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August 24, 2012

Ms. Mary Jo Kunkle
Michigan Public Service Commission
6545 Mercantile Way
P.O. Box 30221
Lansing, MI 48909

Re: Case No. U-17032

Dear Ms. Kunkle:

Attached for paperless electronic filing is Energy Michigan's Initial Brief. Also attached is a Proof of Service indicating service on counsel.

Thank you for your assistance in this matter.

Very truly yours,

VARNUM, LLP

Eric J. Schneidewind

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cc: ALJ
parties

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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In the matter, on the Commission's own motion, to initiate a proceeding to establish a state compensation mechanism for alternative electric supplier capacity in INDIANA MICHIGAN POWER COMPANY'S Michigan service territory.	))))))	Case No. U-17032

INITIAL BRIEF OF ENERGY MICHIGAN, INC.

August 24, 2012

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INITIAL BRIEF OF ENERGY MICHIGAN, INC.

I. Introduction and Summary of Position

A. Introduction.

This Brief is filed on behalf of Energy Michigan, Inc. ("Energy Michigan") by Varnum. Failure to address any issue or position raised by Applicant Indiana Michigan Power Company ("I&M") or Intervenor Michigan Public Service Commission ("MPSC Staff") and FirstEnergy Solutions Corp. ("FES") should not be taken as agreement with that issue or position.

B. Summary of Position: I&M's SCM Proposal Does Not Follow Established Cost-Of-Service Principles And Is Discriminatory.

Unaffordable Rates

I&M and the MPSC Staff have proposed a State Compensation Mechanism ("SCM") and rates for Alternate Energy Suppliers' ("AES"s) customer capacity that are literally 50% higher than the rates which the Federal Energy Regulatory Commission ("FERC") opined "may be unjust, unreasonable and discriminatory". Make no mistake, adoption of the I&M/MPSC Staff capacity rates would clearly and undeniably end electric competition in the I&M service territory.

Discriminatory Allocation of Benefits

By simply assigning all production fixed costs to AES customers as "capacity," I&M/MPSC Staff would have AES customers pay literally the same capacity charges as a full service customer while depriving the AES customer of the full benefit of the corresponding low I&M energy rates. This occurs because standard service customers pay for and use low cost I&M energy. However, the energy freed up by AES sales is sold into the market, 20% of the revenues from that sale are diverted to I&M and the remaining 80% are shared by all standard service and AES customers on a pro rata basis. Consequently, only a small part of the sales of excess I&M energy freed up by Choice service are credited back to AES customers. This blatantly discriminatory and illegal proposal deprives AES customers of a major offset to the cost of I&M capacity.

The failure to allocate the full benefit of Off System Sales of energy "freed up" by Electric Choice service is contrary to Michigan Public Service Commission ("MPSC") case precedent and was not justified by Testimony or evidence demonstrating why existing Commission precedent mandating appropriate benefits to choice customers should be revised or abandoned. On the other hand, both FES and Energy Michigan introduced substantial Testimony and evidence demonstrating why Off System Sales should benefit Choice customers in an amount equivalent to the benefits conferred upon standard service customers.

Failure to Use Michigan Cost of Service Methods

The proposed I&M/MPSC Staff rates also illegally allocate 25% of production costs to AES customers. This is a clear violation of the Cost of Service requirements that 25% of production costs be allocated on the basis of energy consumption. AES customers consume no energy supplied by I&M, and neither I&M nor Staff introduced Testimony or evidence proving that a different form of allocation should be used or was even logical for AES customers. The failure to use established Cost of Service principles also violates MCL 460.11(6).

The resulting adverse impact on competition also violates the spirit and the letter of MCL 460.10(2) and Section 10a(1) which require the Commission to promote competition.

Two Equitable State Compensation Mechanisms

The Commission has two options to correct the inequities and illegalities contained in the I&M/MPSC Staff proposal:

1. PJM market based capacity rates.

The best solution would be to adopt the market based RPM pricing for capacity which is utilized throughout the PJM market area. This model results in a fair market price for capacity which is significantly lower than the price requested by I&M. However, the market based PJM model also allows I&M to sell low cost energy into the market and gain a very significant "profit" margin which can be used to offset claimed AES customer capacity costs. In contrast, the I&M/MPSC Staff proposal charges capacity rates to AES customers which are far above market levels while allowing I&M to sell its low cost energy into the market, keep 20% of profit and allocate the rest of the profit to standard service and Choice customers on a pro rata basis. This is clearly illegal and discriminatory since AES customers are asked to pay the same capacity rates as full service customers but get almost none of the benefit.

RPM pricing allows I&M the opportunity to earn a fair return on its capacity investment. If the utility experiences a net revenue shortfall, it may avail itself of the same opportunities and proceedings used by Detroit Edison and Consumers Energy to recover stranded costs.

2. Cost based capacity charges.

In the alternative, the Commission should establish a Michigan cost based capacity rate as follows: 1) assuming that the capacity rate requested by I&M is $588/MW-day, Off System Sales revenue caused by Electric Choice and documented in the record at

$342.20/MW-day should be subtracted; 2) since I&M illegally allocated 25% of production fixed costs to AES customers that have no energy consumption, a further reduction of $147/MW-day for this illegal allocation should take place.

These two cost based adjustments reduce the proposed I&M net capacity rate to $99/MW-day in comparison to the current RPM rate average rate over the next four years of approximately $89/MW-day.

If the Commission decides to adopt a rate higher than the above recommendations it must remember that significant damage to the market will occur. That damage can be avoided or mitigated by using authority in MCL 460.11(6) to defer and collect, at a later date, any amounts by which the adopted capacity rate exceeds the current RPM rate.

II. Background

A. History of the Case.

On February 29, 2012 the American Electric Power Service Corp. ("AEP") representing I&M, filed an Application with the FERC for approval of a formula rate template under which I&M would calculate its capacity costs (capacity compensation formula) pursuant to Section D.8 of Schedule 8.1 of the Reliability Assurance Agreement ("RAA") among Load Serving Entities ("LSE"s) in the PJM Interconnection, LLC ("PJM Region") pursuant to Section 205 of the Federal Power Act ("FPA"). AEP proposed that I&M recover $394/MW day of capacity costs from Alternate Energy Suppliers ("AES"s) in Michigan under the I&M Electric Choice Program.

The PJM capacity market provides two ways to assure adequate availability of necessary resources: the Reliability Pricing Model ("RPM") which provides capacity priced by a market process and the Fixed Resource Requirement ("FRR") which allows the LSE to submit the FRR capacity plan without participating in the RPM. Section D.8 of Schedule 8.1 of the RRA sets forth the rules of participation in the PJM capacity market and specifies circumstances under which various states or the FERC can establish compensation for capacity:

> … In a state regulatory jurisdiction that has implemented retail choice, the FRR Entity must include in its FRR Capacity Plan all load, including expected load growth, in the FRR Service Area, notwithstanding the loss of any such load to or among alternative retail LSEs. In the case of load reflected in the FRR Capacity Plan that switches to an alternative retail LSE, where the state regulatory jurisdiction requires switching customers or the LSE to compensate the FRR Entity for its FRR capacity obligations, such State Compensation Mechanism will prevail. In the absence of a State Compensation Mechanism, the applicable alternative retail LSE shall compensate the FRR Entity at the capacity price in the unconstrained portions of the PJM Region, as determined in accordance with Attachment DD to the PJM Tariff, provided that the FRR Entity may, at any time, make a filing with FERC under Sections 205 of the Federal Power Act proposing to change the basis for compensation to a method based on the FRR Entity's cost or such other basis shown to be just and reasonable, and a retail LSE may at any time exercise its rights under Section 206 of the FPA.

At the time of the AEP Application on behalf of I&M there were no active AES arrangements in the I&M service territory. Allen, 2 TR 146.

Numerous parties intervened in the AEP initiated docket including the Retail Energy Supply Association and Energy Michigan which requested to intervene and protested the AEP Application.

On April 30, 2012 the FERC accepted the I&M proposed formula rate proposal but suspended implementation for five months subject to refund. In so doing, the FERC observed that "… a preliminary analysis indicates that I&M's filing has not been shown to be just and reasonable and may be unjust, unreasonable, unduly discriminatory or preferential or otherwise unlawful." April 20, 2012 Order, Docket No. ER12-1173-000, page 7.

Relying on the above quoted provisions of the RAA, the Michigan Public Service Commission ("Commission") determined that it would initiate this docket to establish a SCM for AES capacity in I&M's Michigan service territory. The terms of the Commission Order initiating this docket specified, among other things, that "…by June 14, 2012 I&M shall file a Cost of Service based proposal in this docket for creation by the Commission of a State Compensation Mechanism for Alternate Energy Supplier capacity in its Michigan service territory. I&M's

proposal shall adhere to Michigan's specific ratemaking principles." Order of the Commission, May 24, 2012, page 4.

B. Law Governing the Case.

1. RAA requirements.

The terms of Section D.8 of Schedule 8.1 of the RAA provide that <u>where the state regulatory jurisdiction requires switching customers or the LSE to compensate the FRR entity for its FRR capacity obligation, such State Compensation Mechanism will prevail.</u> But in the absence of a State Compensation Mechanism the applicable alternative retail LSE shall compensate the FRR entity [at RPM rates] provided that the FRR entity may, at any time, make a filing with the FERC under Sections 205, etc." RAA Section D.8 of Schedule 8.1. (Emphasis supplied).

2. Michigan PA 141 of 2000.

2000 PA 141 § 10(2) the law states "The purpose of Section 10a through 10b is to do all of the following:

a. To ensure that all retail customers in this state of electric power have a choice of electric suppliers.

b. To allow and encourage the Michigan Public Service Commission to foster competition in the state in the provision of electric supply and maintain regulation of electric supply for customers who continue to choose supply from incumbent utilities."

Also, 2000 PA 141, § 10a(1) provides that "…The Commission shall issue Orders establishing the rates, terms and conditions of service that allow all retail customers of an electric utility or provider to choose an Alternate Energy Supplier".

2008 PA 286 provides at Section 11(6) that:

> The Commission shall approve rates equal to the cost of providing service to customers of electric utilities serving less than 1 million retail customers in this state. The rate shall be approved by the Commission in each utility's first general rate case filed after the passage of the amendatory act that added this section. If, in the judgment of the Commission, the impact of imposing cost of service rates on customers of a utility would have a material impact, the Commission may approve an Order that implements those rates over a suitable number of years. (Emphasis supplied).

C. The I&M/MPSC Staff SCM Proposal Must Be Considered On Its Own Merits.

The I&M proposal for a SCM is based on a Commission approved Settlement of General Rate Case U-16801. The SCM charges AES customers the full fixed cost of production and transmission facilities established in that case for standard service customers minus non-generation charges such as transmission, ancillary services and other PJM charges. Allen, 2 TR 143. I&M claims that this approach ensures that all I&M retail customers will pay the same cost based amount for capacity "no matter whether they are taking standard service from I&M or taking service from an AES". Id. I&M further proposes that all customers, both standard service and AES, receive a credit equal to a pro rata share of 80% of I&M's Off System Sales ("OSS") margins pursuant to terms in Case U-16801. Id. I&M witnesses and MPSC Staff witnesses concede that the I&M capacity charges implemented in U-16801 are based on a Cost of Service study that was supposed to assign production and transmission plant using a combined demand (75%) and energy (25%) allocation factor. Exhibits EM-5, EM-6.

The MPSC Staff also proposed capacity rates which are the same as those of I&M but for a reduction of $244,348 out of a total capacity component revenue requirement exceeding $120 million. Exhibit S-3. Thus, the Staff recommended capacity rates are based on a revenue requirement that is 99.8% of the level proposed by I&M – an indistinguishable difference. For purposes of this Brief, the Staff capacity rate proposal is treated as being virtually identical to that of I&M.

Both I&M and MPSC Staff proposals were presented as based upon a U-16801 Settlement Agreement adopted by the Commission in an Order; however, terms of that Settlement Agreement prevent the Settlement Agreement from being used or referenced in any other proceeding by I&M, Staff or the Commission. MPSC Case U-16801 Settlement Agreement, ¶ 14.

For this reason, pursuant to a ruling of the presiding Administrative Law Judge, none of the capacity rate proposals in this case offered by I&M or MPSC Staff or the studies upon which they are based may be viewed as entitled to anything other than full scrutiny which is the same as any other new proposal offered by other parties to this case. 2 TR 76-79.

III. Deficiencies of the I&M/MPSC Staff Proposals

A. The I&M and MPSC Staff SCM Proposals Eliminate All Competitive Savings And Therefore Will Eliminate Competition In The I&M Service Territory.

Energy Michigan Witness Roy Boston submitted Testimony estimating the impact of the proposed I&M/MPSC Staff capacity rates on competition. Mr. Boston made his estimate by analyzing the Cost of Service under the current capacity compensation mechanism whereby I&M Electric Choice customers ("OAD Customers") purchase energy at market rates, pay I&M for distribution service at I&M tariff rates and pay for PJM required capacity at the RPM rate (currently $19.89/MW-day). Under these conditions all five I&M OAD rates examined by Mr. Boston experienced savings ranging from 23%-37% not counting the supplier margin for profit. See attached Exhibit EM-2 (I&M Proposal) and EM-3 (Staff Proposal). However, if the capacity rates proposed by I&M and MPSC Staff are imposed, all examined rate classes experience substantial net losses ranging from 15% to 36% not counting a margin of profit for the AES. Id.

This result led Mr. Boston to conclude that implementation of the I&M or MPSC Staff proposed capacity rates would eliminate competition in the I&M service territory. Boston Direct, 2 TR 233 (I&M) and Rebuttal, 2 TR 252 (Staff). Mr. Boston's rate analyses were not rebutted by any party to this case. MPSC Staff Witness Stosik attempted to speculate that there might be some

I&M classes that experience savings or that customers might to use OAD service for reasons other than savings. Stosik Rebuttal, 3 TR 384-86. However, on cross examination it was determined that Mr. Stosik had literally no experience regarding competitive electric rates or contract provisions associated with sales agreements implementing such rates. 3 TR 387-89. Thus, Mr. Stosik's Testimony should be given no weight.

Mr. Boston's conclusion that the I&M and MPSC Staff proposals would eliminate competition were supported by FES Witness Banks, 3 TR 287-88.

B. The I&M/MPSC Staff Proposal Did Not Use Approved Michigan Cost of Service Allocation Principles.

Both I&M Witness Heimberger and MPSC Staff Witness Janssen have admitted that the basis for the cost allocation mechanism in the I&M Cost of Service study supporting the rates approved in U-16801 requires that production and transmission plant be assigned using combined demand (75%) and energy (25%) allocation factors. Exhibit EM-5 and EM-6.

However, Energy Michigan Witness Alex Zakem testified that the I&M/MPSC Staff proposals do not comply with the required allocation described above as regards Electric Choice service. Mr. Zakem explained that "Electric Choice customers do not take power supply service from I&M. Electric Choice customers do not take energy from the utility and they do not contribute to the utility's monthly peaks. As a result, under the [75%/25%] allocation principle established by the Commission, Electric Choice customers would not be allocated any of the utility's power supply costs." Zakem Direct, 3 TR 235. "Consequently if the intent of PA 286 is for all customers classes, including Electric Choice customer classes, to pay rates equal to the cost of providing service to the respective classes, then the rates Electric Choice customers pay to I&M should not include any power supply costs." Id. Also see Exhibit EM-6. I&M and MPSC Staff witness testimony provides support for Mr. Zakem's conclusions. Both Ms. Janssen for Staff and Ms. Heimberger for I&M testified that OAD customers do not, in fact, use <u>any</u> energy provided by I&M. 3 TR 410 (Janssen), 2 TR 114 (Heimberger).

While I&M has argued that it provides capacity to all customers under the FRR concept (Allen Rebuttal, 2 TR 156-57), <u>there can be no argument whatsoever that Michigan ratemaking principles require that all legitimate capacity costs be allocated 75% on the basis of demand and 25% on the basis of energy</u>. If OAD customers use absolutely no energy, at a minimum, the 25% energy allocator for Choice must equal zero. Zakem Direct, 3 TR 235.

Mr. Zakem's conclusions are buttressed by the testimony of I&M Witness Heimberger who agreed on cross examination that assignment of costs determine the production plant component and that production plant must be allocated on the 75%/25% basis. Also, as noted above, Ms. Heimberger agrees that I&M does not supply any energy commodity to AES customers. 2 TR 114.

To the extent that I&M may claim that federal standards or other standards in the RAA required that 100% of capacity be assigned to a Choice customer regardless of energy use, I&M itself has agreed that the RAA at Section D.8 does not limit Michigan in the development of its capacity charge mechanism. Allen Rebuttal, 2 TR 163.

C. The 80/20 Off System Sales Credit Proposed By I&M and MPSC Staff Is Unjust, Unreasonable And Discriminatory.

<u>The Discriminatory I&M OSS Proposal</u>

I&M proposes that net revenue from Off System Sales ("OSS") be distributed with 20% being retained by I&M and 80% being distributed among <u>all</u> standard service and Choice customers on a pro rata basis. Allen Direct, 2 TR 152. Yet, Mr. Allen admits that even if <u>total</u> I&M OSS equal exactly the same megawatt hours of Electric Choice sales, AES customers would still only get a portion of the OSS revenues equal to the proportion of their sales equal to total I&M sales. Id. <u>Even worse, if it could be shown that the total OSS made by I&M were due only to the MWh freed up by Electric Choice customers, these Electric Choice customers would still get only their proportional share of total OSS revenue (after deduction of I&M's 20%) despite the fact that they caused 100% of that revenue.</u> 2 TR 178-79.

Thus, under the I&M OSS revenue split, standard service and OAD customers pay exactly the same fixed capacity cost. Standard service customers receive the benefit of low cost I&M regulated energy prices which are typically priced below market rates. Stoddard, 3 TR 357. Mr. Stoddard concluded that if AES customers pay the full cost of generation, they should receive the full benefits. Id., 3 TR 367. AES customers receive none of their energy from I&M and thus receive none of this below market direct benefit. Janssen, 3 TR 410; Heimberger, 2 TR 114. <u>As regards OSS revenue, standard service and OAD customers receive exactly the same share of OSS revenue even if OAD customers free up 100% of the energy which is sold off system.</u> Allen, 2 TR 178-79.

FES Witness Stoddard explained that I&M has very high capacity costs but has extremely low energy costs which are actually well below PJM market rates. By requiring OAD customers to pay I&M capacity costs but not use I&M energy or receive benefits from that low cost energy, I&M virtually ensures that competition cannot exist. Mr. Stoddard also notes that the I&M position on use of OSS revenue also prevents OAD customers from receiving a proper credit for I&M sales of Energy and Ancillary Services off system. Stoddard Direct, 3 TR 357-59.

<u>A Non-Discriminatory OSS Credit Should Be Used For OAD Customers</u>

Mr. Stoddard calculated a proper credit for OSS sales revenue that would give OAD customers 100% of the OSS revenue margin for each MWh of power freed up for sale by OAD customers: $342.20/MW-day. See Exhibit FES-7 (Revised).

Energy Michigan Witness Alex Zakem also testified that the I&M proposal for allocation of OSS revenues was unfair to OAD customers. Mr. Zakem proposed that OAD customers receive OSS credits equal to the total megawatt hours of OAD actual service. In other words, if OAD customers "free up" 280,000 MWh of energy to be sold off system, OAD customers ought to receive the full OSS revenues attributable to the sale of 280,000 MWh of energy. Zakem Direct, 3 TR 236-37. Under this proposal both OAD and standard service customers would receive the full benefit of low cost I&M energy (standard service through regulated energy rates and OAD customers through OSS revenue distribution).

I&M Witness Allen criticized Mr. Stoddard's initial estimate of a proper OSS credit by noting that Mr. Stoddard's calculations did not assign a proper cost of coal and capacity factors to certain I&M units. Allen Rebuttal, 2 TR 164-65. Mr. Stoddard addressed these concerns in his Revised Exhibit FES-7. Mr. Allen also stated that the Stoddard estimate of the E&AS credit uses historical values and does not recognize that approximately 80% of incremental Off System Sales margins are allocated to other members of the AEP pool and that I&M would effectively retain 20% of the margins that were provided to the I&M utility after pool sharing. These arrangements were included in the U-16801 Settlement. Id.

Energy Michigan notes that since the U-16801 Settlement is not precedential in this case, the I&M pooling arrangements are not entitled to be treated as precedent or as requiring a preponderance of evidence to rebut. 2 TR 76-77. It is further noted that Mr. Allen failed to provide substantial justification for the OSS sharing or pooling arrangements other than to merely describe them whereas Energy Michigan and FES provided expert Testimony supporting a 100% credit to OAD customers. Thus the Commission is under no legal obligation to approve an unsupported division of Off System Sales revenues which discriminates against OAD customers.

Michigan Case Precedent Supports the FES and Energy Michigan OSS Credit Proposal

Michigan case precedent supports using the full amount of OSS revenue to, first, offset any claimed stranded costs. Prior Commission decisions give guidance to the Commission that in cases where there is an unrecovered balance between the market price (presumably RPM) of capacity and the regulated rate of capacity (the capacity rate claimed by I&M) it is appropriate to use the full amount of third party OSS revenues to offset that difference. See Case U-13808-R; U-14474 Opinion and Order, September 26, 2006; and U-13917-R Opinion and Order, September 26, 2006.

IV. The I&M/Staff Proposal Violates Michigan Law

A. The Mandate That The Commission Promote Competition And Issue Orders Allowing Competition Is Frustrated By The Exorbitant MPSC Staff/I&M Capacity Charges.

The $384/MW-day capacity rate proposal that AEP filed at the FERC caused the FERC to observe that not only was that filing not shown to be just and reasonable, but that it in fact might be unjust, unreasonable and unduly discriminatory. Commission Order, U-17032, May 24, 2012, page 3-4. In this case, the I&M/Staff capacity proposal has been estimated by FES Witness Lesser to be almost 50% higher than the AEP FERC rate at an average of $588/MW-day. Lesser Direct, 3 TR 302. It is no wonder that implementation of the I&M proposed capacity rates would cause any OAD customers to experience huge losses. Exhibits EM-2 and EM-3. No reasonable or credible evidence has been introduced to dispute the conclusion of Mr. Roy Boston, an expert in the field, that adoption of the I&M/Staff proposed capacity charges would clearly and obviously eliminate all competition on the I&M system. If the Commission knowingly adopts such a result, it would be in violation of the statutory mandates referenced above. See Boston Direct Testimony, 3 TR 260; Banks, 3 TR 278.

B. The I&M/Staff Rates Violate the Mandate of 2008 PA 286 § 11(6) That Rates Be Based on Cost of Service.

As described above, OAD customers purchase absolutely no energy from I&M. Under the mandatory 75/25 allocation mechanism that is a Michigan specific ratemaking principle, 25% of capacity must be allocated on an energy basis, representing benefits of generation that are reflected in the amount of energy used. Yet, I&M/Staff proposed that OAD customers pay exactly the same capacity charges (allocated on a 75/25 basis) despite the fact that standard service customers take all of their energy from I&M and Choice customers take no energy from I&M.

<u>There is no credible or substantial Testimony on this record explaining in detail how the 75%/25% allocation mechanism should be used as regard Electric Choice customers and why the ultimate result of assigning 100% of capacity cost to Choice customers is a fair or rational result.</u>

Therefore, the I&M/Staff proposal violates PA 286 § 11(6) by implementing a rate that is not based on Cost of Service principles used in Michigan. Unless and until a new Cost of Service model is proposed and approved by the Commission for I&M, at a minimum, 25% of capacity costs cannot be allocated to OAD customers. Zakem Direct, 3 TR 232, 239-42.

VI. Energy Michigan Proposals For An I&M State Compensation Mechanism

It should be clearly understood that Energy Michigan would prefer that the Commission adopt the market based RPM pricing mechanism for capacity rates paid by I&M OAD customers as described below. However, recognizing that the Commission may wish to adopt a cost based SCM utilizing Michigan specific Cost of Service ratemaking principles, a Cost of Service based capacity charge approach is offered as an alternative.

A. RPM Market Pricing is the Best State Compensation Mechanism For AES Customer Capacity.

Energy Michigan Support For RPM

Energy Michigan Witness Alex Zakem testified that "I&M should be compensated for the fair value of the capacity service that it provides. In PJM the fair value of capacity for various time periods is established by the Reliability Pricing Model ("RPM"). The RPM is determined by an auction. PJM as a Regional Transmission Organization ("RTO") charges the RPM price to Load Serving Entities ("LES"s) in PJM to pay for capacity purchased at auction to cover the aggregate load of PJM – except PJM does not charge LSEs who have opted, as FRRs, to dedicate specified owned capacity to fulfill their capacity requirements separate from the auction." Zakem Direct, 3 TR 243.

Mr. Zakem, therefore, recommended that I&M be authorized to collect a charge for capacity equal to PJM's RPM "final zonal capacity price" for the zone that includes the Michigan region of I&M. The charge should be applied on a per MW-day basis during the portion of PJM's "delivery year" that the customer takes service from the AES. Id.

Mr. Zakem listed a number of benefits of using the RPM price. The RPM price is appropriate because it represents the value of capacity in the PJM region and changes as the value of capacity changes in a future delivery year. RPM pricing enables competitive supply offered by the AES to reflect the fair market value and provides a market based compensation to I&M for use of its capacity. RPM allows the Commission to set a fair and reasonable transfer price in this proceeding very simply and clearly while maintaining the opportunity for I&M to recover any revenue deficiency or net stranded costs <u>in a separate proceeding</u>. Id., 3 TR 244.

<u>FES Support For RPM</u>

FES Witness Stoddard testified that RPM is the "right price" in terms of economic efficiency because it is the closest approximation to market value of the reliability value of capacity. There were concerns that an RPM rate (approximately $89.50/MW-day on average for the next four years) compared to the $394/MW-day requested by I&M at FERC (Stoddard, 3 TR 354-56) and the $588/MW-day requested by I&M in Michigan (Lesser, 3 TR 302) would not fully compensate I&M for its cost of capacity. Mr. Stoddard responded to those concerns noting that the migration of load to AESs will allow I&M to increase Off System Sales "…allowing I&M to earn as much or more <u>in total</u> from its generation assets" [than from standard service sale of capacity and energy]. Stoddard, Id.

As noted above, I&M may have high, above market capacity costs but it also has low, below market energy costs. As load migrates from standard service to the OAD Choice rate, I&M may experience reduced revenue from capacity sales but its OSS energy revenue should increase to market levels. This conclusion is reinforced by Mr. Stoddard's calculation that the sale of I&M energy should earn, after costs, approximately $342/MW-day from energy and ancillary service sales into the market. Exhibit FES-7. As markets tighten in the future, the revenue earned by I&M should increase proportionately.

<u>A Phase In Option to Mitigate Rate Shock</u>

Another concern raised about RPM pricing is the immediate gap between I&M tariff capacity rates and RPM revenue. Alex Zakem proposed that any estimated gap between appropriate RPM capacity pricing and the current I&M authorized tariff revenue net of savings – i.e., "stranded costs" – could be deferred for collection in a separate proceeding. Zakem, 3 TR 233. 2008 PA 286 § 11(6) seems to contemplate the need for deferral or phase in of rates to soften any shock between current rate levels and implementation of higher cost based rates. This type of approach was used in Ohio as described by Mr. Zakem and could be used in Michigan. Zakem, Id, TR 245[1].

2008 PA 286 § 11(6) is relevant because it notes the possibility that the rates approved by the Commission "<u>in each utility's first general rate case</u>" (emphasis supplied) could be phased in if the increases would have a material impact. In this case, the Commission and I&M are considering OAD capacity rates <u>for the first time in the history of I&M</u>. This first time situation would seem to fit within the requirements of Section 11(6) and would allow use of phase in mechanisms to implement any rate increase approved by the Commission for the first time.

The need for special consideration of "rate shock" in this case is underscored by the fact that there was no way for Choice customers and AESs who serve them to avoid a rate increase produced by this case. AESs in FRR areas are allowed to self-supply their capacity but they must do so in the context of an auction process that has a three year "forward" supply requirement. Therefore in order to contract for self-supply of capacity in 2012, AESs would have had to anticipate this situation three years and contract for needed capacity in the year 2009. Stoddard, 3 TR 342. Such an expectation is unreasonable. Alternatively, any gap between RPM pricing and a higher price selected by the Commission could be deferred to 2016, the earliest date when I&M theoretically could adopt RPM pricing.

B. As An Alternative to RPM Pricing, The Record Supports A Reasonable Capacity Charge Based On Michigan Cost Of Service Principles.

[1] In the case referenced by Mr. Zakem, the Ohio PUC adopted the PJM RPM RTO rate as the capacity charge in its SCM. I&M's affiliate utilities will be allowed to recover the difference between this rate and $188/MW-day (sharply reduced from the requested $77/MW-day rate proposed) through some unspecified deferral mechanism. Stoddard, 3 TR 352.

The capacity charge proposed by I&M/Staff costs an average of $588/MW-day. Lesser, 3 TR 302. The capacity charge filed by AEP on behalf of I&M at the FERC was $394/MW-day – a level prompting FERC to observe that the filing not only was not shown to be just and reasonable but might be "unjust, unreasonable, unduly discriminatory or deferential or otherwise unlawful". April 30, 2012 Order, Docket ER12-1173-000, page 7. Not surprisingly, Energy Michigan Witness Boston found that the rate proposed by I&M in this case would destroy competition by producing losses ranging from 15% to 36% <u>without even accounting for giving AESs a profit</u>. See Exhibits EM-2 and EM-3.

Thus, the I&M proposal is not workable as proposed, but can be modified by cost-of-service evidence submitted in this proceeding, as described below.

The proposed $588/MW-day I&M capacity charge should be reduced as follows:

1. Recalculate OSS revenue credits for OAD service, on the basis of causation.

   OSS revenue at the rate of $342.20/MW-day should be attributed to each MWh of OAD service as a credit against capacity charges. This credit is justified by the fact that each MWh of OAD services frees up 1 MWh of excess energy available for sale and thus <u>causes</u> 1 MWh of additional Off System Sales. Therefore if OAD customers are required to pay the same capacity charges as standard service customers, the OAD customer should get the full benefit of low cost energy resulting from the use of that capacity. This would give the OAD customers the same benefit as standard service customers who get the full benefit of low cost energy produced by the high cost generating facilities funded with capacity charges. Zakem, 3 TR 236-38; Stoddard, 3 TR 367.

   I&M Witness Allen has complained that this outcome does not take into account various I&M/AEP pooling arrangements and cost sharing. Allen Rebuttal, 2 TR 164-65. Yet, none of those pooling arrangements or cost sharing arrangements has been supported by Testimony demonstrating that they are non-discriminatory or even good public regulatory policy. Also, the U-16801 Settlement that adopted those arrangements is not precedent in this case. 2 TR 76-69. Contrast this lack of support against the extreme inequity and discrimination inherent in depriving an OAD customer of benefits from low cost energy which are conferred on the standard service customer paying the full capacity cost. Mr. Allen's mere description of the pooling arrangements in his Rebuttal and cross examination does not rise to the level or evidence necessary to overcome a presumption of discrimination and illegality inherent in an approach that requires two customers (OAD and standard service) <u>to pay the full capacity charge but gives the standard service customer 100% of the benefits of low cost energy and deprives the OAD customer of those benefits.</u>

Energy Michigan's recommendation is that only the *additional* off-system sales – the amount of energy freed up by Electric Choice -- be credited against proposed capacity charges. The "ordinary" amount of OSS would continue to be credited to full-service customers. 100% of freed-up sales revenue <u>caused</u> by Choice should be awarded to OAD customers for each MWh of OAD service because OAD service <u>caused</u> these revenues. Both Witnesses Heimberger and Janssen have testified that cost causation is an appropriate ratemaking technique. Heimberger Testimony, 2 TR 106; Janssen Cross, 3 TR 413. Expert Testimony from both Alex Zakem (3 TR 236-38) and Robert Stoddard (3 TR 367) support granting OAD customers an MWH/MWH credit for all OSS revenues caused by OAD service. Neither I&M nor Staff have credible opposing evidence or Testimony.

2. The allocation of production costs to OAD customers must be reduced by 25%.

Virtually all witnesses to this case who have testified on this subject agree that the Michigan jurisdiction requires an <u>allocation</u> of production costs on a 75/25 basis with 25% of those costs allocated on the basis of energy supplied. Since I&M energy is not consumed by OAD customers, they should not be allocated 25% of production costs. It must be remembered that a Cost of Service model only models allocation of costs not causation of costs. Zakem, 3 TR 232. I&M has not presented Testimony or evidence demonstrating that a different method of allocation than 75/25 can or should be used as regards OAD service. Nor is the I&M Cost of Service study or rates based on that study derived from the Case U-16801 Settlement entitled to a presumption of validity given the ruling of Law Judge Feldman on that issue. 2 TR 76-79.

To the extent that I&M claims any unrecovered costs due to an allocation method that does not allocate 25% of costs to OAD service, I&M has the right to seek recovery of such costs "in a number of forums including general rate cases, the Choice Incentive Mechanism and specific proceedings". Zakem, 3 TR 248.

I&M may claim that it is inconsistent to allocate only 75% of capacity cost to OAD customers while awarding them 100% of the revenue from each MWh of OAD Off System Sales. However, this would be a misinterpretation of how Energy Michigan and FES are recommending that credits from sales of energy be applied.

Removal of 25% of the cost from OAD capacity rates should result in a reduction of approximately $147/MW-day (25% x $588).

Proposed Net Capacity Rate

The reductions of the $588/MW-day I&M capacity rate for an adequate Off System Sales rate of $342 and a $147 reduction in capacity charges for allocation issues reduce the net I&M capacity rate down to approximately $99/MW-day or about $10 above average four year RPM levels which slightly exceed $89.

Rate Increase Phase In

To the extent that the Commission adopts any rate higher than the $99/MW-day proposed above, the difference between that rate and the I&M rate should be phased in over some period of time to avoid rate shock per 2008 PA 286 § 11(6).

VII. Conclusion and Prayer for Relief

WHEREFORE, Energy Michigan respectfully requests that the Commission:

A. Reject the capacity charges applicable to OAD service which are proposed by I&M and the MPSC Staff;

B. Adopt a State Compensation Mechanism charge for capacity applicable to AES customers equal to the prevailing RPM rate as described above or, in the alternative, a rate of $99/MW-day as a cost based rate; and

C. If the capacity charge adopted by the Commission exceeds $99, the charge should be deferred and phased in to avoid rate shock.

Respectfully submitted,

Varnum, LLP
Attorneys for Energy Michigan, Inc.

Eric J. Schneidewind

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August 24, 2012

By: ______________________________

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Fixed Price; Fully Bundled
1 year out 9/1/12

(A) Rate Code	(B) Rate Description	(C) Annual KWh	(D) Utility Annual Cost	(E) Annual Cost (W RPM)	(F) Utility Unit Cost	(G) Price	(H) % Savings	(I)	(J) Price (W/I&M-Proposed Cap Rates)	(K) % Savings
211	Small General Service	10,007	$ 730	$ 460	$ 0.0730	$ 0.0460	37%		$ 0.0836	-15%
215	Medium General Service - Secondary	453,240	$ 32,385	$ 23,772	$ 0.0715	$ 0.0525	27%		$ 0.0947	-33%
217	Medium General Service - Primary	3,462,000	$ 237,997	$ 184,040	$ 0.0687	$ 0.0532	23%		$ 0.0936	-36%
244	Large General Service - Primary	7,245,000	$ 385,374	$ 296,176	$ 0.0532	$ 0.0409	23%		$ 0.0686	-29%
308	Large Power - Subtransmission	18,560,000	$ 1,098,955	$ 837,613	$ 0.0592	$ 0.0451	24%		$ 0.0765	-29%

(A) Rate Code	(B) Rate Description	(C) Estimated Network and Capacity PLC (KW)	(D) Energy	(E) Swing	(F) Distribution Losses	(G) Ancillary Services and ISO Fees	(H) Network Transmission	(I) TEC	(J) Balancing Operating Reserve - Reliability	(K) Balancing Operating Reserve - Deviation	(L) RPM Capacity	(M) I&M Proposed Capacity	(N) Price	(O) Price (W/I&M-Proposed Cap Rates)
211	Small General Service	1.43	$ 0.0345	$ 0.0020	$ 0.0021	$ 0.0014	$ 0.0041	$ 0.0003	$ 0.0003	$ 0.0002	$ 0.0012	$ 0.0389	$ 0.0460	$ 0.0836
215	Medium General Service - Secondary	151	$ 0.0340	$ 0.0020	$ 0.0020	$ 0.0014	$ 0.0091	$ 0.0007	$ 0.0003	$ 0.0002	$ 0.0028	$ 0.0451	$ 0.0525	$ 0.0947
217	Medium General Service - Primary	1,175	$ 0.0354	$ 0.0020	$ 0.0011	$ 0.0014	$ 0.0093	$ 0.0007	$ 0.0003	$ 0.0002	$ 0.0028	$ 0.0432	$ 0.0532	$ 0.0936
244	Large General Service - Primary	1,494	$ 0.0321	$ 0.0020	$ 0.0010	$ 0.0014	$ 0.0028	$ 0.0003	$ 0.0003	$ 0.0002	$ 0.0009	$ 0.0286	$ 0.0409	$ 0.0686
308	Large Power - Subtransmission	4,000	$ 0.0330	$ 0.0020	$ -	$ 0.0014	$ 0.0059	$ 0.0006	$ 0.0003	$ 0.0002	$ 0.0018	$ 0.0332	$ 0.0451	$ 0.0765

Footnotes

1 Price includes energy, shaping, swing premium, losses, capacity, network transmission, renewable portfolio standards, balancing operating reserves, ancillary services and ISO fees.
2 Transmission & capacity obligations, pricing was estimated. Shaping & swing premia, network transmission & capacity obligations were estimated.
3 The capacity rates used for the Price column is RPM ($16.74 for PY 12-13 and $27.86 for PY 13-14).
4 The capacity forecast pool requirement used is 8.69%. The reserve margin used is 6.685% for PY 12/13 and 8.812% for PY 13/14.
5 The utility cost includes the Power Supply Charges (Capacity and Non-Capacity), Power Supply Cost Recovery Fatory and Rate Realignment Charges.
6 The rate used for Network Transmission is for PY 12/13, $27,430.91/MW-Yr.
7 The rate used for Transmission Enhancement Charge is $0.30/MW-h.
8 The capacity rates used for the Price (W/I&M-Proposed Cap Rates) column is proposed tariff rates listed below for each Rate Code.

Rate Code	Capacity Rates
211	Energy Charge (Cents/kWh)-First 2,000 Kwh 4.685; Anything over 2,000 Kwh 1.883
215	Demand Charge ($/kW) 1.18; Energy Charge (Cents/kWh) 4.062
217	Demand Charge ($/kW) 1.15; Energy Charge (Cents/kWh) 3.945
244	Demand Charge ($/kW) 4.81; On Peak Energy Charge (Cents/kWh) 5.581
308	Demand Charge ($/kW) 7.59; 1st 210 On Peak Kwh used per Kw (Cents/kWh) 5.45

EXHIBIT RB-3

	Fixed Price; Fully Bundled
	1 year out 9/1/12

Rate Code	Rate Description	Annual KWh	Utility Annual Cost	Annual Cost (W RPM)	Utility Unit Cost	AES Price	% Savings	Price (W/Staff-Proposed Cap Rates)	% Savings
211	Small General Service	10,007	$ 730	$ 460	$ 0.07296	$ 0.04595	37%	$ 0.08355	-15%
215	Medium General Service - Secondary	453,240	$ 32,385	$ 23,772	$ 0.07145	$ 0.05245	27%	$ 0.09465	-32%
217	Medium General Service - Primary	3,462,000	$ 237,997	$ 184,040	$ 0.06875	$ 0.05316	23%	$ 0.09348	-36%
244	Large General Service - Primary	7,245,000	$ 385,374	$ 296,176	$ 0.05319	$ 0.04088	23%	$ 0.06851	-29%
308	Large Power - Subtransmission	18,560,000	$ 1,098,955	$ 837,613	$ 0.05921	$ 0.04513	24%	$ 0.07643	-29%

Rate Code	Rate Description	Estimated Network and Capacity PLC (KW)	Energy	Swing	Distribution Losses	Ancillary Services and ISO Fees	Network Transmission	TEC	Balancing Operating Reserve - Reliability	Balancing Operating Reserve - Deviation	RPM Capacity	Staff Proposed Capacity	Price	Price (W/Staff-Proposed Cap Rates)
211	Small General Service	1.43	$ 0.0345	$ 0.0020	$ 0.0021	$ 0.0014	$ 0.0041	$ 0.0003	$ 0.0003	$ 0.0002	$ 0.0012	$ 0.0388	$ 0.0460	$ 0.0836
215	Medium General Service - Secondary	151	$ 0.0340	$ 0.0020	$ 0.0020	$ 0.0014	$ 0.0091	$ 0.0007	$ 0.0003	$ 0.0002	$ 0.0028	$ 0.0450	$ 0.0525	$ 0.0947
217	Medium General Service - Primary	1,175	$ 0.0354	$ 0.0020	$ 0.0011	$ 0.0014	$ 0.0093	$ 0.0007	$ 0.0003	$ 0.0002	$ 0.0028	$ 0.0431	$ 0.0532	$ 0.0935
244	Large General Service - Primary	1,494	$ 0.0321	$ 0.0020	$ 0.0010	$ 0.0014	$ 0.0028	$ 0.0003	$ 0.0003	$ 0.0002	$ 0.0009	$ 0.0285	$ 0.0409	$ 0.0685
308	Large Power - Subtransmission	4,000	$ 0.0330	$ 0.0020	$ -	$ 0.0014	$ 0.0059	$ 0.0006	$ 0.0003	$ 0.0002	$ 0.0018	$ 0.0331	$ 0.0451	$ 0.0764

Footnotes

1 AES price includes energy, shaping, swing premium, losses, capacity, network transmission, balancing operating reserves, ancillary services and ISO fees.

2 Network transmission & capacity obligations, pricing is estimated. Shaping & swing premia,
network transmission & capacity obligations are estimated.

3 The capacity rates used for the Price column is RPM ($16.74 for PY 12-13 and $27.86 for PY 13-14).

4 The capacity forecast pool requirement used is 8.69%. The reserve margin used is 6.685% for PY 12/13 and 8.812% for PY 13/14.

5 The utility cost includes the Power Supply Charges (Capacity and Non-Capacity), Power Supply Cost Recovery Factor and Rate Realignment Charges.

6 The rate used for Network Transmission is for PY 12/13, $27,430.91/MW-Yr.

7 The rate used for Transmission Enhancement Charge is $0.30/MW-h.

8 The capacity rates used for the Price (W/Staff-Proposed Cap Rates) column included the .2% rate reduction from AEP MI proposed tariff rates listed below for each Rate Code.

Rate Code	Capacity Rates
211	Energy Charge (Cents/kWh)-First 2,000 Kwh 4.685; Anything over 2,000 Kwh 1.883
215	Demand Charge ($/kW) 1.18; Energy Charge (Cents/kWh) 4.062
217	Demand Charge ($/kW) 1.15; Energy Charge (Cents/kWh) 3.945
244	Demand Charge ($/kW) 4.81; On Peak Energy Charge (Cents/kWh) 5.581
308	Demand Charge ($/kW) 7.59; 1st 210 On Peak Kwh used per Kw (Cents/kWh) 5.45

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

****

In the matter, on the Commission's own motion, to initiate a proceeding to establish a state compensation mechanism for alternative electric supplier capacity in INDIANA MICHIGAN POWER COMPANY'S Michigan service territory.	)	Case No. U-17032

PROOF OF SERVICE

STATE OF MICHIGAN)
) ss.
COUNTY OF INGHAM)

Monica Robinson, the undersigned, being first duly sworn, deposes and says that she is a Legal Secretary at Varnum LLP and that on the 24th day of August, 2012, she served a copy of the Energy Michigan, Inc.'s Initial Brief upon those individuals listed on the attached Service List by email at their last known addresses.

Monica Robinson

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