulatory Commission (“NRC”).

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

In 1997 I joined the firm of Brubaker & Associates, Inc. The firm includes consultants with backgrounds in accounting, engineering, economics, mathematics, computer science and business. Since my employment with the firm, I have filed or presented testimony before the Federal Energy Regulatory Commission in Consumers

Energy Company, Docket No. OA96-77-000; Midwest Independent Transmission System Operator, Inc., Docket No. ER98-1438-000; Montana Power Company, Docket No. ER98-2382-000; Inquiry Concerning the Commission's Policy on Independent System Operators, Docket No. PL98-5-003; SkyGen Energy LLC v. Southern Company Services, Inc., Docket No. EL00-77-000; Alliance Companies, et al., Docket No. EL02-65-000, et al.; Entergy Services, Inc., Docket No. ER01-2201-000; Remedying Undue Discrimination through Open Access Transmission Service, Standard Electricity Market Design, Docket No. RM01-12-000; Midwest Independent Transmission System Operator, Inc., Docket No. ER10-1791-000; NorthWestern Corporation, Docket No. ER10-1138-001, et al.; Illinois Industrial Energy Consumers v. Midcontinent Independent System Operator, Inc., Docket No. EL15-82-000; and Midcontinent Independent System Operator, Inc., Docket No. ER16-833-000 I have also filed or presented testimony before the Alberta Utilities Commission, Colorado Public Utilities Commission, Connecticut Department of Public Utility Control, the Florida Public Service Commission, Illinois Commerce Commission, the Indiana Utility Regulatory Commission, the Iowa Utilities Board, the Kentucky Public Service Commission, the Louisiana Public Service Commission, the Michigan Public Service Commission, the Missouri Public Service Commission, the Montana Public Service Commission, the New Mexico Public Regulation Commission, the Council of the City of New Orleans, the Oklahoma Corporation Commission, the Public Utility Commission of Texas, the Wisconsin Public Service Commission and various committees of the Missouri State Legislature. This testimony has been given regarding a wide variety of issues including, but not limited to, ancillary service rates, avoided cost calculations, certification of public convenience and necessity, cost allocation, fuel adjustment clauses, fuel costs, generation interconnection, interruptible rates, market power, market structure, off-system sales, prudency, purchased power costs, resource planning, rate design, retail open access, standby rates, transmission losses, transmission planning and transmission line routing.

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

In 2009, I completed the University of Wisconsin-Madison High Voltage Direct Current ("HVDC") Transmission course for Planners that was sponsored by MISO. I am a member of the Power and Energy Society ("PES") of the Institute of Electrical and Electronics Engineers ("IEEE"). In addition to our main office in St. Louis, the firm also has branch offices in Phoenix, Arizona and Corpus Christi, Texas.

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**

Rebuttal Testimony of

James R. Dauphinais

On behalf of

Association of Businesses Advocating Tariff Equity

August 16, 2017

BRUBAKER & ASSOCIATES, INC.

Project 10380

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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REBUTTAL TESTIMONY OF JAMES R. DAUPHINAIS

I. INTRODUCTION AND SUMMARY

Q Please state your name and business address.

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

Q What is your occupation?

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

Q Are you the same James R. Dauphinais who filed Direct Testimony on behalf of Association of Businesses Advocating Tariff Equity ("ABATE")?

A Yes, I am.

Q What is the purpose of your rebuttal testimony?

A My testimony responds to the Direct Testimonies of Michigan Public Service Commission Staff ("Staff") witness Mr. Nicholas M. Revere, Energy Michigan, Inc. ("EM") witnesses Ralph C. Smith and Alexander Zakem, and Constellation NewEnergy, Inc. ("CNE") witness Jeff D. Makholm, Ph.D. Specifically, I address the relationship between the MISO Cost of New Entry ("CONE") value and the calculated SRM charge required in Section 6w of Act 341, and the delineation between DTE's demand-related production costs and energy-related production costs. Lastly, I comment on Staff's proposed rate design for the SRM charge billed to bundled service and retail open access ("ROA") customers. The fact that I do not address an issue should not be interpreted as approval of any position taken by any other party in this proceeding.

II. REBUTTAL REGARDING MISO CONE AS SRM CHARGE

Q Please explain what the other interveners and Staff recommended with respect to the development of DTE's SRM Capacity Charge?

A Staff recommends that the SRM Capacity Charge be developed either by: (i) only including the 75% of DTE's fixed production costs that are allocated on a 4-CP, less a credit for energy sales; or (ii) setting the charge by only deeming the portion of DTE's fixed production costs that add up to the cost of new entry for a combustion turbine generation facility. (*See* Revere at 5-8.) Under the latter approach, Staff believes the portion of DTE's fixed production costs that exceeds the cost of new entry of a combustion turbine generation facility should properly be considered an energy cost. (*Id.* at 5-6.) It should be noted that under the latter approach, Staff proposes to use DTE's filed cost of new entry in its PURPA case, U-18091 rather than the MISO CONE value of $260 per MW-day. (*Id.* at 8.)

CNE recommends a DTE's SRM Capacity Charge of between $164 per MW-day and $260 per MW-day. (*See* Makholm at 6.) It essentially arrives at the upper portion of this range by concluding that the charge should be no more than the higher of: (i) the MISO CONE value of $260 per MW-day; or (ii) the excess portion of DTE's fixed production costs under an average and excess cost allocation method. (*Id.* at 5-6.)

EM proposes that DTE's SRM Capacity Charge be the MISO CONE value of $260 per MW-day. (*See* Zakem at 50-51.)

Q Please explain how you respond to these proposals?

A The common theme in all of these proposals is that DTE's cost to provide capacity to its ROA customers paying the SRM Capacity Charge is not greater than the amortized cost of new entry of a new combustion turbine generation facility. I agree with this common conclusion.

As I discussed in my direct testimony, ROA customers paying DTE's SRM Capacity Charge will not be receiving any energy from DTE. (*See* Dauphinais at 14). All that DTE will be providing to these customers is sufficient MISO Zonal Resource Credits ("ZRCs") to cover the MISO Planning Reserve Margin Requirement ("PRMR") for these customers. (*Id.* at 14.) DTE could provide these ZRCs by purchasing them from the MISO annual Planning Resource Auction ("PRA"), entering into new Purchased Power Agreements ("PPAs"), increasing energy optimization or demand response programs, and/or building new generation capacity. However, any new generation capacity used to provide ZRCs would only need to be peaking generation, not intermediate or base load generation. (*Id.* at 21-22.) As a result, DTE's per unit additional cost to provide capacity to its ROA customers paying the SRM Capacity Chare could be as low as the 2017-2018 MISO PRA Auction Clearing Price of $1.50 per MW-day or as high as the amortized cost of a new frame simple-cycle combustion turbine generation facility of $260 per MW-day ($286.17 per MW-day when grossed up by the applicable MISO transmission loss and planning reserve margin factors) – the highest Auction Clearing Price possible in the MISO PRA. (*Id.* at 22.)

While I agree that DTE's cost to provide capacity to its ROA customers paying DTE's SRM Capacity Charge is not greater than the amortized cost of new entry of a new combustion turbine generation facility, I disagree with Staff's position that DTE's fixed production costs in excess of the cost of new entry of a new combustion turbine generator are all energy-related costs and CNE's position that the use of an average and excess cost allocation method is reasonable. While investment in intermediate and base load generation facilities is one reason why DTE's production costs on a per unit basis are much greater than the amortized cost of a new combustion turbine generation facility, it is not the only reason. In particular, generational differences in the cost of construction of generation capacity, past poor investment decisions, and subsequent capital investments in environmental controls are among the other possible reasons why DTE's fixed production costs on a per unit basis exceed the amortized cost of new entry of a new combustion turbine generation facility. These other forms of legacy costs are not necessarily energy-related and may be most appropriately allocated to the bundled retail customer classes on the basis of coincident peak demand rather than energy consumption. Thus, while I agree the most appropriate way to set DTE's SRM Capacity Charge would be to base it on no more than the amortized cost of a new frame simple-cycle combustion turbine generation facility (currently $260 per MW-day), I would not agree that the remainder of DTE's fixed production costs should be allocated to bundled retail customer classes on the basis of annual energy consumption. Consistent with the 75/0/25 cost allocation of DTE's fixed production costs in DTE's last general rate case, U-18014, regardless of what value the Commission decides upon for DTE's SRM Capacity Charge, no more than 25% of DTE's total fixed production costs should be allocated to DTE's bundled retail customer classes on the basis of total annual energy consumption.

III. REBUTTAL REGARDING STAFF'S SRM CHARGE RATE DESIGN

Q Would you like to respond to Staff's proposed SRM charge rate design?

A Yes. Staff has proposed a similar rate design in the instant proceeding as it has in the ongoing Consumers Energy Company SRM Charge proceeding, Case No. U-18239. In Case No. U-18239, I took issue in my rebuttal testimony at pages 6-8 with Staff's proposed rate design as it resulted in a shift of total revenue requirements between rate classes, and such a shift is not required under Section 6w of Act 341 and should not be approved outside of a general base rate case. In the instant proceeding, the exhibits that Staff has provided do not make clear whether the resulting revenue spread between classes would be altered compared to the most recent Commission approved revenue spread. Specifically, Mr. Revere calls for a summer-only on-peak SRM demand charge for application to demand-billed customers. (*See* Revere at 12), but Exhibit S-1.5 shows Staff's proposed capacity SRM charge being applied to both summer and winter billing determinants for certain classes. (*See* Exhibit S-1.5 at 19, 24, 25.) I have calculated approximately $130 million in DTE approved revenue that isn't accounted for once applying Staff's proposed summer-only SRM demand charges to the appropriate summer-only billing determinants.

In the event Staff's final SRM rate proposal would shift this $130 million out of the rate classes to which it has been previously approved for recovery by the Commission in DTE's last base rate case, Case No. U-18014, I maintain the same opposition to Staff's proposal in this proceeding as I have presented in the Consumers 6w Case No. U-18239.

Q Would you like to comment on Staff's testimony related to reconciliation of the SRM charge, and use of the PSCR factor?

A Yes. Staff essentially supports DTE's proposal for reconciliation and true-up of the SRM charge. (*See* Revere at 13-14.) In my Direct Testimony at 24-26, I responded to DTE's incomplete and ambiguous plan for annually setting and truing-up the SRM capacity charges. DTE did not describe the actual proposed rate design for reconciliation or true-up, and to the extent DTE or Staff would propose to collect capacity-related costs through an energy charge, whether the PSCR or another factor, the energy charge would not reflect demand-related cost causation, and it would not account for energy losses between service voltage classes of customers. I therefore maintain my recommendation that the true-up costs or credits for capacity-related costs delineated in Section 6w(3)(i)-(iv) be allocated to classes on a 100% demand 4CP basis, and that the charge or credit be a class-differentiated charge that appropriately accounts for loss differences between the retail classes.

I also addressed in my Direct Testimony at 21-24 the need for a filing by DTE after the February 2018 AES SRM capacity demonstrations are made to reflect actual billing units for the period June 1, 2018 – May 31, 2019 of ROA customers purchasing capacity from DTE. I maintain my recommendation for this additional filing, as it would still be necessary under Staff's proposed SRM charge reconciliation procedure, which is essentially acceptance of DTE's proposed procedure.

Q Would you like to respond to Staff's secondary rate design proposal calling for a SRM energy charge per kilowatt-hour for all DTE customers?

A Yes, Mr. Revere indicates at page 12, lines 15-18 of his Direct Testimony that if the Commission determines that Section 6w of Act 341 requires all of DTE's customers, under all service rate classes, to pay the same uniform SRM charge, that the uniform charge must be a summer on-peak kilowatt-hour charge. I do not believe this is a reasonable rate design as it would be contrary to the Commission's historical interpretation and guidance vis-a-vis MCL 460.11 which requires rates be designed to equal cost of service, and collection of the SRM capacity costs through a uniform energy rate from all classes of customers would be contrary to the industry standard definition of rates that are equal to cost of service. In the instant proceeding, the Commission will need to provide an interpretation of Section 6w of Act 341 that is harmonized with MCL 460.11.

Q Does this conclude your rebuttal testimony?

A Yes, it does.

JUDGE EYSTER: Anything else? (No response.)

All right. That's it for the record. Thanks.

MS. DONOFRIO: I'm sorry.

JUDGE EYSTER: We're back on the record.

MS. DONOFRIO: Not done. Pursuant to Rule 103 of the Rules of Evidence, I'd like to make an offer of proof with regard to the exhibits that were not admitted.

JUDGE EYSTER: O.K.

MS. DONOFRIO: The court reporter has them, they are marked as Exhibit S -- I suppose it should be proposed Exhibit S-2, S-3, S-4, S-5, and S-6. They can either be included in that form or I can read them into the record, whichever you prefer.

JUDGE EYSTER: I think your reference to them is probably sufficient. But let's go off the record for just a moment.

(A discussion was held off the record.)

JUDGE EYSTER: We're back on the record. While we were off the record, we had some discussions with regards to offers of proof and discovery in general. Ms. Donofrio.

MS. DONOFRIO: Yes. In lieu of making a

statement as to the content of each of these substantively, which it is my understanding you wish me to indicate just the number of the discovery response in question for each one?

JUDGE EYSTER: Yeah, I believe it would be sufficient for purposes of appeal to identify the document, so you can give the date, the respondent, and the question number that was responded to. I believe that the Company would have these exhibits, and I don't know what other parties have them, but --

MS. DONOFRIO: They've been provided to --

JUDGE EYSTER: -- that way it will be clear to the Commission exactly what documents were at issue here at this hearing.

MS. DONOFRIO: With regard to proposed Exhibit S-2, that was an August 14, 2017, response of Nicholas M. Revere to DTE's question to Staff No. 2d. With regard to Exhibit S-3, that was an August 14, 2017, response of Nicholas M. Revere to DTE's discovery request to Staff No. 2e, as in Edward. Regard to exhibit, proposed Exhibit S-4, that was also an August 14, 2017, response of Nicholas M. Revere to a question, a discovery response from DTE to Staff No. 3c, as in cat. With regard to Exhibit S-5, proposed Exhibit S-5, this was also an August 14, 2017, response from Nicholas M. Revere to DTE's discovery request to Staff No. 3.4. And finally, proposed Exhibit S-6 was an August 14, 2017, response from Nicholas M. Revere to DTE's discovery request to Staff No. 3.5.

JUDGE EYSTER: Anything else for the record? (No response.)

O.K. That's it. Thanks.

(At 10:23 a.m., the hearing concluded.)

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C E R T I F I C A T E

I, Lori Anne Penn (CSR-1315), do hereby certify that I reported in stenotype the proceedings had in the above-entitled matter, that being Case No. U-18248, before Mark D. Eyster, J.D., Administrative Law Judge with Michigan Administrative Hearing System, at the Michigan Public Service Commission, 7109 West Saginaw Highway, Lansing, Michigan, on Thursday, August 31, 2017; and do further certify that the foregoing transcript constitutes a true and correct transcript of my stenotype notes.

Lori Anne Penn

Digitally signed by Lori Anne Penn
DN: cn=Lori Anne Penn, o=Metro Court Reporters, ou=Metro, email=metrostate@sbcglobal.net, c=US
Date: 2017.09.01 14:46:02 -04'00'

Lori Anne Penn, CSR-1315
33231 Grand River Avenue
Farmington, Michigan 48336

Dated: September 1, 2017