STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter, on the Commission’s Own Motion, to Commence a Proceeding to implement the provisions of Public Act 169 of 2014, MCL 460.11(3) et seq., with regard to CONSUMERS ENERGY COMPANY.

_____________________________________ Case No. U-17688

NOTICE OF PROPOSAL FOR DECISION

The attached Proposal for Decision is being issued and served on all parties of record in the above matter on May 1, 2015.

Exceptions, if any, must be filed with the Michigan Public Service Commission, 7109 West Saginaw, Lansing, Michigan 48917, and served on all other parties of record on or before May 8, 2015, or within such further period as may be authorized for filing exceptions. If exceptions are filed, replies thereto may be filed on or before May 15, 2015.

The Commission has selected this case for participation in its Paperless Electronic Filings Program. No paper documents will be required to be filed in this case.

At the expiration of the period for filing exceptions, an Order of the Commission will be issued in conformity with the attached Proposal for Decision and will become effective unless exceptions are filed seasonably or unless the Proposal for Decision is reviewed by action of the Commission. To be seasonably filed, exceptions must reach the Commission on or before the date they are due.
May 1, 2015
Lansing, Michigan
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PROPOSAL FOR DECISION

I.

HISTORY OF PROCEEDINGS

In accordance with 2014 PA 169, MCL 460.11(3) et seq. (Act 169), on August 5, 2004, the Commission issued an order in this docket (the August 5 order) commencing this contested case hearing for Consumers Energy Company (Consumers) “to examine cost allocation methods and rate design methods used to set rates.” The August 5 order directed Consumers to make the filing required by Section 11(3) of Act 169, MCL 460.11(3), not later than October 6, 2014. Consistent with the Commission’s directive, and in accordance with the statutory time constraints imposed by Act 169, Consumers filed its application--complete with supporting testimony from 3 witnesses and 14 exhibits--on October 6, 2014.

Pursuant to due notice, a prehearing conference was held in this matter on November 10, 2014, before Administrative Law Judge Mark E. Cummins (ALJ). In the
course of that prehearing conference, petitions to intervene submitted by the following parties were considered and granted without objection: Attorney General Bill Schuette (Attorney General); the Association of Businesses Advocating Tariff Equity (ABATE); Energy Michigan, Inc.; Michigan Environmental Council, the Natural Resources Defense Council, and Citizens Against Rate Excess (collectively, MEC); Hemlock Semiconductor Corporation (Hemlock); the Michigan Cable Telecommunications Association (MCTA); and the Michigan Agri-Business Association (MABA). Consumers and the Commission Staff (Staff) also attended the prehearing and a schedule was established for the proceedings that complied with both the statutory structure and the time requirements imposed by Act 169. ¹

Consistent with that schedule (save for one slight extension agreed to by the parties and the ALJ with regard to the filing of direct testimony by the Staff and the intervenors), evidentiary hearings were conducted on March 4 and 5, 2015. In the course of those hearings, testimony was received from 12 witnesses, three each on behalf of Consumers and the Staff, two on behalf of MEC, and one each on behalf of ABATE, the Attorney General, Hemlock, and Energy Michigan. ² The resultant record consists of 3 volumes of transcript totaling 639 pages and 86 exhibits, each of which was received into evidence. Following the close of the record, Consumers, the Staff, MEC, ABATE, Hemlock, and Energy Michigan filed briefs and reply briefs on March 25 and April 1, 2015, respectively.

¹ Among other things, Act 169 requires the submission of an interim report to the Legislature summarizing the evidence and describing the respective positions of the parties (which was delivered to the Legislature on March 4, 2015), as well as the Commission’s issuance of its final decision in this case within 270 days of the application’s filing.

² No testimony was submitted on behalf of either MCTA or MABA.
II.

REGULATORY AND STATUTORY BACKGROUND

At its heart, this proceeding concerns the issue of how to best allocate certain costs incurred by Consumers that arise from the utility’s provision of electric service to each of its various customer groups or classes. Chief among those are the allocation of the company’s production- and transmission-related expenses.

As noted in its November 2, 2009 order in Case No. U-15645 (the November 2 order), from the mid-1970s through 2005, the Commission—relying on its generally broad ratemaking authority—applied a 12 coincident peak (12CP)\(^3\) 75/25 method to allocate both Consumers’ production and transmission costs. Under that structure, 75% of those costs were allocated to customers based on their contribution to peak demand, while the remaining 25% was assessed based on their contribution to overall energy usage. See, the November 2 order, pp. 69-74. Subsequently, in the course of its December 22, 2005 order in Case No. U-14347, the Commission adopted a multi-hour, four coincident peak (MH4CP)\(^4\) 25/50/25 structure for allocating Consumers’ production and transmission expenses, which “consisted of a 25% weighting of peak demand, a 50% weighting of on-peak energy use, and a 25% weighting of total energy use.” Id., p. 69.

Shortly thereafter, the Legislature enacted 2006 PA 286, MCL 460.11 (Act 286) which [in addition to (1) mandating that electric rates be realigned to remove all inter-

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\(^3\) The 12CP method, which is widely used throughout the electric industry, relies on data taken from the peak hour of electric usage recorded during each month of the year.

\(^4\) The MH4CP method uses data from a seven-hour time frame, running from 1:00 p.m. to 8:00 p.m., on the peak day of each summer month, June through September.
class subsidies by requiring them to be based strictly upon cost-of-service principles on or before October 6, 2013, (2) allowing utilities to rely on projected test year data when submitting rate case filings, and (3) providing the opportunity for self-implementation of a rate increase request 180 days following its submission] provided that:

[T]he cost of providing service to each customer should be based on the allocation of production-related and transmission costs based on using the 50-25-25 method of cost allocation.

MCL 460.11(1). As was then noted by the Commission, the effect of the Legislature’s action in this regard was to “shift the weighting of peak demand halfway back (to 50%) to where it had been prior to 2005, without specifying the coincident peak component.”

November 2 order, p. 72. Consistent with Act 286, the Commission has approved the use of the 50/25/25 allocation structure for production and transmission costs in each of Consumers last four rate cases, albeit with the application of the 12CP structure in Cases Nos. U-15645 and U-16191 for both production and transmission costs, followed by the use of the 4CP structure with regard to production costs (with transmission expense allocation continuing to adhere to the 12CP method) in Cases Nos. U-16794 and U-17087.

Subsequently, Act 169 was enacted, which served to amend Act 286. As a result of this amendment (which was given immediate effect as of June 17, 2014), Subsection 11(1) currently provides as follows:

Except as otherwise provided in this subsection, the commission shall phase in electric rates equal to the cost of providing service to each customer class over a period of 5 years from October 6, 2008. If the commission determines that the rate impact on industrial metal melting customers will exceed the 2.5% limit in subsection (2), the commission may phase in cost-based rates for that class over a longer period. The cost of providing service to each customer class shall be based on the allocation of production-related and transmission costs based on
using the 50-25-25 method of cost allocation. The commission may modify this method to better ensure rates are equal to the cost of service.

MCL 460.11(1) [emphasis added]. Among Act 169’s other provisions, that legislation also added the following requirements in subsections 3 and 4:

(3) Within 60 days of the effective date of the amendatory act that added this subsection, the commission shall commence a proceeding for each affected electric utility to examine cost allocation methods and rate design methods used to set rates. In each proceeding, each affected utility shall file within 60 days of the commencement of that proceeding a proposal to modify the existing cost allocation methods and rate design methods that have been used to set existing rates and shall provide notice to all of that utility’s customers outlining the proposed cost allocation methods and rate design methods. **A proposal filed by an affected electric utility must meet both of the following conditions:**

(a) Be consistent with subsection (1), which authorizes the commission to modify the 50-25-25 method of allocating production-related and transmission costs to better ensure rates are equal to the cost of service.

(b) Explore different methods for allocation of production, transmission, distribution, and customer-related costs and overall rate design, based on cost of service, that support affordable and competitive electric rates for all customer classes.

(4) The scope of a proceeding under subsection (3) is limited to examining cost allocation and rate design methods proposed to set rates for each affected electric utility that filed a proposal under subsection (3). The commission shall allow any interested person to intervene in a proceeding under subsection (3), including on behalf of residential utility customers. The commission shall not schedule a prehearing conference for the purposes of considering interventions until an electric utility files a proposal under subsection (3). Within 270 days after a proposal is filed under subsection (3), **the commission shall issue a final order adopting the cost allocation methods and rate design methods considered appropriate by the commission** and doing either of the following:

(a) Implementing rates consistent with those cost allocation methods and rate design methods.
(b) Fixing a date for the establishment of rates consistent with those cost allocation methods and rate design methods, which date shall not be later than December 1, 2015.

MCL 460.11(3) and (4) [emphasis added].

It is against this regulatory and statutory backdrop that the Commission must review Consumers’ October 6, 2014 application in this case, as well as each of the parties’ various responses and alternative suggestions.

III.

SUMMARY OF THE EVIDENCE AND POSITIONS OF THE PARTIES

A. Consumers

Consumers presented a combination of direct and rebuttal testimony, as well as related exhibits, from each of its three witnesses. These witnesses were Stephen P. Stubleski (the utility’s Director of Cost Analysis, Pricing, and Rate Administration in the company’s Rates and Regulation Department), Michael H. Ross (a Principal Rate Analyst in Consumers’ Rates and Business Support Department), and Laura M. Collins (a Senior Rate Analyst II in the Pricing Section of the utility’s Rates Department).

By way of his testimony, Mr. Stubleski sought to “provide a general overview of the Company's filing,” explain both “what the filing includes” and “the general basis for the Company's proposals,” and “discuss the timing for implementation” of the utility's proposal. 2 Tr 220. In so doing, he noted that--consistent with Act 169--Consumers’ proposal must be “consistent with subsection (1), which authorizes the Commission to modify the 50/25/25 method of allocating production-related and transmission costs” in order to “better ensure rates are equal to the cost of service,” while also exploring
“different methods of allocating production, transmission, distribution, and customer-related costs and overall rate design” (again based on cost of service constructs) that “support affordable and competitive electric rates for all customer classes.” 2 Tr 221.

According to him, the utility’s proposal meets the above-stated requirements because:

The Company’s current Commission-approved rates utilize a 50/25/25 method of allocating production-related and transmission costs as required by MCL 460.11(1). In addition, the Company has met the requirement to phase in rates equal to the cost of providing service within the statutory five-year requirement, with the exception of the Economic Development subsidy which is allowed to continue through the contract term.

Id.

In preparation for its application in this proceeding, Mr. Stubleski continued, Consumers not only evaluated its current electric rates in an attempt to find cost allocation and rate design changes that would serve to better align cost allocation with cost causation, but also considered the recommendations of the Energy-Intensive Industrial Rates Workgroup chaired by members of the Michigan Economic Development Corporation (MEDC Workgroup) as set forth in its final report (Workgroup Report). See, 2 Tr 220-225. With regard to this last component, he stated that:

The [MEDC Workgroup] consisted of business decision-makers representing Consumers Energy and DTE Energy, a representative of the Michigan Electric and Gas Association, a representative from the Michigan Electric Cooperative Association, and ten energy-intensive business customers from a broad range of industries and geographic locations, and staff members from the Michigan House, the Michigan Senate, the [Commission], and was chaired by Steve Bakkal of the MEDC. The recommendations of this Workgroup are set forth in the August 12, 2014 Workgroup Report, provided [in this case] as Exhibit A-14.

2 Tr 222-223. Moreover, Mr. Stubleski continued, the MEDC Workgroup was convened as a result of the fact that:
In December 2013, Governor Rick Snyder outlined his vision for a “no regrets” energy future by 2025 with a number of parameters, including: 1) Adaptability, 2) Reliability, 3) Affordability, and 4) Protection of the Environment. Under the parameter [entitled] Affordability, there were two objectives: a) Residential customers should spend less on their combined energy bills (electric and heat) than national averages, and b) “Ensure energy-intensive industries can choose Michigan for job and investment decisions, to better compete.” As stated in the Workgroup Report, the purpose of the Workgroup was to get energy-intensive industrial customers’ views on how to achieve the Governor’s goal to “ensure energy-intensive industries can choose Michigan for job and investment decisions, to better compete.

2 Tr 223. According to Mr. Stubleski, when preparing its application in this case, the utility specifically considered various recommendations set forth in the Workgroup Report pertaining to both cost allocation (which are discussed in detail by Mr. Ross) and rate design (which are addressed by Ms. Collins). See, 2 Tr 224-225.

Mr. Stubleski went on to describe the overall rate impact that would result from the proposed cost allocation and rate design changes proposed in Consumers’ application. Specifically, he stated that if those changes are implemented: (1) they would “result in a reduction to the rates of the Company’s Industrial customers served at Primary voltages,” (2) “Commercial customers served on Primary voltage will experience rate reductions similar to Primary Industrial Customers,” (3) “Commercial customers served at Secondary voltages will also experience a small rate reduction,” and (4) “Residential customers will see a rate increase of approximately 2.5%.” 2 Tr 225-226. Nevertheless, he continued, although “residential rates are expected to slightly increase, the average residential monthly electric bill is expected to remain below the US average.” 2 Tr 226.

Mr. Stubleski concluded his direct testimony by stating that, if the Commission realigns rates as a result of this proceeding, any new rates should only be effective for
service rendered on and after December 1, 2015 (which is the final date permitted for
the implementation of rate changes resulting from Act 169). See, 2 Tr. 226. In support
of this proposal, he testified that:

The Company believes that it is in the best interest of all customers to
implement rates on December 1, 2015, because the Economic
Development Rate E-1 contract expires on November 30, 2015 and the
associated subsidies for that rate will be eliminated. When the subsidy is
eliminated, it will necessitate a change in all customer rates to reflect that
change. Therefore, the Company believes that current rates should be
maintained until new rates can reflect both the rate realignment in
compliance with Act 169 and the termination of the Rate E-1 subsidies.

Id.

By way of his rebuttal testimony, Mr. Stubleski took issue with statements by one
of MEC’s witnesses to the effect that (1) the proposals mentioned in Consumers’
application do not support the creation of affordable and competitive electric rates for all
customer classes—as allegedly mandated by Act 169—because they merely shift costs
from one class to another without any effort to reduce them, and (2) that a comparison
of the utility’s rates to those of other states indicates that they are neither affordable nor
competitive—as also purportedly required by Act 169. See, 2 Tr 230.

With regard to the first issue, Mr. Stubleski testified that Act 169 “does not require
that the utilities submit proposals to reduce costs,” but rather asks that they simply
explore different methods of cost allocation and rate design “that support affordable and
competitive rates for all customer classes.” Id. Moreover, he asserted that although the
adoption of Consumers’ proposals would increase rates for its residential customers,

5 Testimony offered in both this and other rate cases concerning Consumers has made it clear
that, at least as of late, only one of the utility’s customers is taking service under Rate E-1, namely
Hemlock, and that the utility’s contract with Hemlock for the provision of service under Rate E-1 will—as
Mr. Stubleski noted—does indeed expire on November 30, 2015.
the overall impact on those customers is “very small,” and that the corresponding “5% proposed reduction to the Primary class rates” could be characterized as “helping to make the Company’s rates more competitive.” 2 Tr 231. As for the second issue, Mr. Stubleski contends that the specific rates assessed to customers (which is the standard addressed by MEC’s witness) are not nearly as important as those customers’ average monthly bills (which are a product of both “the amount of energy the customer uses and the cost of that energy”). 2 Tr 232. Because “residential customers in Michigan ranked the 41st lowest in terms of the average electricity used,” he continued, Consumers’ residential customers actually pay 12% below the national average for electricity. See, Id. As such, Mr. Stubleski concluded that because “the Company's proposal to increase residential rates by 2.5% will have little impact on the customer's average annual residential bill compared to other states,” and because the “5% reduction for Primary customers . . . will help lower rates for industrial customers,” Consumers’ proposals will help provide “affordable and competitive rates for all customer classes.” 2 Tr. 233.

Mr. Stubleski also offered rebuttal testimony in opposition to a suggestion from ABATE’s witness that any rate changes resulting from this case be implemented immediately upon issuance of the Commission’s final order, which would need to occur in early July, 2015, at the latest, as opposed to the December 1, 2015 date proposed by Consumers. According to Mr. Stubleski, it would be better to use the later date advocated by the utility because “the residential rate increase would be substantially higher” if rates were implemented prior to the December 1, 2015 cut-off established by Act 169. 2 Tr 223. Moreover, he noted, if the Commission elected to immediately impose any rate changes arising from this proceeding, as ABATE suggests:
[T]he Company would have to implement new rates again on December 1, 2015, when the Rate E-1 subsidy terminates. Additionally, the Company would also need to implement the rates approved in the Company’s general electric rate case filed on December 5, 2014 [Case No. U-17735], assuming that the Commission would approve rate changes with a final order in that case, and implement another rate change to remove the O&M associated with the retirement of the Company’s Classic 7 Coal Units sometime in the April 2016 timeframe. Implementing up to four major rate changes in less than an 8-month period would be confusing for customers, since each rate change would require proration of rates based on effective dates and the rate changes would involve increases and decreases for the various customer classes with each implementation.

2 Tr 234. It is for these reasons, Mr. Stubleski contends, that the Commission should adopt Consumers’ proposed implementation date of December 1, 2015.

Mr. Ross offered testimony on behalf of the utility that focused on the allocation of the company’s production-, transmission-, distribution-, and customer-related expenses. According to this witness, the starting point for the various proposals set forth in Consumers’ application “is the final 2013 test year [cost-of-service study (COSS)] reflecting the rates approved by the Commission in the Company’s last electric general rate case.”6 2 Tr 121. From there, Mr. Ross created a modified COSS, received as Exhibit A-10, which integrates the cost allocation methodologies proposed by Consumers in this case. According to him, that modified COSS (which forms the

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6 On May 15, 2013, the Commission issued its order approving the settlement reached by the parties to that proceeding, namely Case No. U-17087. As noted by Mr. Ross, the utility’s existing COSS, as developed in the course of that case, meets the cost allocation mandates of MCL 460.11(1). Specifically, he testified that:

The statute required utilities to develop production and transmission cost allocators based on the 50/25/25 method of cost allocation with the caveat [that] the Commission could modify this method to better ensure rates are equal to the cost-of-service. The Case No. U-17087 [COSS] uses the 50/25/25 methodology for transmission and production cost allocation. In addition, the Case No. U-17087 [COSS] and rate design meet the mandated requirements for cost-based rates.

2 Tr. 126.

U-17688
Page 11
basis of the utility’s current application) uses a 4CP 100/0/0 weighting methodology to allocate production capacity costs, and a 12 CP 100/0/0 structure for allocating transmission-related costs. See, 2 Tr 127-129.

Mr. Ross testified that, because its peak daily demands “are overwhelmingly set in the summer months,” allocating Consumers’ production costs in accordance with each customers class’s “contribution to our summer system peak demands provides a much more straightforward reconciliation to cost causation principles” than does the existing practice of including customers’ energy usage profiles in the allocation of such demand-based expenses. 2 Tr 127. Thus, he stated, the utility’s proposal to use a 4CP 100/0/0 allocator for production-related expenses “better aligns each customer class’s assigned capacity cost recovery with the capacity costs actually incurred to serve each customer class.” Id. According to Mr. Ross, the result of eliminating all aspects of an energy- or usage-based weighting from this allocation structure (as the utility’s proposal does) would serve to increase the Residential and Secondary classes’ production-related costs by $46 million and $7 million, respectively, while reducing the amount of such costs assigned to Primary customers (i.e., large industrial and a few large commercial users) by $50 million. See, 2 Tr 127. This change would, he continues, “increase a full service Residential customer’s average monthly bill by $2” and “increase a full service Secondary customer’s average monthly bill by $3,” while concurrently serving to “decrease a full service Primary customer’s bill by $1,345.” Id.

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7 Although Mr. Ross’s direct testimony on this topic did not specifically address the $3 million difference between the extra $53 million in costs to be collected from residential and secondary class customers, and the $50 million in reduced production-related expenses to be recovered from Consumers’ primary class customers, this difference may well be related to the roughly $3 million overall cost reduction expected to be provided to the utility’s Street Lighting and Other customer classes.
Regarding how to best allocate Consumers’ transmission costs, Mr. Ross stated that the company “incurs transmission expense on a predominately demand basis consistent with 12 coincident peaks,” thus leading to its proposal to implement a 12CP 100/0/0 allocation methodology for these costs. 2 Tr 129. According to him, changing the allocation structure from the current method (which used the 50/25/25 allocation set forth in Act 286) to one focusing 100% on demand levels would increase the costs assigned to residential customers by $12 million annually and reduce those assigned to primary customers by $11 million per year, while leaving the expenses assigned to the utility’s secondary customers essentially unchanged. See, Id. This action would, he continued, increase a full service residential customer’s average monthly bill by $1 and reduce a full service secondary customer’s average monthly bill by 15 cents, while also serving to “decrease a full service Primary customer’s average monthly bill by $307.” 2 Tr 129.

Turning to the issue of how Consumers’ distribution-related expenses should be allocated among its various customer classes, Mr. Ross testified that, “to better align with cost-of-service principles,” a change should be made to how costs related to the utility’s highest voltage distribution plant assets are allocated. 2 Tr 130. Specifically, he stated that:

The Company proposes to use class peak demands at generation, inclusive of Retail Open Access [ROA] demands, as the allocator for the amounts related to high voltage distribution assets. This methodology is consistent with the design and implementation of these assets to meet customer maximum area load requirements, as well as the National Association of Regulatory Utility Commissioners [NARUC] guidelines. Id. According to Mr. Ross, making this change would increase the cost of serving primary customers by $2 million, while reducing the costs assigned to residential and
secondary customers by the same amount. This would, he continued, reduce the average monthly bills for residential and secondary customers by 3 cents and 45 cents, respectively, while increasing a full service primary customer’s average monthly bill by $48.

With regard to the allocation of customer-related expenses, Mr. Ross noted that, upon its review, Consumers found those used in the 2013 COSS to be generally reasonable. See, 2 Tr 131. Nevertheless, he continued, the utility did find one area that needed revision. Specifically, Mr. Ross asserted that “one of the inputs into the Case No. U-17087 final cost-of-service model,” namely the portion of the test year Other Operation and Maintenance (O&M) expense “attributed to Federal Energy Regulatory Commission (FERC) Account 908, Customer Assistance Expense,” should be altered. According to him:

Currently, test year O&M expenses related to employee benefits and corporate-related costs are allocated to Customer and Sales FERC expense accounts as well as Administrative and General production, customer, and distribution lines prior to input into the cost-of-service model based on the relationship of actual historic test year expense for each line item to the sum total. Applying this methodology and adjusting the historical test year FERC account 908 balance to remove Low Income and Energy Efficiency Fund [LIEEF] and Energy Optimization [EO] related expense results in a significantly lower amount of test year Other O&M [costs] allocated to FERC account 908, and subsequently more test year Other O&M allocated to other cost-of-service line item inputs.

2 Tr 131-132. This change was necessary, Mr. Ross continued, because (1) LIEEF-related costs were not actually included in Other O&M expenses allocated to FERC account 908 in the utility’s most recent rate case, Case No. U-17087, and (2) EO expenses are recovered through imposition of a separately-authorized EO surcharge,
and are thus excluded from Consumers’ general electric rate base applications.  
See, 2 Tr 132.

According to Mr. Ross, making this recommended change to the allocation structure (i.e., reducing the portion of the test year Other O&M expenses allocated to FERC account 908 to remove all LIEEF- and EO-related costs, and making the corresponding increases to other line items within the Case No. U-17087 COSS) would increase the expenses assigned to residential customers by $18 million annually and reduce those assigned to primary customers by $18 million per year, while leaving the expenses assigned to the utility’s secondary customers essentially unchanged.  See, Id.  This would, he continued, serve to increase a full service residential customer’s average monthly bill by $1 and reduce a full service secondary customer’s average monthly bill by 16 cents, while also serving to “decrease a full service Primary customer’s average monthly bill by $482.”  2 Tr 132.

Mr. Ross concluded his direct testimony by noting that, taken as a whole, the company’s proposed cost allocation changes described above would increase the total expenses to be recovered from Consumers’ residential and secondary customer classes each year by $76 million and $6 million, respectively, while reducing the annual costs assigned to its primary class by $78 million and its Street Lighting and Other rate class by $3.2 million per year.  See, 2 Tr 133.  This would, he also noted, raise the average monthly bill of the utility’s full service residential customers by $4, increase the average bill issued to each of its full service secondary customers by $2 per month, and--in return--reduce the average bill assessed to each of its full service primary customers by $2,117.  See, 2 Tr 134.  However, he also pointed out that implementing
these cost allocation changes at the same time that Rate E-1 expires--specifically, on or about December 1, 2015--would allow the termination of the Rate E-1 subsidy to “offset some of the rate impacts discussed above.” 2 Tr 134.

By way of rebuttal, Mr. Ross expressed disagreement with one of the Staff witnesses’ assertions (in favor of adopting a 4CP 75/0/25 allocation methodology) that production assets provide both capacity and energy. According to him, production assets simply “provide capacity,” and should thus only be allocated on a per megawatt (MW) basis, whereas the production of energy “is simply the portion of production capacity demanded from [the utility’s] customers to meet their consumption needs as a function of time,” and thus are both computed and allocated on a per megawatt-hour basis. 2 Tr 137. In addition, he asserted that the Staff’s witness was incorrect in claiming that past orders issued by the Commission regarding production cost allocation have “recognized the dual nature of production assets as providing both energy and capacity” when assigning those costs to various classes of ratepayers. 2 Tr 138. Similarly, Mr. Ross contended that the Staff’s witness was wrong to contend that--under Consumers’ proposed 4CP 100/0/0 production cost allocation structure--a customer class that increases energy usage without increasing peak demand (for example, primary industrial customers that increase energy usage during a non-peak period by adding “Midnight shifts,” etc.) would get “cost-free” service, at least with regard to production costs. Id. Moreover, he disagreed with that witness’s assertions that (1) moving to a 4CP 100/0/0 production cost allocation structure does not satisfy Act 169’s requirement that rates ultimately pass a “reasonability analysis,” and (2) any change to the allocation of the utility’s customer assistance expense should be made
contemporaneously with the Staff’s proposed revision to the allocation of its uncollectible accounts expenses (UAEs), likely in the context of Consumers’ next general gas rate case, and should also be allocated on a per kilowatt-hour (kWh) basis. 2 Tr 140.

Mr. Ross next took issue with statements made by both of MEC’s witnesses. With regard to the first of those witnesses, Mr. Ross testified that—withstanding assertions to the contrary—(1) retaining the current 4CP 50/25/25 production expense allocation methodology is not in keeping with true cost of service principles, (2) that existing methodology was not simply discarded by the utility in drafting its proposal as a way to satisfy the members of the MEDC Workgroup, and (3) shifting to the utility’s proposed 4CP 100/0/0 method for allocating those costs would not, as claimed by MEC’s witness, unfairly burden residential customers with the company’s higher priced steam generation costs. See, 2 Tr 143-149. As for statements provided by MEC’s second witness, Mr. Ross countered that: (1) assertions that “dynamic pricing”8 should be adopted as a result of Consumers’ filing in this case ignore the fact that the utility’s full deployment of smart meters throughout its system would need to be accomplished first, (2) an inadequate basis exists for blindly adhering to suggestions set forth in a manual authored by NARUC9 to the effect that energy-weighted methods of cost allocation do a better job of assessing cost causation than do peak demand-based methods, (3) calls for combining residential and secondary customer classes based

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8 Dynamic pricing, which is often called “time-of-use pricing,” refers to rate structures under which customers are charged more per kWh for electricity consumed during peak hours than they would have to pay for electricity taken during non-peak periods.

9 This publication, generally referred to as the “NARUC Manual,” addresses—among other things—the various ways in which utility costs can be allocated and rates can be designed.
simply on their receipt of service on a common interconnection voltage level “ignores all other cost to serve differences between the two classes,” (4) allowing customers with “behind-the-meter” generation capabilities to “avoid all charges for power they produce and immediately consume,” as well as crediting them for any power that they actually put into the system, would unfairly make them immune from paying for “the actual investment costs that the Company incurs to provide them service,” and (5) that setting standby service charges “based on the cost of new entry of a combustion turbine” could ultimately preclude Consumers from recovering the “prudent, actual costs incurred to provide service,” in conflict with Commission precedent. 2 Tr 149-150 [emphasis in original].

Mr. Ross also rebutted statements made by the Attorney General’s witness in support of his belief that the Commission should reject the utility’s request to shift from the current 50/25/25 production cost allocation structure to the company’s proposed 4CP 100/0/0 method, as well as its request to revise the allocation of Other O&M expenses. According to Mr. Ross, that witness was incorrect in asserting that Consumers’ filing was incomplete because no demand or load forecast was submitted with it. See, 2 Tr 150. Specifically, Mr. Ross noted that the reason that no such forecast was prepared and offered was that both Act 169 and the August 5 order spoke only of the need to make “a review of existing rates, cost allocations, and rate designs.” Id. [emphasis added]. Moreover, he contends that the Attorney General’s witness “gave no discernable reason supporting his recommendation” to leave the allocation of Other O&M costs unchanged, and instead simply “presents some observations regarding Power Supply Cost Recovery (PSCR) expenses,” as well as a “baseless discussion
concerning the Company’s purported lack of discussion regarding other non-base rate surcharges.” 2 Tr 151.

Finally, Mr. Ross took issue with two assertions made by Energy Michigan’s witness, one to the effect that Consumers’ structure for allocating UAEs “is not equitable, and should be changed to a total cost of service method,” and the other to the effect that those UAEs “should be broken into distribution and power supply components.” 2 Tr 151-152. With regard to that witness’s first assertion, Mr. Ross stated that the utility specifically “reviewed the UAE allocator relative to the actual gross write-offs and found the current allocator to reasonably reflect” how those costs are actually incurred. 2 Tr 151. As for the second assertion, he noted that (1) because the amounts in question located in FERC Account 904 simply reflect accounting values, “the act of functionalizing the expenses into distribution and power supply components—as Energy Michigan’s witness recommends—does not adhere to cost causation principles,” and (2) the NARUC Manual points out that customer-related costs such as UAEs “are usually assigned to the distribution function.” 2 Tr 152.

Ms. Collins’ direct testimony was offered to support Consumers’ proposed modifications to the rate design methods used to set the utility’s existing electric rates. See, 2 Tr 38. In this regard, she testified that the utility began with the rate design set forth in the settlement agreement approved by the Commission in Case No. U-17087 (which was based on a 2013 test year), incorporated the results of the updated COSS developed by Mr. Ross, revised the General Primary Demand (GPD) rate—which is applied to its largest customers—so as to “collect all fixed costs through a demand charge” as recommended in the Workgroup Report, increased the resultant “GPD On-
Peak Demand charges . . . in order to collect more of the fixed capacity costs through a non-variable charge,” and “rolled into the GPD rate [all] sales and costs” from Rate E-1 (whose massive subsidy was to be eliminated as of November 30, 2015). See, 2 Tr 39-42. According to her, this resulted in the “calculation of the revenue targets used for designing rates including proposed adjustments to the test-year revenue requirement” as set forth--by rate schedule--on Exhibit A-4. 2 Tr 43.

After describing the way that those test year rate design revenue requirements were developed, Ms. Collins went on to offer Consumers’ position regarding discounts or subsidies that it plans to retain as part of its rate design. In this regard, she noted that although the discounts for the Senior Citizen and Income Assistance Provision rate classes would be allocated in the same manner as in Case No. U-17087, the allocation of capacity costs arising from the Metal Melting Primary Pilot (MMPP) Rate--which generally assumes reduced loads occurring during the high-peak summer months--should be increased just slightly to now allocate approximately $7.7 million of capacity costs. See, 2 Tr 44-45. As for GPD customers taking service under the General Interruptible (GI) Provision, she began by noting that the utility “does not break out Interruptible customers into separate cost columns in the COSS,” and thus the COSS simply allocated capacity costs to the company’s GI customers “in the same manner as all other customers.” 2 Tr 45. However, Ms. Collins went on to note that because

10 Surprisingly, the Rate E-1 discount, which only applied to one large industrial customer located within Consumers’ electric service territory, appears to have created an annualized rate subsidy of $48,504,000. See, 2 Tr. 41. Moreover, unlike most other rate discounts, the subsidy arising from that discount was, “under Michigan law,” allowed to be collected from all other customers through their power supply and delivery charges until the contract relating to the discount expires at the end of November 2015. Id.
Consumers neither plans for nor purchases capacity to serve its GI customers, “an appropriate amount of capacity costs allocated” to them “needs to be removed and spread to other customers for whom capacity is planned and purchased.”

Ms. Collins further testified that Consumers is proposing to “maintain the basic rate design previously approved by the Commission” for its various residential and secondary rate schedules. However, she continued, the rates relating to those particular schedules have changed somewhat as a result of the cost-of-service changes noted earlier, as well as the upcoming elimination of Rate E-1 (and, thus, its significant subsidy). Still, turning to the rate design proposed for its GPD customer class, Ms. Collins stated that, “as discussed in the Workgroup Report, . . . proper rate design collects fixed costs through demand charges.” As a result, she continued, the utility is proposing to increase its on-peak demand charge and collect less by way of its energy charge, therefore allowing higher load factor customers (such as the large industrial customers invited to participate in the MEDC Workgroup) to “see a lower average rate.” As for the delivery charge assessed to GPD customers, Ms. Collins stated that Consumers is proposing to continue the System Access Charge of $100 per month, while collecting all of its remaining demand costs through the Maximum Demand charge (a design change that would be carried through to MMPP and General Primary Time of Use [GPTU] rate schedules as well).

The final set of rate design changes described by Ms. Collins began with the utility’s proposal to establish what it referred to as the general Educational Institution

11 According to Ms. Collins, the GI customers’ capacity credits are allocated to other customers in the same manner that the test-year COSS allocates the utility’s total capacity costs, thus simulating “how capacity would be allocated to customers if the COSS separated out Interruptible customers into their own cost columns.” 2 Tr 46.
Service Provision (GEI), which would be a credit applied to qualifying customers’ bills in order to comply with Act 169’s requirement ensuring that “public and private schools, universities, and community colleges are charged retail rates” reflecting the “actual cost of providing service to those customers.” 2 Tr 48. “For General Service Secondary Rate (GS) and General Service Secondary Demand Rate (GSD),” she continued, the company seeks to “provide a delivery credit that would remove the subsidies for Income Assistance and Senior Citizen” rate class members, and for General Primary (GP) and GPD customers, Consumers proposes to “provide Power Supply and Delivery credits to set their billing at the cost-to-service level based on the Test-Year COSS” performed and sponsored by Mr. Ross. Id. In summarizing her direct testimony, Ms. Collins pointed out that Exhibit A-6 reflects the impact of the utility’s proposals upon “customers on each rate schedule at various usage levels,” Exhibit A-7 summarizes and explains the proposed changes that would be made to the company’s Electric Rate Book, and Exhibit A-8 sets forth the proposed changes to Consumers’ electric tariffs (including the multiplier that she asserted must be applied to “the current Power Factor Credit/Penalty” in order to keep it “at the same revenue level it is at today”). 2 Tr 48-49.

In addition to her above-described direct testimony, Ms. Collins offered rebuttal testimony disputing assertions made by various parties’ witnesses. She started out by testifying that Hemlock’s witness was clearly incorrect in asserting both that (1) the utility’s rate design proposal for GPD Customer Voltage Level 1 “has an unreasonably low demand charge, and a high energy charge relative to Consumers’ cost of service for this class,” and (2) “Consumers is understating its demand charge and overstating its
energy charge,” and thus “creating intra-class subsidization between GPD customers.”

2 Tr 53-54. With regard to the first of these issues, Ms. Collins noted that:

As I stated in my direct testimony, in current rates the Company collects 50% of capacity costs in the on-peak demand charges. In this case, the Company is proposing to collect 75% of capacity costs in the on-peak demand charges. This represents a considerable change in the on-peak demand rates. For example, the GPD voltage level 1 summer on-peak demand charge is proposed to go from $11 to $16. Collecting 100% of the capacity in the on-peak demand charge would increase this to over $21/MW. When rates are designed, the Company has to consider the impacts on all customers in the class. While [Hemlock’s witness's] proposed increase in the On-Peak Demand charge is beneficial to high load factor customers on this rate, it would substantially hurt customers with lower load factors [as reflected on Exhibit A-15].

2 Tr 53. As for that witness’s second assertion, to the effect that Consumers’ proposal creates intra-class subsidization among GPD customers because the suggested demand charge is too low vis-à-vis the utility’s suggested energy charge, Ms. Collins pointed out that:

High load factor customers within the GPD rate class are paying a lower average rate than all other customers. For example, Exhibit A-3 (LMC-3), line 17 shows the present and proposed revenue for the Large Economic Development Rate E-1. The present revenue is based on the contract E-1 rate that is expiring.\(^\text{12}\) The proposed revenue is based on the proposed GPD rate design. The proposed revenue for this class is $137 million (column (c)). However, Exhibit A-4 (LMC-4), column (i) shows Rate E-1 in its own rate class with a cost of service of $154 million. The determinants for Rate E-1 indicate a 90% load factor. Therefore, this high load factor customer is actually paying less under the proposed rate design than if their cost to serve had been determined separately.

2 Tr 54.

She went on to rebut this witness’s further recommendation that, to eliminate what he views as the potential subsidization of distribution charges, Consumers should

\(^{12}\) As alluded to in footnote 10 of this PFD, the only customer that appears to be receiving service under the significantly discounted Rate E-1 is Hemlock, whose contract guaranteeing application of that rate is set to expire at the end of November 2015.
either raise its current Substation Ownership Credit to a level commensurate with the utility’s proposed increase in the maximum demand charge for Rate GPD customers or, alternatively, “adjust distribution bill units for customers that [like Hemlock] own substations.” 2 Tr 55. With regard to this issue, Ms. Collins testified as follows:

In this case, the Company is proposing to collect all of the distribution costs through the Maximum Demand costs, but for the $100 [per month] customer charge. The Company is not proposing any change to the substation ownership credit so as to maintain the same relationship of credit to total delivery costs. If the Company continued to set the credit as an offset to the Maximum Demand charge, customers with substation ownership would essentially pay no distribution costs at all.

* * *

Owning a substation should reduce a customer’s distribution charges, but does not entitle a customer to free distribution service. The Company maintains an entire distribution network to serve customers, and all customers served by that network should be responsible for their share of the costs.

Id. As for this witness’s alternative proposal (to adjust distribution bill units), she noted that this recommendation is based on the mistaken belief that some customers pay for distribution service through facilities agreements. However, Ms. Collins pointed out that:

[C]ustomers do not pay for standard distribution service through facilities agreements. Customers are only required to pay for O&M associated with distribution costs for facilities that are not part of standard service or for those facilities. In these cases, facilities agreements specify the customer costs necessary to maintain the distribution facilities associated with premium services, which includes redundant service and other service not covered under standard service. Redundant facilities are not part of standard service, and customers are required to pay for the incremental facilities and for the O&M to maintain them since they do not provide any benefits to other customers.

2 Tr 55-56.
The next dispute between Ms. Collins and Hemlock’s witness concerned his claim that Consumers should include a high load factor customer class within its GPD cost of service and rate designs in its next general rate case. According to her, the utility specifically looked at this issue as part of the MEDC Workgroup, and page 14 of the Workgroup Report (admitted in this case as Exhibit A-14) explicitly shows that:

[Lower rates were achieved through changing demand charges in the existing GDP rate schedule than through creating a separate high load factor rate class. It is not necessary to put high load factor customers into a separate cost of service column in order to achieve rate savings since rate design can be used to achieve these results.

2 Tr 56.

Ms. Collins also offered rebuttal testimony regarding recommendations made by one of MEC’s witnesses, several of which relate to the issue of dynamic pricing. The first of these disputed recommendations was that dynamic peak pricing be employed whenever Consumers’ total system electric load exceeds a Commission-established threshold. In disagreeing with this particular recommendation, she noted that:

13 On a related topic, Ms. Collins responded to a suggestion by one of the Staff’s witnesses to the effect that, in its next general rate case, Consumers should “present a plan on how it intends to send better price signals to customers” once its ongoing Advanced Meter Infrastructure (AMI) roll-out has been completed. 2 Tr 51. In so doing, she provided rebuttal testimony stating that, although she does not agree with this recommendation, it should be noted that:

[Consumers] has already taken steps to implement dynamic pricing and direct load control rates. The Company currently has the Residential Dynamic Pricing Rate (RDP), Secondary Dynamic Pricing Rate (GSDP), Secondary Demand Dynamic Pricing Rate (GSDDP), and Primary Dynamic Pricing Rate (GPDP). These rates are designed to send price signals to customers to encourage use during the off-peak (lower-priced) time periods. The Company plans to market these rates as the full AMI deployment is achieved. The Company also plans to directly cycle customers’ electric central air conditioners, heat pumps, and other qualifying equipment for the Residential (RS) and General Secondary (GS) rate classes via the Company’s Smart Energy System, and plans are in place to solicit participation later this year.

2 Tr 51-52.
As discussed above, the Company currently has several demand response rates in place and is planning on these programs to deliver future capacity reductions. However, the Company does not have the infrastructure or systems in place to implement dynamic peak pricing for all customers at this time. In the Company’s electric general rate case filing in Case No. U-17735, Lincoln D. Warriner discusses the status of the smart meter installations. He states that smart meter installations are 21% complete as of the end of 2014. In addition, dynamic pricing would be a radical change for many customers. [MEC’s witness] provides no evidence to suggest that his dynamic pricing proposals will result in competitive and affordable rates. The Company would need more time and information to determine what the customer impacts would be before making such a change.

2 Tr 56-57. The second--and closely related--recommendation from MEC’s witness was to begin using interval metering both to allocate costs and to bill customers, thus recognizing individual customer contributions to the cost of providing electric service. Ms. Collins responded to this suggestion by noting that although the utility is in the process of developing systems “to enable interval billing from smart meter data late in 2015,” the company would need to “fully test and validate the accuracy of customer billing from interval data before it will roll out that capability to a large number” of its ratepayers. 2 Tr 58. On a third related topic, she noted that MEC’s witness also proposed that overall rate design be premised on time-specific rates, so that customers could receive signals regarding when the cost of electric service is high and adjust their usage to reduce their own cost of service. In response to this proposal, Ms. Collins stated that:

The Company believes that time-specific rates are one option for signaling to customers when the cost of service is high. In fact, the Company’s dynamic pricing rates I mentioned previously in this rebuttal testimony use time of use rates as the underlying rate design for Power Supply charges. In addition, the Company currently has a residential time of day rate (Rate RT), a metal melting pilot rate (Rate MMPP), and a general primary time of use rate (Rate GPTU) that are also based on time blocks. However, there are other ways to send these signals. The Company has summer block rates for residential customers in which usage over a defined threshold is
priced at a higher rate. In addition, the Company has energy efficiency programs that target end uses during high cost time periods.

2 Tr 58-59.

A fourth area addressed by MEC’s witness with which she took exception concerned proposals regarding behind-the-meter generation and storage. According to Ms. Collins, she disagrees with implementing those proposals for the same reason that she does not support his other rate design proposals. Specifically, she testified that:

The Company does not have the Smart Energy technology or systems in place to determine interval metering and billing for all customers which would be necessary under his proposal. Secondly, I would not support any proposals that result in subsidies for customers who operate generators behind-the-meter, and it is unclear if [MEC’s witness’s] proposals result in subsidies. Customers who rely on the utility’s system for back-up power should be responsible for the distribution facilities that are in place to serve the customer and for the capacity that the utility must have in place to serve the needs of the customer when the customer’s generator does not operate. In addition, there is a requirement that rates reflect costs-to-serve in Michigan, with the exception of the customers who qualify for either Net Metering or for Low Income programs, as allowed for under Michigan law.

2 Tr 59.

Fifth, Ms. Collins objected to that witness’s recommendation to establish a Low Income Household Rate, and insisted that such a rate was unnecessary in light of the fact that Consumers has several low income programs either already in place or in the process of development. See, 2 Tr 57. In this regard, she pointed out that: (1) the utility currently provides “a $7 per month credit for eligible low income customers under the income assistance program;” (2) the Commission recently approved an extension of the company’s Affordable Resource for Energy pilot program, which is designed to help customers establish “new habits of on-time monthly payments and energy usage awareness in order to break the cycle of need,” and thus “transition the customer to self-
sufficient, energy account management;” and (3) Consumers recently concluded its Clear Control pilot program--a collaborative effort aimed at evaluating how providing customers with added information regarding energy use and establishing a different paradigm for customer billing may help low income customers reduce energy consumption while concurrently improving payment performance--for which “a follow-up study is being planned.” \textit{Id.}

Sixth and finally, Ms. Collins took issue with a suggestion by this MEC witness that all energy supply revenue be recovered “as a constant multiplier of the Company’s day-ahead hourly LMP price in the Midcontinent Independent System Operator [MISO] energy market.” \textit{2 Tr 58.} According to her:

While there may be customers that prefer market-based rates, there are probably a greater number that prefer rate certainty and price stability. Many industrial customers develop budgets and production schedules in the future and often request rate forecasts. A rate design based on prices changing hourly would create a lot of uncertainty for customers and would make planning difficult for them.

\textit{Id.} As a result, she opposes implementing that suggestion.

Turning to statements offered by the Attorney General’s witness, Ms. Collins’ rebuttal testimony expressed disagreement with his assertions that (1) Consumers’ application fails to provide any “supporting information as to the impact on customers; it, rather, just presents a calculation of the change in rates,” and (2) that the utility’s proposed residential rate design “does not send the proper price signals to customers.” \textit{2 Tr 52.} With regard to that witness’s first statement, she stated that:

The Company’s filing included Exhibit A-6 (LMC-6), Test-Year Calculation of Typical Bills. This 47-page exhibit presents the typical summer bill, typical winter bill, average rate, and percent change for each rate schedule at various levels of sales.
As for his second statement, Ms. Collins testified that:

The Company’s current residential rate design sets a higher price for usage over 600 kWh/month in the summer, and we are maintaining that rate design in this case. [The Attorney General’s witness] has not proposed an alternative residential rate design.

Based on its witnesses’ above-described testimony, and consistent with both its October 6, 2014 application and its February 19, 2015 Statement of Position (filed as a precursor to the ALJ’s mandatory Interim Report, which was submitted to the Legislature on March 4, 2015), Consumers contends that the Commission should allow the utility to replace its current 4CP 50/25/25 production cost allocation structure with the 4CP 100/0/0 method described by Mr. Ross. See, Consumers’ initial brief, pp. 9-14. In so doing, the company continues, the Commission should expressly reject the proposals offered by the Attorney General (to retain the 4CP 50/25/25 method), the Staff (to change to a 4CP 75/0/25 structure), and MEC (to effectively replace the direct allocation of production costs with the across-the-board implementation of dynamic pricing). See, Consumers’ reply brief, pp. 6-10. Likewise, the company asserts that the Commission should replace the existing 12CP 50/25/25 transmission cost allocation structure with a 12CP 100/0/0 methodology. See, Consumers’ initial brief, pp. 14-15. As for its distribution-related expenses, the utility simply seeks Commission approval of Mr. Ross’s proposal to use class peak demands at generation (inclusive of its ROA

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14 Subsection 6 of Act 169, MCL 460.11(6), requires the Commission to order that the ALJ presiding over a proceeding such as this “prepare an interim report that the commission shall submit to the legislature within 150 days after proposals are filed” by utilities pursuant to Act 169.
customers’ demands) as “the allocator for the amounts related to high voltage distribution assets.”

Turning to its customer-related costs, Consumers contends that their current allocation structure is generally reasonable and should be retained, with one exception. Specifically, the utility contends that Other O&M expenses attributable to FERC Account 908, Customer Assistance Expense, should be revised to remove all LIEEF- and EO-related costs, and that those costs should be assigned to other cost-of-service line item inputs to the COSS. Consumers’ initial brief, p. 16. In this regard, it asks that the Commission should specifically reject the Staff’s proposal to couple any such change with a contemporaneous revision to the allocation of UAEs and have those concurrent changes undertaken in the context of Consumers’ next general rate case or, in the alternative, to simply allocate UAEs on the basis of billed sales. Id., p. 17. The utility likewise requests that the Commission reject Energy Michigan’s suggestions to the effect that UAEs be allocated based on a total cost-of-service basis, and that those costs be broken down into distribution and power supply components. Id., pp. 25-27.

With regard to rate design and tariff-related issues, Consumers seeks approval of numerous changes, each of which were specifically addressed by its witness on this topic, Ms. Collins. The utility’s requests in this regard seek the Commission’s authorization to: (1) revise its rate structure to reflect the effect of Rate E-1’s imminent termination; (2) continue the Senior Citizen and Income Assistance Provision discounts currently incorporated in its rates; (3) continue allocating capacity costs to its MMPP

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15 Doing so would, it appears, essentially serve to reject the voltage level-based distribution cost allocation proposal offered by one of MEC’s witnesses, and which was opposed by both Consumers and the Staff. See Consumers’ initial brief, p. 30 and Staff’s initial brief, p. 20.
customers at approximately the same level approved in prior rate cases; (4) revise the allocation of capacity costs allocated to GPD customers taking service under the GI Provision by increasing their summer interruptible credit from $6.00/kW to $7.00/kW; (5) alter the GPD rate design as a whole to collect approximately 75% of its capacity costs through on-peak demand charges, as opposed to the roughly 50% currently collected in this manner; (6) revise the delivery charge assigned to GPD rates in such a way as to continue the $100 per month System Access Charge, but also beginning to collect all of the remaining delivery costs through the Maximum Demand Charge, a change that would also apply to members of the MMPP, GPTU, and Large Self-Generating (GSG-2) rate classes;\(^{16}\) (7) provide a delivery credit [referred to as the GEI Provision] that would remove the subsidies for Income Assistance and Senior Citizens’ rates from the GS and GSD rate classes’ assignment of costs, thus satisfying Act 169’s requirement that public and private schools, universities, and community colleges are charged rates reflecting the actual cost of their service; (8) initiate Power Supply and Delivery credits to set their bills at the cost-of-service level based on the test year COSS; and (9) make a change to the Adjustment to Power Factor provision of the GPD rate’s tariff to ensure that both the credit and penalty imposed by that provision do not provide inaccurate increases. See, Consumers’ initial brief, pp. 18-24.

In granting the utility authority to make the above-listed rate design and tariff-based changes, Consumers continues, the Commission should also expressly reject all requests by Hemlock to increase the demand charge for GPD Voltage Level 1 customers (while reducing the corresponding energy charge for that rate class), either

\(^{16}\) Although Ms. Collins neglected to specifically mention GSG-2 customers as being part of this group, none of the parties have expressed concern regarding Consumers’ proposal to compute their delivery costs in the same manner.
raise the Substation Ownership Credit or adjust distribution bill units for customers who own substations, and create—in the course of its next general rate case—a high load factor customer group within the GPD rate class.  Id., pp. 21-25; See also, Consumers’ reply brief, pp. 21-22.  In addition, Consumers contends that rates including the utility’s requested changes should be deemed to take effect December 1, 2015 and, that the Commission should specifically find that imposition will support the creation of affordable and competitive rates for all customer classes, as intended by Act 169.

Finally, Consumers argues that the Commission should reject the proposals offered by various parties to, among other things, (1) base stand-by charges on the cost of new combustion turbines, (2) exempt customers with “behind-the-meter” generation abilities from the allocation of various costs, (3) combine residential and secondary customer classes based on common voltage levels, and (4) undertake a full-blown changeover to dynamic pricing or similar price structures.

B.  ABATE

ABATE presented both direct and rebuttal testimony from one witness, namely James T. Selecky, a registered professional engineer and a consultant with the firm Brubaker & Associates, Inc.

In his direct testimony, Mr. Selecky discussed the basic purpose and importance of a COSS like that performed by Mr. Ross in this case.  See, 2 Tr 268.  He testified that he reviewed that COSS, paying particular attention to the “resulting cost of service of the production, transmission, and distribution allocation methods proposed by Consumers.”  2 Tr 270.  His review confirmed that the utility’s COSS (which was based on data used by the Commission in Case No. U-17087 to establish the company’s
existing rates) was revenue neutral, and then went on to provide additional recommendations and conclusions. See, 2 Tr 270-276.

For example, Mr. Selecky recommended that the Commission adopt the 4CP 100/0/0 method for allocating fixed production costs that Consumers proposed in this case, although noting that use of a 3CP structure would also be appropriate. See, 2 Tr 271-272. According to him, this recommendation is based on his review of Consumers’ monthly maximum demand peaks over the ten-year period from 2004 through 2013, which showed that summer peaks are dominant and that they thus drive the utility’s need for new capacity. See, Id. Mr. Selecky presented Exhibit AB-1 to support this analysis. He further noted that MISO uses a single coincident peak as the starting point to determine each utility’s capacity reserve requirements and future capacity needs, and went on to state that this peak tends to occur in June or July. He thus testified that:

Since the MISO summer peak drives Consumers’ need for capacity and causes [its] ratepayers to incur cost to meet Consumers’ capacity requirement, it is appropriate that these fixed capacity-related costs should be allocated to ratepayers based on peak demand or kW, and not energy or kWh. 2 Tr 273.

Turning his attention to transmission-related expenses, Mr. Selecky supported Consumers’ claim that transmission costs should be allocated based on a 12CP 100/0/0 method, mirroring the way MISO charges Consumers for these costs. See, 2 Tr 274-275. Moreover, he noted that if the FERC changes MISO’s transmission cost allocation methodology to use a 4CP structure, he would recommend that Consumers follow suit. See, 2 Tr 275. Mr. Selecky concluded his direct testimony by asserting that,
notwithstanding Consumers’ preference to initiate any changes arising from this proceeding until December 1, 2015, the new rates “should be effective with the Final Order,” instead of making customers wait for the rate realignment. 2 Tr 76.

In his rebuttal testimony, Mr. Selecky addressed Staff’s proposal to allocate fixed production costs through the use of a 4CP 75/0/25 methodology. According to Mr. Selecky, that methodology would not be appropriate because the utility’s fixed production costs “[do] not vary with the amount of energy produced,” and, further, that a utility incurs those costs solely “to meet its system demands.” 2 Tr 282. In addition, he notes that although the NARUC Manual “does discuss allocation methods that can rely on energy allocators,” it “does not specifically classify any of those costs as really energy-related.” 2 Tr 283.

Mr. Selecky went on to rebut an assertion by one of the Staff’s witnesses to the effect that if a customer class increases its energy usage without increasing the utility’s electric demand, it should see an increase in the amount of its allocated production-related costs, lest it receive electric service on a “cost-free” basis. 2 Tr 283; citing 3 Tr 437. Specifically, Mr. Selecky disputed that under his and Consumers’ proposed 4CP 100/0/0 production cost allocation method, a customer class increasing its energy usage but not its demand would see no increase in its cost allocations. Rather, he testified, that customer class would see an increase in the variable costs associated with the energy. See, 2 Tr 283. He also testified that, in his opinion, passing on fixed production costs to any such customer would violate cost-causation principles because the customer did not cause the utility to incur any additional fixed production costs. See, Id. Mr. Selecky further asserted that using a 100% demand allocator for
production-related fixed costs--as he and Consumers propose--is consistent with Governor Snyder's overall energy policy, citing the Executive Summary of the Workgroup Report, which is set forth on page 1 of Exhibit A-14, and further characterized energy allocators as being “judgmental” in nature. 2 Tr 284.

Mr. Selecky concluded his rebuttal by stating that another reason exists for adopting the utility’s proposal to allocate all production costs on a 4CP 100/0/0 basis, specifically that:

Consumers in its “Report on Summer 2014-2016 Capacity Plan” filed with the Commission in Case No. U-17523 on March 28, 2014 stated that [it] will purchase additional capacity through [MISO] in late March of each year that was studied. In that document, Consumers indicates that its summer capacity purchases in 2015 and 2016 will be 111 MW and 404 MW, respectively. This clearly demonstrates that Consumers has capacity needs that are driven by its summer peak, and price signals should be sent through cost of service and rate design.

Finally, the Commission in Case No. U-17751 has opened a matter for the investigation into electric supply reliability plans for Michigan electric utilities for the years 2015 through 2019. The Commission in its Order in that case stated that this investigation is brought about by capacity shortfalls in Michigan as early as 2016.

2 Tr 284-285.

Based primarily on the direct and rebuttal testimony provided by Mr. Selecky, as well as related testimony offered by Consumers’ three witnesses, ABATE argues that “new cost allocation methodologies are needed to better ensure that rates are equal to cost of service and support affordable and competitive rates for all customer classes.” ABATE’s initial brief, p. 1. ABATE further contends that such changes are needed to “reach the Governor’s stated goal, which is to ensure energy-intensive industries can choose Michigan for job and investment decisions and to better compete.” Id.
In support of these assertions, ABATE claims that the fundamental underlying principle of the present case is that a utility’s cost allocation and the electric rates arising therefrom must meet the firm energy demand of all of its customers. See, Id. As a result, ABATE continues, the focus of cost allocation must be on each customer's contribution to peak demands or, in the case of transmission-related expenses, based upon how the FERC assigns transmission costs to retail utilities like Consumers. In addition, it contends, another “important consideration in supporting a change in the allocation methodology” is a recognition that whatever methodology is adopted “should not penalize high-load factor customers” (such as ABATE’s members). Id., p. 2. In this regard, ABATE argues that moving Consumers’ allocation of production-related costs to a 4CP 100/0/0 method would remove what it contends is “the current allocation penalty” imposed upon its members because the new allocation structure would use “pure demand and not a combination of demand and energy, which allocates more costs to high-load factor customers because of their higher energy usage.” Id. As for the allocation of transmission-related expenses, ABATE supports adopting the utility’s proposal to use a 12CP 100/0/0 allocation methodology, primarily on the grounds that it matches the allocation method used by the FERC for MISO’s capacity reserve requirements. See, Id., p. 8.

For these and other reasons, ABATE suggests that the Commission (1) adopt Consumers’ proposed 4CP 100/0/0 and 12CP 100/0/0 allocation methodologies for production- and transmission-related costs, respectively, (2) authorize the utility to make its requested re-classification of customer assistance expense, (3) reject MEC’s ratemaking proposals in their entirety, (4) ignore the Attorney General’s various
proposals, and (5) likewise reject both the Staff’s suggested 4CP 75/0/25 production
cost allocation method and its recommended change with regard to how UAEs are
assigned to the various rate classes. See, ABATE’s reply brief, pp. 8-9.

C.  **Energy Michigan**

Energy Michigan presented direct testimony from Alexander J. Zakem, an
independent energy consultant who has held managerial positions with Quest Energy
(an alternative energy supplier in Michigan) and The Detroit Edison Company (now DTE
Electric).

Mr. Zakem’s testimony focused almost exclusively on how Consumers’ UAEs
should be allocated for recovery by the utility. 17 Currently, Mr. Zakem noted, the utility
“allocates total uncollectibles dollars to various rate classes by the number of customers
in each rate class,” and then includes them as a portion of the distribution expense
reflected in its workpapers as “Customer Accounts Expense.” 3 Tr 623. He stated that
this methodology of recouping approximately $30.5 million per year in UAEs is not
equitable, and must be changed for two reasons.

First, Mr. Zakem pointed out that customer classes do not cause UAEs, but--
rather--individual customers do. See, 3 Tr 624. Put another way, he continued:

[T]he amount of uncollectibles of a class is not determined by the electric
use characteristics of the class. At the same time, the other customers in a
rate class who pay their bills do not cause uncollectibles. Consequently, it
is illogical to allocate uncollectibles--and charge a particular customer--

17 Mr. Zakem also expressed concern regarding the visual aspect of one of Consumers’ exhibits
(specifically, Exhibit A-11) because it “stacked on one another” the 2013 peak demand load profiles of the
residential, secondary, and primary rate groups in a way that he found to be at least somewhat deceptive.
3 Tr 632-634. However, either because Mr. Zakem submitted his own exhibit providing other ways to
graphically compare those load profiles (admitted as Exhibit EM-4) or Mr. Ross offered--by way of
rebuttal--a chart depicting the data in an easier-to-understand fashion, Energy Michigan elected not to
pursue this matter further.
based simply on how many other customers are in the same group as the particular customer.

Id. Moreover, he testified that the outcome of Consumers’ existing UAE allocation structure is inequitable, as reflected by the fact that “the entire Primary class receives an allocation of only $65,000 out of $30,505,000 total uncollectibles,” yet is expected to provide the utility with over $1 billion in total annual revenues. Id., citing Exhibits EM-2 and EM-3. Although it is true that Consumers must recover its UAEs, Mr. Zakem went on to state that:

Uncollectibles are a company-wide overhead, independent of the electric use of rate classes. Compensation for [UAEs] that is shifted to the customers who pay their bills should be independent of the number of customers in rate classes. Thus the [UAEs] should be allocated in a general and equitable way to all rate classes to be paid by all customers.

3 Tr 624. To fix this problem, he recommended that the allocation of Consumers’ UAEs be based on “total cost-of-service,” which he stated is the same method that is used to “allocate the discounts for the Large Economic Development Rate, Senior Citizens, and Income Assistance.” Id. His proposed structure is, Mr. Zakem continued, “the same method that DTE Electric currently uses to allocate [its] uncollectibles. Id.

Second, Mr. Zakem testified that Consumers unreasonably includes all of its UAEs in the distribution portion of its customers’ bills. This makes no sense, he claims, because “if a customer does not pay a bill, that [unpaid] bill includes both distribution and power supply charges,” and thus the “distribution portion should be included in the distribution rates, and the power supply portion should be included in power supply rates.” 2 Tr 626 [emphasis in original]. Mr. Zakem further testified that including all UAEs only in distribution rates, as Consumers presently does, is “unfair to both bundled and ROA customers” because:
It means that bundled customers are not being charged fairly for the separate distribution and power supply services; and it means that customers of other power suppliers – Alternate Electric Suppliers – who take only distribution service from [Consumers] are compensating [the utility] for its power supply customers who do not pay their power supply charges.

3 Tr 627. To show that this does not need to be the case, he cited the Commission’s order in Case No. U-17087, noting that by approving the settlement in that proceeding, the Commission essentially allocated the Rate E-1 subsidy to both power supply and distribution components. Mr. Zakem thus recommended that the Commission direct Consumers to split its UAEs between distribution charges and power supply charges in “the same proportion as the overall weighted average of distribution and power supply costs” that the utility’s total UAEs represent. 3 Tr 631.

Consistent with its witness’s testimony, Energy Michigan requests that the Commission order Consumers to change its current methodology for allocating UAEs to (1) adopt the total cost-of-service method espoused by Mr. Zakem, and (2) separate the allocation of those uncollectibles in separate distribution and power supply portions.

See, Energy Michigan’s reply brief, p. 4.

D. Hemlock

Hemlock offered direct and rebuttal testimony from Michael P. Gorman, a public utility regulatory consultant and Managing Principal with Brubaker & Associates, Inc., an energy, economic, and regulatory consulting firm. This direct testimony essentially focused on three areas.

First, Mr. Gorman expressed strong support for Consumers’ proposals to shift its total company production-related cost allocation method to a 4CP 100/0/0 structure, as
well as to implement a 12CP 100/0/0 allocation method with regard to all transmission-related costs. See, 3 Tr 351. His support for those two proposals was based largely on his belief that retention of the existing 50/25/25 allocation structure for these two types of expenses would be “unreasonable and inconsistent with the balanced findings of the participants in the [MEDC] Workgroup,” as set forth in the Workgroup Report received into evidence as Exhibit A-14. Id. Specifically, he asserted that:

To the extent that the Commission accepts parties recommendations that deviate from the consensus recommendations reached in that report, cost allocation between classes can be impacted, utilities’ resource planning can be impacted, and Michigan utility customers’ ability to make capital investment plans for their own businesses can be put at risk. All of these factors can work to the detriment of retaining and attracting new industrial load for Michigan, which can erode the opportunity for retaining and increasing the number of high-paying jobs in Michigan.

3 Tr 354.

Second, Mr. Gorman testified that, notwithstanding his support for the utility’s proposed adoption of the new production- and transmission-related cost allocation method’s noted above, he had serious concerns regarding the manner in which the company seeks to design its GPD rate. In explaining his areas of concern, he stated that:

1. Consumers’ proposed rate design for GPD Customer Voltage Level 1(GPD-CVL-1) has an unreasonably low demand charge, and high energy charge relative to Consumers’ cost of service for this class. This rate design will create intra-class cost subsidization between GPD customers which is not consistent with Michigan’s cost-based rate objectives.

2. Consumers’ proposed Substation Ownership Credit for GPD customers is too low and will result in customers who own their own substations subsidizing Consumers’ cost of distribution services provided to other customers. Consumers’ failure to produce a reasonable Substation Ownership credit results in distribution cost subsidization across and within rate classes.
3 Tr 354-355. Although conceding that it is an improvement over the current 50/50 intra-class allocation structure, Mr. Gorman asserted that the utility’s proposal to “recover approximately 75% of its capacity-related charges through its On-Peak Demand charge” and about 25% through an energy-based component “still produces intra-class cost subsidization between high load factor and low load factor customers,” and claimed that the Commission should order Consumers to “more accurately” adjust (1) its demand charges to recover all demand-related expenses and (2) its energy charges to “recover only its fuel, purchased power energy, and variable operating costs.” 3 Tr 355. Turning to the utility’s proposed Substation Ownership Credit for Rate GPD customers that “own their substations and where the substation costs are recovered in a facilities agreement with Consumers,” Mr. Gorman claimed that leaving the credit at its current level of $0.30/kW-month of distribution demand—as suggested by the utility—does not provide full recognition of the credit those customers should receive if Consumers’ costs of distribution service were more properly allocated. 3 Tr 358; See also, 3 Tr 359-362. He thus asserted that, for GPD-CVL-1 customers, the cost of distribution service should be adjusted to reflect a 100% credit for substation ownership, with the distribution costs otherwise recovered by that rate subclass essentially shifted to other customers. See, 3 Tr 362. However, Mr. Gorman further stated that, if the Commission prefers to leave the Substation Ownership Credit at the $0.30/kW-month level requested by Consumers, the utility should concurrently be

18 Among those called upon to bear a larger share of Consumers’ distribution costs to offset the 100% Substation Ownership Credit Mr. Gorman proposed for application to GPD-CVL-1 customers (such as Hemlock) were customers taking service under Rates GPD-CVL-2 and GPD-CVL-3. See, 3 Tr 362-364.
“directed to adjust distribution bill units for customers that own substations or have facilities agreements for dedicated substations.” 3 Tr 364. Specifically, he asserted:

Consumers should not include distribution demand bill units in its cost of service and should not charge customers for distribution service through a tariff if they pay for service by a contract rather than tariff service. In this instance, the distribution demand billing units for the meters in the customer-owned substations should be excluded from Consumers’ [COSS] used to set rates, and no charge should be applied to substations’ distribution billing units for metered consumption in the dedicated substations, where Consumers’ cost is fully recovered in a facilities agreement. This will ensure that Consumers fully recovers its cost of distribution service from customers for which the cost is incurred, and will eliminate any subsidization between customers.

3 Tr 364-365.

The third area addressed in Mr. Gorman’s direct testimony concerns his recommendation that Consumers be directed to create a high load factor rate classification within Rate GPD when designing rates to be adopted in its next general electric rate case. See, 3 Tr 365. In support of this recommendation, he asserted that:

First, a high load factor designation would more accurately allow for the allocation of production capacity and energy costs to high load factor customers.

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Second, separating these customers into a high load factor class, and having similar interests in designing capacity and energy based prices, will eliminate any subsidization between Rate GPD customers and high load factor customers.

3 Tr 365-366. Doing so, he continued, “should allow for more accurate allocations of costs to high load factor customers,” while also providing the utility with the flexibility needed to “accurately design rates to recover capacity costs in demand charges, and energy costs in energy charges.” 3 Tr 366. Moreover, Mr. Gorman concluded, to the extent that these customers are able to undertake energy conservation, invest in on-site generation, or take other steps to manage their load, a more accurate price signal
(which he assumed would result from implementation of a high load factor rate class) "would encourage these customers to reduce demand during peak periods, and reduce peak period energy consumption." 3 Tr 367.

Mr. Gorman also provided rebuttal testimony responding to the presentations offered by witnesses for the Staff and the Attorney General concerning Consumers’ production-related cost allocation proposal (i.e., its request to replace the existing 4CP 50/25/25 structure with the 4CP 100/0/0 methodology) when performing its COSS.

Mr. Gorman took issue with several statements made by the Staff’s witness on this matter, in which that witness recommended adoption of the 4CP 75/0/25 allocation method for Consumers’ production-related expenses. Chief among them were the Staff witness’s statements to the effect that “a pure demand capacity allocation factor” (like that proposed in this particular case by Consumers, and strongly supported by both ABATE and Hemlock) is not an appropriate way to assign a utility’s production costs, and that a utility must “also consider the best way of meeting customers’ energy use for the entire year,” as opposed to focusing on peak-usage days only. 3 Tr 375. Moreover, Mr. Gorman rebutted that witness’s reliance on the fact that the Commission has “used an energy element in allocating production capacity costs” since at least 1976 as support for “the Staff’s proposal to continue to use energy as a component in developing the production capacity allocation factor.” 3 Tr 376.

Concerning that witness’s reliance on past Commission practice, Mr. Gorman pointed out that the August 5 order “specifically directed Consumers to propose modifications to existing cost allocation methods and rate design methods,” as
necessitated by the passage of Act 169.\textsuperscript{19} \textit{Id.} He continued by asserting that, as noted by the utility:

\textit{[T]he Commission has the authority to: (a) modify the 50/25/25 production allocation and transmission allocation methodologies to better ensure rates are equal to cost of service; and (b) explore different methods for allocation of production, transmission, distribution, and customer-related costs, and overall rate design, based on cost of service, that support affordable and competitive electric rates for all customer classes.}

3 Tr 376-377. According to Mr. Gorman, this witness’s reliance on past Commission actions “fails to respond to the Commission's request for examination of more accurate and current cost of service methods in this case.” 3 Tr 377.

Mr. Gorman continued his rebuttal of the Staff’s witness’s statements regarding the allocation of production-related costs by referring to the Workgroup Report, where Mr. Gorman pointed out that:

The [MEDC Workgroup] examined the production cost allocator recommended by the Staff in this case as well as the 4CP 100% demand allocation recommended by Consumers and the 50/25/25 used in Consumers’ last rate case. The [MEDC Workgroup] concluded:

\textbf{Production Costs}

Based on the COSS scenarios run by the utilities, the participants agree [that] the production cost allocator should be changed from a 4CP/12CP 50%/25%/25% production allocator to a uniform 4CP 100% demand production allocator. The 4CP allocator (which is based on a class’ contribution to the utilities’ highest four monthly coincident peaks) is the correct allocator to utilize for allocating fixed production costs.

3 Tr 377-378, citing Exhibit A-14, p. 8. Moreover, he continued, the Staff’s proposed production cost allocator “is unreasonable” because:

\textsuperscript{19} Likewise, albeit not mentioned by Mr. Gorman, the Commission also issued an order on August 5, 2014 directing DTE Electric to make a similar cost allocation and rate design filing. \textit{See}, the Commission’s August 5, 2014 order in Case No. U-17689.
1. Staff’s proposed production capacity cost allocator will not allocate to load low [sic] factor customers enough capacity to meet those customers’ peak capacity demands. Therefore, under Staff’s methodology, low load factor customers (which included residential customers) will not pay the full cost of capacity needed to provide them with firm service.

2. Staff’s proposed production capacity cost allocator does not produce a symmetrical and balanced allocation of production capacity costs and production energy costs across rate classes. Symmetrical allocation of production costs recognizes that increased capacity costs generally align with lower energy costs. Conversely, reduced capacity costs generally align with increased energy costs. However, Staff’s proposed production cost allocator will overstate the capacity costs of high load factor customers and understate the capacity costs of low load factor customers, without modifying the energy cost allocation between these two customer classes. This creates an asymmetrical allocation of production capacity and energy costs across these rate classes.

3 Tr 378. After defining the difference between production capacity and production energy, stating that customers can have comparable energy demands with different capacity demands, Mr. Gorman addressed the Staff witness’s statement that use of a strict 4CP 100/0/0 method to allocate production-related costs a customer that raises its energy usage without increasing its demand use would get additional production service at no cost. See, 3 Tr 380. From there, he provided rebuttal testimony (based on three different scenarios) that he contends confirms the status of the 4CP 100/0/0 method as providing “the most accurate cost allocation to a customer class.” 3 Tr 389.

Turning to testimony provided by the Attorney General’s witness, Mr. Gorman’s rebuttal testimony expresses disagreement with that witness’s assertions that (1) the 4CP 100/0/0 production cost allocation structure proposed by Consumers in this case “has not been sufficiently studied regarding the impact on customers and should therefore be rejected” and (2) the utility’s determination of the need for new production capacity “is not determined by demand alone, but rather is determined by several
factors including the total cost of production,” through a combination of both base load and peaking units. 3 Tr 390. In addition, Mr. Gorman asserted that the Attorney General’s witness failed to address the fact that Consumers has certain obligations as a “Load-Serving Entity (LSE) in MISO,” which therefore requires that the utility “invest in an amount of production capacity needed to serve its highest customer load,” based on a 1CP demand basis, plus reserve margin. 3 Tr 391.

Mr. Gorman concluded his rebuttal by noting that Consumers “considers many factors”—like “investing in enough capacity to meet customers’ peak demand, and minimizing its cost of production service to its customers” (including recognizing the potential penalties imposed for failing to satisfy MISO’s demands)—when determining how to best allocate its production-related costs across various rate classes. 3 Tr 392. Because the utility’s proposed 4CP 100/0/0 structure would, upon consideration of all those factors, result in the best match to cost of service, he feels that it should be adopted in this case. See, 3 Tr 392-393.

Based largely on Mr. Gorman’s direct and rebuttal testimony, Hemlock asserts that the Commission should take the following four steps: 20 (1) accept Consumers’ request to switch to the 4CP 100/0/0 production cost allocation structure set forth in its application, thus rejecting calls from Staff and Attorney General witnesses, respectively, to either adopt a 4CP 75/0/25 methodology or simply retain current 4CP 50/25/25 structure; (2) adopt the utility’s proposal to allocate its transportation-related costs by

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20 Although Mr. Gorman provided a detailed analysis concerning the need for Consumers to revise its Substation Ownership Credit, which currently rests at $0.30 per/kW-month, it has now withdrawn that requested change to the utility’s rate design. See, Hemlock’s initial brief, pp. 10-11. According to Hemlock, its decision to withdraw its proposal in the present proceeding is “so as to allow more time to work with [Consumers] and the Staff to develop a mutually acceptable proposal for submission in Consumers’ pending rate case,” specifically Case No. U-17735. Id., p. 11.
way of the 12 CP 100/0/0 method; (3) reject the company’s proposed re-design of the demand and energy rates to be applied to its GPD Rate class on the grounds that Consumers’ proposal only recovers 75% of its capacity-related costs through capacity-related charges--which is not fully consistent with its cost of service--and that one of its own witness’s testimony shows that assigning 100% of those costs to capacity charges would produce rates that more accurately reflect cost causation;\(^2\) and (4) direct the utility to include a high load factor sub-class within the GPD rate class as part of its next general electric rate case filing. See, Hemlock’s initial brief, pp. 4-10 and 11-13.

In addition, Hemlock contends--among other things--that, with regard to the overall structure of Rate GPD, information provided from Consumers appears to indicate that a full cost of service-based design for that rate class could benefit more industrial customers than it would serve to disadvantage, and re-emphasizes that the utility’s proposed design for Rate GPD would continue to produce intra-class subsidization. See, Hemlock’s reply brief, pp. 6-11. Finally, it asserts that adopting the Staff’s suggested 4CP 75/0/25 production cost allocation structure based on such factors as “history” and “tradition” (in the form of past Commission decisions) is patently inconsistent with Act 169’s “statutory mandate for change,” that the Staff is wrong in its belief that the 4CP 100/0/0 could allow some large customers to “use more energy without being allocated any additional costs,” and MEC’s assertion that increasing

\(^2\) Specifically, Hemlock asserts that the company’s witness with regard to rate design, namely Ms. Collins, explained during cross-examination that one of the reasons why Consumers is proposing to only assign 75% of the Rate GPDs’ collective capacity costs “to the un-peaked demand rates” instead of allocating the entire 100% based solely on those customers’ respective demand levels is because making the transition from the current 50% assignment level to 100% “all at once would result in rate increases for low load factor customers that, in her opinion, would be unreasonably high.” Hemlock’s initial brief, p. 9, referencing 2 Tr 105-106.
residential rates by a mere 2.5%--as Consumers contends would result from the adoption of all of its cost allocation and rate design proposals set forth in this case--“falls far short of proving that the resulting rates will be unaffordable.”  _Id._, pp. 13, 20, and 26-27.

E.  Staff

As mentioned earlier, the Staff presented testimony and exhibits from three witnesses in this case.  These consist of Charles E. Putnam (a Departmental Analyst in the Rates and Tariffs Section of the Commission’s Regulated Energy Division, who presented direct testimony only), Mark J. Pung (also a Departmental Analyst in that Division, and who provided both direct and rebuttal testimony), and Nicholas M. Revere (the Division’s Manager, who offered only rebuttal testimony).

Mr. Putnam offered detailed testimony regarding Consumers’ proposed changes in cost allocation that were used as inputs to the utility’s most recent COSS.  In that regard, he stated that there were four proposed changes that he sought to address:

1) Changing the weighting of the production cost allocator from 4CP 50/25/25 to 4CP 100/0/0;
2) Changing the weighting in the transmission allocator from 12CP 50/25/25 to 12CP 100/0/0;
3) Changing the allocation of the highest voltage distribution-related rate base and its associated expenses to a common allocator based on peak demand at generation (essentially changing the allocation of distribution costs from rate classes to voltage classes); and
4) Reclassifying portions of Other O&M expense through the historical allocation process based on the removal of certain expenses (namely $49 million in LIEEF and EO costs) from FERC Account 908 and their inclusion in other cost of service line items.

See, 3 Tr 434.  Of those four proposed changes, Mr. Putnam indicated that the Staff accepts items 2 and 3, but takes issue with items 1 and 4.  See, 3 Tr 435.
With regard to the first proposed change, Mr. Putnam testified that Staff does not agree with DTE Electric's proposal to base the production cost allocation entirely on 4CP demand, which measures demand over only four hours of the year, consisting of the peak hour recorded during each summer month from June through September. See, Id. After discussing the components of the current allocation method that Consumers proposes to delete (namely, the 25% on-peak weighting that looks at 4,000 peak hours in a year, and the 25% total energy use that is based on energy use over the entire year), he testified that Staff does not fully agree with Mr. Ross’s assertion to the effect that the utility’s capacity planning function is designed solely to meet its customers’ peak demand requirements. 3 Tr 436; citing 2 Tr 127. According to Mr. Putnam:

[I]t is the Staff’s position that capacity is only one factor considered when planning for energy production. The company must also consider the best way of meeting the energy use for the entire year.

* * *

Page 1 of Exhibit S-3 shows information taken from the Company’s 2013 annual report regarding its generating plant statistics. Staff grouped the generating assets based on hours connected to load as either a base load or other than base load unit. The cost per kW of capacity is $1,000 for the base load units and only $277 for the other units. If the company was only planning to meet capacity needs, why did [it] spend almost 4 times as much for a kW of capacity for the base load units as compared to the other units? The answer is simple. The base load units are traditionally the least expensive way to meet the energy needs for all 8,760 hours of the year due to lower operating costs.

Id.

Moreover, Mr. Putnam testified that although the Staff agrees with Consumers that looking at “each class’s contributions to the summer peak demands is a reasonable way to allocate demand-based costs and reflects cost causation,” both he and the Staff
disagree with the utility’s implication that, under the current 50/25/25 allocator, “customer energy profiles are also being used to allocate demand-based costs.” 3 Tr 437. According to him, it is the Staff’s position that the energy profiles are not being used to allocate any demand related costs, but rather are only being used to allocate energy-related costs. See, Id. Thus, he stated, these energy profiles are:

[B]eing used to allocated energy related costs. Under Mr. Ross’s 100% demand allocation proposal, if a customer increased its energy usage without increasing demand, it would see no increase in the allocation of production-related costs. The customer class would [thus] receive increased service from production assets, but the class would not receive any increase in allocated production costs. In effect, with regard to production assets, this increase in service is cost-free. This is [he asserts] a violation of cost of service principles.

2 Tr 437.

Mr. Putnam went on to assert that the Staff views production assets as providing both energy and capacity, and that--therefore--it asserts that “there should continue to be some recognition of both energy use and capacity use in the allocation factor.” Id. He then provided a review of the history of Commission decisions addressing production cost allocation, and testified that for at least the past 38 years, every COSS adopted in Consumers’ electric’s rate cases has had 25% of the production allocator determined by total energy. See, 3 Tr 437-438. He also presented an analysis of the generating statistics from Consumers’ 2013 annual report in his Exhibit S-3, and an analysis of Consumers’ 8760 reports provided in discovery in his Exhibit S-4, and asserted that--based on the generating statistics contained in these reports--during 2013, the year most closely related to the test year underlying the company’s current rates, base load energy was 62% of the total energy for the year, and 32.5% of the maximum capacity needed during the year. See, 3 Tr 438. From the 8760 reports, Mr.
Putnam noted, the Staff determined that 72.9%, or approximately $3.1 billion of Consumers’ total production plant, is base load in nature. See, Id. As such, the Staff concludes that if 72.9% of total generating unit cost arises from base load assets, and if 32.5% of the utility’s maximum energy consists of base load energy, than—at a minimum—23.7% (72.9% x 32.5%) of the company’s production cost-related allocator should be based on total energy. See, Id.

Mr. Putnam went on to testify that the Staff views the 23.7% figure “as a rough calculation to determine if the historical 25% energy allocation is reasonable,” and has concluded that it is. 3 Tr 439. Then, citing to Case No. U-4771, Mr. Putnam testified that in keeping with the tradition established in that proceeding, the Staff recommends that the remaining 75% be based on demand, all of which leads the Staff to propose for adoption in this proceeding of a 75% 4CP demand, 25% energy production cost allocation methodology, also expressed as a 4CP 75-0-25 structure. See, Id. Regarding the on-peak energy allocator that receives a 25% weighting in the current 50/25/25 method, Mr. Putnam testified that Staff is not abandoning the concept (as “the inclusion of on-peak energy as some portion of the production allocator has merit”), but is simply not proposing to include it in the present case. Id.

Mr. Putnam also addressed Consumers’ proposed allocation of customer assistance expenses, such as those included in FERC Account 908. In doing so, he started by pointing out that (as noted by Mr. Ross) the initial COSS drawn from Case No. U-17087 allocated $52,425,000 of FERC Account 908 costs on the basis of billed sales. See, Id. However, he continued, the utility now contends that 94% of those expenses (specifically, those related to LIEFF and EO costs—or $49,114,000) should be
removed from customer assistance expense and allocated on “other cost of service line items.” Id. According to Mr. Putnam:

The reclassification in customers assistance expense is supported by Company witness Ross. Mr. Ross explains that there was an error in the original allocation of test year [Other] O&M expenses outside of the COSS to determine COSS line inputs. The original allocation was based on historic costs. The [LIEEF and EO] costs were included in error when determining the original allocation. To be consistent, the LIEEF and EO costs need to be removed from the historic costs because LIEEF and EO costs were not included in the [Case No.] U-17087 COSS. If the LIEEF and EO costs had been removed, there would have been different amounts allocated to COSS input lines.

3 Tr 440, citing 2 Tr 131-132. Although agreeing with Consumers that the underlying reasoning for this proposed change is sound, Mr. Putnam went on to assert that such a change should not be made in this case.

According to Mr. Putnam, the appropriate time and place for making the utility’s proposed change would have been in Case No. U-17087, as opposed to the present proceeding. See, Id. In support of this assertion, he noted that the Staff “looks at the combined effect” of the allocation of customer assistance costs (like those arising from the LIEEF and EO programs), on the one hand, and UAEs, on the other. Id. Had the company made its proposed change regarding the allocation of those two customer assistance expenses in Case No. U-17087, he continued, the Staff “would have proposed that a corresponding change be made in the allocation of UAEs.”22 Id.

22 Mr. Putnam pointed out that the Staff has actually made this argument in at least one of Consumers’ previous rate cases. Specifically, he noted that in Case No. U-16794, the Staff argued that:

Customer assistance and uncollectible expenses are part of the overall cost of doing business for Consumers. These costs are not caused by the actions of any given ratepayer class, and therefore, the burden of these costs should be spread equitably over all ratepaying classes. When customer assistance expense is combined with uncollectible expense, of the combined total under the Staff’s methodology, 57% is being allocated to the residential class and 24% to the primary class. If a pure number of customers allocation is used [as would occur under the utility’s current proposal], the resulting
With regard to this issue, Mr. Putnam went on to note that the utility’s $30,505,000 in UAEs are currently allocated based on the number of customers in each rate class. With regard to this allocation, he pointed out that:

In the [NARUC Manual's] discussion of UAEs, two methods are mentioned. “Uncollectible Accounts . . . may be directly assigned to customer classes. [However] some analysts prefer to regard uncollectible accounts as a general cost of performing business by the utility, and would classify and allocate these costs based upon an overall allocation scheme, such as class revenue responsibility.”

* * *

Staff would propose that UAEs be allocated on an overall allocation scheme consistent with the NARUC Manual. Staff would use the same allocator currently used to allocate customer assistance expense, which is based on billed sales.

3 Tr 441-442 [citations omitted]. Mr. Putnam went on to point out that if this change in the allocation of UAEs were to be implemented in the manner suggested by the Staff, the revenue requirement for Consumers' residential rate class would drop by $24 million, while those of the Secondary and Primary classes would rise by $4 million and $19 million, respectively. See, 3 Tr 442. In comparison, he noted that adopting the utility’s proposed re-allocation of customer assistance expense (e.g., its annual LIEEF and EO costs) would, according to Mr. Ross, produce “an increase in the Residential class revenue requirement of $18 million, no material impact to the Secondary class, and an $18 million reduction to the Primary class revenue requirement.” Id., citing 2 Tr 132, lines 12-14.

percentages would be 87.7% to residential, and 0.2% to the primary class. Staff maintains that its methodology spreads the burden of these expenses fairly among all the classes.

3 Tr 440-441; citing Staff’s initial brief in Case No. U-16794, p. 61.

U-17688
Page 53
Mr. Putnam concluded his testimony by describing how the Staff prepared and used its own COSS for this proceeding. Specifically, he noted that the Staff (1) began with the COSS provided by Consumers’ witness Ross, (2) accepted the utility’s new treatment of the company’s highest voltage distribution costs and the allocation of transmission-related expenses using Consumers’ suggested 12CP 100/0/0 allocation methodology, (3) substituted its preferred 4CP 75/0/25 production cost allocator in place of the 4CP 100/0/0 allocator proposed by utility, and (4) refrained from making any change to the treatment of either customer assistance expenses or UAEs. See, 3 Tr 442-443. According to Mr. Putnam, the Staff then provided its COSS (as set forth on Exhibit S-1) to Mr. Pung for use in designing rates, but with the assumption that this COSS would ultimately be revised to incorporate “any decision that is made by the Commission that would effect the COSS.” 3 Tr 443.

By way of direct testimony, the Staff’s second witness, Mr. Pung: (1) sponsored the Staff’s rate design proposal; (2) addressed general policy issues, such as the allocation of capacity costs for the MMPP rate class, the allocation of interruptible capacity costs, Consumers’ proposal to recover 75% of its Rate GPD customers’ capacity costs through the on-peak demand charge, and the utility’s suggested revisions to the Rate GPD delivery charges; (3) provided the Staff’s position regarding how the cost allocation changes proposed in this proceeding would affect future rate design; and (4) addressed the information requirements outlined in the August 5 order. See, 3 Tr 457. Among other things, exhibits developed and presented by Mr. Pung set forth (on Exhibit S-2, Schedules F-2.1a and F-2.1b) the computation of test-year power supply revenue based on the Staff’s COSS--both with and without Rate E-1 included--
“broken down by rate schedule.” 3 Tr 458. Moreover, he noted that Exhibit S-2, Schedule F-3 provides the rate calculations and revenue detail by rate schedule, including billing determinants, the existing rates (as establish by the Commission’s adoption of the settlement agreement in Case No. U-17087), the revenue generated by those existing rates, the Staff’s proposed rates, the revenue that would be generated by the Staff’s proposed rates, and both the average dollar amount and percentage increase or decrease arising from the proposed rate changes. See, 3 Tr 459.

Mr. Pung responded to the informational requirements imposed by the August 5 order by testifying, among other things, that:

The estimated impact of Staff’s proposals is as follows: revenue to be collected from the residential class would increase by approximately 0.3%. This is also the increase an average residential customer would see on their annual bill. Revenue to be collected from the commercial/secondary class would decrease by approximately 2.1%. The average secondary customer would also see this percentage decrease in their annual bill. Revenue to be collected from the industrial/primary class excluding [Rate] E-1 would decrease by approximately 2.1%. This is also the decrease an average non Rate E-1 industrial/primary customer would see on their annual bill. Revenue to be collected from the other/lighting class would decrease by approximately 3.3%. This is also the decrease an average other/lighting customer would see on their annual bill.

3 Tr 460-461. Turning to other matters raised in this proceeding, he pointed out that the Staff (1) agrees with Consumers that no changes in rate structure are needed at this time for the utility’s Residential and Secondary rate schedules,23 (2) concurs with the company that, because capacity costs are not currently being allocated to MMPP customers in the COSS, its proposed adjustment in the corresponding rate design

23 In this regard, Mr. Pung went on to note that although there are currently no structural changes being proposed, the actual rates for Consumers’ Residential and Secondary customer classes have been changed in his exhibits “to reflect the Staff’s cost of service proposals and the expiration of the Large Economic Development Rate E-1.” 3 Tr 461-462.
model should be made, (3) supports Consumers’ proposed method for allocating capacity costs to GPD customers that take interruptible service under that rate’s GI Provision, as well as its suggestion to increase the summer Interruptible Credit from $6.00/kW to $7.00/kW, (4) agrees with the utility’s proposal to increase the portion of capacity costs collected from Rate GPD customers through the On-Peak Demand Charge from its existing 50% level to a more reasonable 75% level, which Mr. Pung asserted would both better match cost causation and result in high load factor customers seeing a lower average rate, and (5) supports the company’s suggestion to revise the delivery charge structure for Rate GPD by eliminating the distribution charge for this rate class, retaining the current $100/month System Access Charge, and collecting all remaining delivery costs through the Maximum Demand Charge, all of which would serve to eliminate the imposition of a distribution energy charge for the GPD rate class.24 See, 3 Tr 462-465.

Mr. Pung concluded his direct testimony by asserting that, because the Staff recommends “allocating more in the way of fixed production costs on the basis of summer demands (compared to the Company’s current 50-25-25 allocation method),” it is important to ensure that customers “receive the appropriate price signal with rates charging the cost causative element.” 4 Tr 465. According to him, the appropriate price signal can best be sent by “pricing the activity which causes the cost (demand at system peaks) appropriately, which has not previously been the case for many secondary customers.” 4 Tr 465-466. However, he noted that Consumers’ ongoing Advanced

24 Mr. Pung went on to point out that because the delivery charges addressed in this fifth area of discussion “are set the same” for Consumers’ GPD, GPTU, and MMPP rate classes, the utility “proposes to carry this change through to all three to these rate schedules.” 3 Tr 465. Based on his testimony, it appears that Mr. Pung has no objection to that proposal.
Metering Infrastructure (AMI) program is installing AMI meters across its service territory, “which would allow for the cost-causative element to be priced, thereby sending the appropriate price signal” to each customer. 4 Tr 466. As a result, Mr. Pung testified, the Staff recommends that Consumers be directed to present a plan as part of its next rate case filing regarding “how such a price signal could best be sent to those customers currently not receiving it upon completion of [the] AMI rollout.” Id. The reason that he is not proposing that this change be made immediately, Mr. Pung continued, is because:

In Staff’s opinion, it would be inappropriate to put a rate in place which could only send the appropriate price signal to some customers based, not on a choice made by that customer, but on the Company’s AMI rollout schedule. This could lead to some being able to benefit from changing their demand [during] the system peak while others could not, though not by their own choice.

Id.

Mr. Pung also offered rebuttal testimony, which was limited to one narrow aspect of this proceeding. Specifically, he objected to testimony offered by Hemlock’s witness to the effect that customers who own their substations (and have presumably compensated the utility via facilities agreements for the cost of receiving distribution service) should not be required to also pay part of Consumers’ system-wide distribution expenses. See, 4 Tr 468, citing 3 Tr 359. Among other things, Mr. Pung based his objection on the fact that the Commission has previously addressed this issue in other cases, where it has consistently denied Hemlock’s request. See, Id. For example, he quoted the Commission’s November 4, 2010 order in Case No. U-16191 (November 4 order), where it was held that:
Hemlock made these same arguments in Case No. U-15645. In that case, the Commission found that a separate facilities agreement does not preclude charging the customer for its contribution to recovery of standard distribution facilities costs, unless the agreement contains such language. November 2, 2009 order [in Case No. U-15645], p. 89. The Commission invited Hemlock to introduce the language of the separate facilities agreement showing that a double recovery was occurring in this proceeding. Hemlock has not done so. The Commission finds that Hemlock should continue to pay standard distribution costs. See, also July 1, 2010 order in Case No. U-15981, pp. 53-54. [November 4 order, p. 65.]

4 Tr 469. As a result, Mr. Pung concluded, the Staff recommends that the proposal offered by Hemlock’s witness be rejected. See, 3 Tr 470.

The Staff’s final witness, Mr. Revere, provided rebuttal testimony addressing various rate design-related proposals offered by one of MEC’s witnesses (Mr. Jester), as well as certain statements made by Hemlock’s witness concerning the MEDC Workgroup.

With regard to MEC’s witness, Mr. Revere began by noting that the Staff is not taking a position on the merits of the majority of his proposals. In this regard, he testified that:

As stated in Staff witness Mark J. Pung’s direct testimony, any rate design proposals relying on such data are appropriately left for when AMI meter deployment is complete. Staff’s position on this matter extends to any allocation proposals that rely on these same data. In Staff’s opinion, however, certain of Mr. Jester’s proposals do require contra evidence.

3 Tr 422.

According to Mr. Revere, his first area of dispute with Mr. Jester’s testimony involves the MEC witness’s recommendation that transmission cost allocation for transmission and sub-transmission customers be based on individual contributions to the 12CP demand determinant. In this regard, Mr. Revere expressed his opinion that Mr. Jester failed to justify this proposal. See, 3 Tr 423. According to him, the Staff finds U-17688
the individual allocations that would result from this proposal are not appropriate, largely because they would “impose an unreasonable extra step in the allocation and rate design process,” and would represent “a significant additional administrative burden on the Company and other participants in rate cases,” all while “adding no additional accuracy in matching costs to causation.” Id. As a result, he testified that the Staff recommends that “the proposals on transmission cost allocation and recovery” set forth in its direct testimony “be approved [instead] for the reasons described therein.” Id.

Mr. Revere also addressed Mr. Jester’s proposals regarding distribution rate design. In this regard, he disputed the MEC witness’s claims that wear and tear on the distribution system serves as a major cost causative element, stating that although it is “theoretically possible that some distribution costs are related to increased wear on the system at times of high load,” that portion of Consumers’ expenses (1) was “not identified” in this case, (2) does not likely constitute “the majority of distribution costs,” and (3) is also “likely not reflective of marginal cost” (such as costs incurred to add an additional customer to the system). 3 Tr 425. As for the cost recovery portion of this proposal, Mr. Revere asserted that the Staff “does not agree that a percentage markup like that proposed by the MEC’s witness is the appropriate methodology to use” for the recovery of distribution costs, “as it is not reflective of cost causation.” 3 Tr 426.

The last area of dispute that Mr. Revere had with regard to this MEC witness concerned that witness’s statements to the effect that customers with behind-the-meter generation do not impose costs on the distribution system when using this generation. According to Mr. Revere, those statements were incorrect because, as noted earlier,

25 According to Mr. Revere, customer-related marginal costs would include the cost of the service drop, meter, and additional customer service and billing costs.” Id.
“the major distribution cost-causative elements are those currently utilized” in the allocation process, and not the amount of energy delivered (as Mr. Jeter essentially claims). Moreover, Mr. Revere pointed out that:

A customer with behind-the-meter generation still requires [that] elements of the distribution system be sized to meet their maximum demand on that system, and requires customer-related equipment just like any other customer.

3 Tr 427. As a result, he concluded that MEC witness Jester’s proposal regarding this issue should be rejected. See, Id.

Finally, Mr. Revere offered rebuttal challenging the accuracy of statements made by Hemlock’s witness, Mr. Gorman, “that claim consensus agreements in the [Workgroup Report] represent all participants,” including the Staff. Id. In this regard, Mr. Revere testified as follows:

For example, on page 4 of [Hemlock] witness Gorman’s direct testimony, he states: “the report identifies several consensus agreements among all of the participants in the workgroup, including the MPSC Staff.” Also, on page 5 of [Hemlock] witness Gorman’s direct testimony: “As noted in the report, the consensus of the workgroup, including the Commission Staff, supports the production and transmission capacity allocations as described above [namely, the 4CP 100/0/0 and the 12CP 100/0/0 for production- and transmission-related expenses, respectively].”

Id. [citations omitted]. According to Mr. Revere, although he was one of the Staff members involved in the MEDC Workgroup process that led to the Workgroup Report, he can firmly state that the “consensus agreements” set forth in that document do not include the agreement of the Staff. 3 Tr. 428. Rather, he testified that the Staff “was merely acting in a technical advisory role,” as stated on page 3 of the Workgroup Report, and that none of the positions ultimately advanced by that document “should be read as having Staff approval.” Id.; See also, Exhibit A-14, p. 3.
Based primarily on the testimony of its three witnesses, the Staff makes several recommendations in this case.

First, and foremost (due to the potential magnitude of its effect on the rates to be established as a result of this proceeding), the Staff contends that the Commission should reject Consumers’ proposal to allocate its production-related expenses based on a 4CP 100/0/0 structure. According to the Staff, the utility’s proposal—which allocates all production costs based exclusively on demand—is unreasonable largely both because it is “oversimplified” and because its “does not reflect how costs are usually incurred.” Staff’s reply brief, p. 2. Specifically, the Staff asserts that:

The Company uses different plants to meet demand as the load on its system changes, and these plants have different costs. The Company’s approach, however, does not account for these differences; [rather,) it treats all costs as if they were incurred only to serve peak demand.

Id., citing 2 Tr 127 and 179. This is particularly unreasonable, the Staff continues, in light of the fact that (as noted by Mr. Putnam) Consumers’ cost per kW of capacity is $1,000 for its base load units and only $277 for its other units. Id., p. 3, citing 3 Tr 436. Moreover, the Staff asserts that the adoption of the utility’s production cost allocator strays from both the Governors’ expressed vision for a “no regrets” energy future and Act 169’s instruction to explore different methods of cost allocation and rate design that “support affordable and competitive rates for all customers” due to the fact that it “unduly burdens” residential ratepayers.26 Id., pp. 4 and 5. In place of the production cost allocator proposed by the utility, the Staff advocates in favor of adopting the 4CP

26 The Staff also expresses agreement with assertions made by witnesses for other parties to the effect that, by failing to truly explore any of the many alternative allocation methods discussed in the NARUC Manual, Consumers has not shown that its current 4CP 50/25/25 production cost allocation structure is inferior to the 4CP 100/0/0 method sought in this case. See, Id., pp. 16-18.
75/0/25 method described in Mr. Putnam’s testimony if, indeed, any change is made regarding the allocation of these costs.\(^{27}\) This is, the Staff contends, a much more balanced approach than allocating such costs exclusively on peak demand, and it would avoid the situation where low load-factor customers are improperly subsidizing high load-factor customers. See, Staff’s initial brief, pp. 6-13.

Second, the Staff supports adoption of Consumers’ proposal to allocate its transmission-related expenses through the application of a 12CP 100/0/0 methodology. It reaches this conclusion because that method would allocate transmission costs in the same manner in which they are incurred, which is solely on the basis of demand. See, Id., pp. 13-14.

Third, the Staff recommends that the Commission reject the company’s request to reclassify nearly all of its customer assistance expense to other accounts, thereby fixing a mistake the utility made in the course of its most recent rate case. The Staff’s recommendation arises from the fact that, based on an analysis done by Mr. Putnam, making this change in isolation would unduly harm residential ratepayers. See, Id., pp. 15-16, citing 3 Tr 441. In the alternative, should the Commission be allowed to fix its mistake in the context of this proceeding, the Staff argues that the Commission should offset some of that harm by directing Consumers to make a corresponding change (as suggested by Mr. Putnam) to the assignment of its UAEs. See, Staff’s reply brief, p. 6.

\(^{27}\) As noted elsewhere in this PFD, both the Attorney General and MEC recommend retaining the current 4CP 50/25/25 production cost allocation structure. The Staff agrees that continuing to use that method would be reasonable, should the Commission be so inclined. See, Staff’s initial brief, p. 25.
Fourth, the Staff supports all of the utility’s proposed cost allocation and rate design changes for its GPD rate class, including the company’s requested adjustment to the Power Factor Provision contained in that tariff. See, Id., p. 10. Similarly, it supports Consumers’ request to continue allocating capacity costs to its MMPP customers at approximately the same level as they are currently allocated. See, Id.

Fifth, the Staff opposes several changes sought by MEC with regard to transmission and distribution cost allocation and rate design. These include such things as MEC’s requests to (1) cease allocating distribution costs by voltage level--as Consumers currently does--and, instead, begin allocating them based on the cost of energy, (2) exempt customers with behind-the-meter generation or storage capabilities from distribution charges whenever those facilities can be used to meet their load requirements, and (3) use percentage markup as the means of recovering distribution costs. For reasons expressly set forth in Mr. Revere’s rebuttal testimony, and which have been fully described above, the Staff asserts that none of these proposed changes should be approved. See, Staff’s initial brief, pp. 20-22.

Sixth, the Staff likewise opposes MEC’s repeated requests to initiate dynamic or time-of-use pricing in this case, or to require that Consumers automatically move customers to the least-cost rate available. Relying on testimony offered both by Mr. Revere and Mr. Pung, the Staff contends that it is premature to design rates that way because Consumers has not finished installing smart meters throughout its service territory, thus currently leaving a great many customers with no means of taking advantage of MEC’s pricing proposals. See, Id., pp. 22-23. The Staff therefore recommends that all requests for dynamic or time-of-use rates be denied, at least until
the utility’s AMI deployment is complete. See, Id., pp. 24-25. As for MEC’s suggestion that the utility be required to move customers to the least-cost rate, the Staff points out that:

[A]lthough the Company has data to know what would have been a lower cost rate for the customer in the past, [it] has no way of knowing what the least cost rate will be for any given customer now or in the future. Customers’ usage or times of that usage could change significantly at any point for reasons the Company is unaware of.

Staff’s reply brief, p. 18. For these and other reasons, the Staff contends that the MEC’s proposed changes be rejected.

Seventh and finally, the Staff agrees with Consumers’ recommendation to implement the rates approved in this case as of December 1, 2015, even if the final order of the Commission is issued before that date. In so doing, the Staff accepts the utility’s assertion that using that implementation date makes sense “because that is the date the Rate E-1 subsidy will be eliminated.” Id., p. 10. As a result, the Staff asserts that ABATE’s request to implement rates simultaneously with the issuance of the Commission’s order in this case should be rejected. See, Id., p. 9.

F. Attorney General

The Attorney General presented both direct and rebuttal testimony, along with several related exhibits, from Michael J. McGarry, Sr., the President and Chief Executive Officer of Blue Ridge Consulting Services, Inc.

Mr. McGarry recommended that the Commission reject Consumers’ proposal to allocate production costs on the basis of the 4CP 100/0/0 method, and likewise reject its proposed reallocation of both LIEEF and EO expenses. See, 2 Tr 296 and 314. After reviewing the August 5 order and Consumers’ filing, Mr. McGarry testified to his opinion
that the company’s application does not contain all of the information needed to support the proposed changes, and does not provide an evaluation of the impact of the proposals on all customer classes in terms of affordability or competitiveness. See, 2 Tr 300.

Mr. McGarry went on to note the existence of the MEDC Workgroup, and objected that neither residential nor small commercial customer advocate groups “who normally intervene in rate proceeding before the Commission” were invited to participate. 2 Tr 301. He did, however, list the participating individuals and companies that did participate, and noted—as other witnesses have—that the Workgroup Report was admitted as Exhibit A-14. See, Id. Moreover, Mr. McGarry pointed out that the Workgroup Report “focuses on rates that follow cost causation, with an emphasis on the high load factor customers’ benefit to the system.” Id.

This witness went on to testify that, based on his experience, demand is not the sole determinant of a utility’s decision to acquire new capacity. See, 2 Tr. 303. Rather, he stated that if it were the sole determinant, a utility would construct the lowest-cost peaking capacity it could, and cited the NARUC Manual’s discussion of the Equivalent Peaker Method as support. See, 2 Tr. 306-307. He further testified that Consumers refused to provide a cost-of-service run using this method, as was reflected by Exhibit AG-3, and he used this refusal as a partial explanation regarding why the Attorney General is not recommending use of the Equivalent Peaker Method in this case. He also stated that, at least “in a relative sense,” it is possible to determine whether particular customer classes are increasing their peak load or electric usage. 2 Tr 308. In this regard, Mr. McGarry provided a chart depicting the total 5-year electric delivery
forecasts included by the utility as part of its 12 most recent PSCR plan case filings. See, 2 Tr 308. According to him, this chart shows that “the residential class has had the lowest forecast rate of increase (and, in some forecasts, a decrease) in 11 out of 12 forecasts prepared by the Company.” Id., citing Exhibit AG-4. On the flip side, he pointed out that Consumers’ application did not include either a demand forecast or a load forecast, and forecasts subsequently provided by the utility failed to break down the data by customer class. See, 2 Tr 308-309.

Mr. McGarry next testified that in developing a cost allocation methodology, he would “collectively look to what caused that particular type of equipment to be installed, the present use of the equipment, and the future needs of the utility and its customers” before deciding on a particular method. 2 Tr 309. According to him, this is what Consumers apparently did when making its recent decision regarding the Thetford Generating Unit and its subsequent alternative, which he stated serves to indicate that “production costs were not incurred to solely increase capacity but rather to provide lower costs for customers.” 2 Tr 310. Because “high load factor customers, with their more intensive energy needs, benefit (along with all other customers)” from the utility’s choice in that instance, Mr. McGarry asserts that “a production cost allocation methodology that includes an energy component is appropriate.” Id. In contrast, he continued, Consumers’ proposal to adopt a 100% demand-based production cost allocation methodology essentially ignores the broad spectrum concepts of capacity planning. In this regard, he testified that:

Under a 100% demand allocation, as proposed by the Company, the costs for the recently-purchased combined cycle unit, along with the Company’s extensive hydroelectric resources, [would] not be allocated, even partially, based on energy. Rather, they [would] be based on CP demand, thus
shifting a greater responsibility to low load factor customers, such as the residential and small commercial classes. Since these classes are forecast to have the least growth [at least according to data taken from Exhibit AG-4], the proposed allocation methodology should, but does not, address the forecast customer impacts to these classes.

2 Tr 310.

Based on the above-noted factors, Mr. McGarry asserted that the Consumers’ filing “is incomplete and does not provide a record that all parties can review and explore.”

2 Tr 311. He therefore recommended that the existing production cost allocator, which uses a 4 CP 50/25/25 structure, be retained at this time. See, Id.

Mr. McGarry concluded his direct testimony by expressing concern regarding Consumers’ proposal to remove certain cost components from FERC Account 908 (namely, LIEEF and EO expenses) and have them allocated through other accounts. See, 2 Tr 314. Because other expenses and surcharges, and their potential means of allocation, were not mentioned in the utility’s application, “it is not clear” whether the company’s focus exclusively on an Account 908 cost “is a special case or has been chosen for some specific reason or effect.” 2 Tr 315. As a result, he recommended that

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28 As further support for this assertion, Mr. McGarry testified that Consumers’ proposed residential rate design would increase the top rate for the initial block of electricity purchased during the summer months by 6.4% and that of the second block (for summer purchases over 600 kWh/month) by 4.5%, while also raising the winter rate by 6.4%. See, 2 Tr 311-312. According to him, this is but one example of a change that “does not send a price signal that peak summer demand is important to the Company,” because the “following” summer rate block received a lower increase than either of the other two. 2 Tr 312. This, he continues, “demonstrates another element of the Company’s Application that is incomplete and, possibly, not thought through.” 2 Tr 313.

29 Although Mr. McGarry refers to Consumers’ current production cost allocation methodology as being a 12CP-based structure, this appears to be a mistake arising—at least in part—from the fact that the order adopting the settlement in Case No. U-17087 did not specifically discuss the matter of coincident peaks. Nevertheless, testimony provided by other witnesses in the this proceeding expressing the understanding that the utility is currently employing a 4CP-based allocation method with regard to production costs, as well as the fact that the Commission’s last direct ruling on this matter clearly adopted a 4CP-based methodology, makes it clear that the existing methodology for allocating Consumers’ production-related costs is the 4CP 50/25/25 structure. See, i.e., 2 Tr 143, 2 Tr 257, 3 Tr 435, and the Commission’s June 7, 2012 order in Case No. U-16794, at p. 107.
no change be authorized with regard to the allocation of Other O&M expenses contained in FERC Account 908.

Through his rebuttal testimony, Mr. McGarry expressed concern regarding various statements made by witnesses for the Staff, ABATE, Hemlock, and Energy Michigan. This testimony falls into four discrete areas.

First, Mr. McGarry addressed Staff’s testimony, and in particular Mr. Putnam’s analysis of Consumers’ load data in developing the Staff’s production cost allocation proposal. Mr. McGarry characterized Staff’s approach as “a very rudimentary version of the Equivalent Peaker Methodology” discussed in his direct testimony. 2 Tr 325.

Focusing on the Staff’s conclusion that base load energy constituted 62% of the utility’s total energy generated for the year, which was arrived at by dividing the average energy per hour by the minimum-hour load for the year, Mr. McGarry testified that it is “unclear to me what the significance this ratio (minimum to average) has in comparison to the generation and other factors of base load plants.” Id. He ultimately concluded that:

Staff’s analysis demonstrates an awareness that the cost of base load generation is a very significant portion of total generation assets (72.9%) and that there are capacity planning dimensions in determining an appropriate production cost allocation methodology. However, Staff’s methodology is subject to significant concerns about definitions, the rounding of down of its calculated energy component, the underestimation of needed base load capacity, the use of a single year to derive its recommendations, and the dated nature of that year compared to the rate year that customers might see the proposed revenue shift.

2 Tr 327. As a result, Mr. McGarry recommended that the Staff’s position be rejected, subject to the Commission directing Consumers to provide the parties with a range of cost allocation methodologies, “including Equivalent Peaker Methods, to ensure that all relevant cost allocation methods can be explored” in the context of its on-going rate
case, namely Case No. U-17735. 2 Tr 328. According to him, this is necessary in order to more fully provide a record for the Commission “in a proceeding that [unlike this Act 169 case] is not subject to the Legislature’s fast track provisions.” 2 Tr 322.

Mr. McGarry’s rebuttal testimony next focused upon statements made by witnesses for ABATE and Hemlock, which he viewed as requests to “change” from a 12CP-based allocator for production costs to a 4CP-based structure.\(^{30}\) See, 2 Tr 330. According to Mr. McGarry, his direct testimony indicating the reasons why the Commission should reject Consumers’ identical proposal justifies disregarding both ABATE’s and Hemlock’s positions regarding their sought-after change to a 4CP 100/0/0 production cost allocation methodology. See, Id.

Turning to Hemlock witness Gorman’s requests to establish a high load factor sub-class within Rate GPD, and to revise Consumers’ existing owned substation credit, Mr. McGarry “takes no position” on the respective merits of those issues. Id. However, because he views those proposals as having “forward-looking implications,” he testified that “these two issues would be more appropriately addressed in [Consumers’ ongoing] base rate case. Id.

The final area addressed in Mr. McGarry’s rebuttal testimony concerns two of the proposals offered by Energy Michigan’s witness, Mr. Zakem. The first of these was the proposal to essentially reallocate UNEs “as a Company Wide Overhead,” while the second was the suggestion that UNE’s be separated “by Distribution and Power Supply.” 2 Tr 331. While “both of these issues have merit and are worthy of review,” Mr. McGarry testified, “they are both forward-looking (like Hemlock’s proposed changes

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\(^{30}\) As previously discussed in footnote 29, supra, allocating production-related costs on a 4CP basis is not a change from what is currently in place for Consumers.
to Rate GPD) and not within the scope” of this Act 169 proceeding.  Id.  Thus, he concluded his rebuttal by recommending that the Commission reject Mr. Zakem’s proposals and “suggest that the issue [also] be addressed by the parties in the Company’s base rate filing in [Case No.] U-17735.  Id.

Despite its active participation in this case through the end of the evidentiary proceeding, however, the Attorney General did not offer formal written arguments by way of post-hearing briefs.

G.  MEC

The MEC offered testimony and exhibits from two witnesses. The first of these was Douglas B. Jester, a Principal with 5 Lakes Energy, LLC, who offered both direct and rebuttal testimony, and a total of 15 exhibits. The second MEC witness was George E. Sansoucy, a Registered Professional Engineer and utility consultant, who offered direct testimony and 11 related exhibits.

Mr. Jester began his direct testimony by recommending that the Commission reject Consumers’ proposed cost allocation and rate design changes because, in his opinion, they fail to meet the standards set forth in Act 169.  See, 3 Tr 487-488. Specifically, he disputed that Consumers’ proposal will better ensure that rates equal the cost of service, taking issue with its claim that customers with higher load factors are less expensive to serve, and contending that low-load-factor customers that consume power during low-load periods are actually less expensive to serve than customers with higher load factors.  See, Id. He also testified that, in his opinion, Consumers failed to address whether its proposed change in cost allocation would provide affordable and competitive electric rates for all customer classes, as mandated by Act 169.
Mr. Jester further testified that Consumers’ proposal “merely shifts (i.e., reallocates) costs without any effort to reduce them.” 3 Tr 489. Along these lines, he presented Exhibits MEC-2 and MEC-5 to show that, in comparison to other states, Consumers’ rates are neither competitive nor affordable, and further noted that Consumers has recently filed a general electric rate case that, among other things, “proposes that residential rates increase by 10.5% in 2015-16 and an additional 4.3% over the 2015-16 rates in 2017.” 3 Tr 494. Mr. Jester also took issue with what he perceived as Consumers’ limited consideration of cost allocation alternatives, testifying that the utility did not explore important allocation methods contained in the NARUC Manual. In his opinion, the company only explored alternatives as part of the MEDC Workgroup, which focused on ways to reduce rates for large industrial customers as a potential means of economic development. According to Mr. Jester, “it isn’t reasonable to accept that the company’s participation in that Workgroup fulfills the Legislature’s intent” as expressed in Act 169. 3 Tr 499. Specifically, he continued:

[A]nalyzing and reporting impacts to all ratepayers of methods of cost allocation and rate design that were selected for consideration because they might lower rates for energy-intensive industrial customers is not the same as “exploring different methods for allocation of . . . costs and overall rate design, based on cost of service, that support affordable and competitive electric rates for all customer classes.” Nor does participation in a workgroup made up predominantly by representatives of energy-intensive industrial customers represent a sufficient process for identifying different methods of cost allocation and overall rate design that warrant exploration.  

Id. Nevertheless, he noted, Consumers indeed followed the various recommendations regarding cost allocation spelled out in the Workgroup Report. See, 3 Tr 500.

Turning specifically to Consumers’ proposed 4CP 100/0/0 production cost allocation methodology, Mr. Jester testified that his analysis shows that not all capacity
costs are caused by peak loads and, as a result, using the 100% 4CP method is not valid. Along these lines, he testified that simply trying to reduce rates for high load factor customers does not justify changing the current 50-25-25 method, which already accounts for varying load factors. See, 3 Tr 487. Moreover, Mr. Jester testified that Consumers should have considered other allocation methodologies, including marginal cost methods, as well as cost-causation methods of embedded cost allocation discussed in the NARUC Manual. See, 495-498.

Mr. Jester also took issue with what he characterized as Consumers' failure to adequately consider rate design in this case, testifying that a substantial body of research demonstrates dynamic pricing and time-of-use methods produce superior cost allocations. See, 3 Tr 497. According to him, the utility should have given more consideration to the capabilities of its advanced metering installations, and should have also considered adopting billing determinants that reflect the factors driving the cost of service. See, 3 Tr 501-503.

He also recommended that rates reflect marginal cost pricing, at least “to the extent practicable.” 3 Tr 506. In explaining marginal cost pricing conceptually, he testified that by charging uniform rates per kWh for energy at all times, energy charges will generally be greater than the cost of producing one more unit, but at peak times, will be less than the cost of producing one more unit, and thus prices will not reflect marginal cost at any time. He then pointed out that the consequences of using incorrect price signals include subsidization of those customers whose consumption occurs disproportionally at peak times, as well as general economic inefficiency as customers who spend greater portions of their income on energy reduce their consumption of other
goods and services, or otherwise respond to the incorrect price signals. See, 3 Tr 501-505.

Mr. Jester also testified that strict marginal cost pricing would not supply Consumers with its full revenue requirement because certain shared and joint costs are not susceptible to marginal cost pricing, and because utilities cannot have perfectly optimal generation portfolios. See, 3 Tr 505. In this context, Mr. Jester discussed Ramsey-Boiteux pricing, an economic theory regarding the setting of prices in a monopoly market to minimize the adverse consequences of prices above marginal cost that allocates the additional revenue to be recovered in inverse proportion to the price-elasticity of the customers. He stated that this model supports his recommendation that Consumers’ revenue requirements above the revenue that would be received from marginal cost pricing be charged as a uniform percentage markup above the marginal cost of energy, his recommendation that low-income customers not be assigned certain joint and shared distribution costs, and his recommendation that the transmission and distribution costs be allocated by voltage level to limit the exposure of energy-intensive customers to joint and shared primary and secondary distribution network costs. See, 3 Tr 507-511.

Mr. Jester went on to note that pricing reforms of the nature that he recommends will reduce the need to make future investments in capacity, as well as reduce line losses and distribution system maintenance costs, because customers will respond to proper pricing signals by being more efficient or shifting usage. See, 3 Tr 510-516. He further recommended that the Commission adopt dynamic or time-of-use rates for all customers, emphasizing lower everyday rates with higher rates at peak times, and
establishing a transition period for each customer class. See, 3 Tr 517-519. He then presented a paper (received into evidence as Exhibit MEC-6) to support his claim that low-income customers do, indeed, reduce their peak consumption in response to higher peak prices. See, 3 Tr. 514-520. Similarly, he presented Exhibits MEC-9 and MEC-10 in support of his recommendation to expand Consumers’ dynamic pricing pilot program, by showing the degree to which the program has previously reduced energy usage. From the information in these reports, as well as MISO’s estimate of the cost of new energy (CONE) as provided in Exhibit MEC-12, he estimated a 719 MW reduction in Consumers’ load requirements from implementation of a residential dynamic peak pricing requirement--equivalent to a savings of $65 million per year--and extrapolated that to a savings of $100 million a year when commercial and industrial customers are included. See, 3 Tr 529-533.

Mr. Jester testified that the impacts of his recommendations depend on many details of the Commission’s ultimate decision in this case, although he expects that applying dynamic and time-of-use rates as he proposes will reduce Consumers’ revenue from industrial customers, slightly increase its revenue from commercial customers, and also increase its revenues from residential customers relative to existing rates, with the “revenue totals by class” ending up “similar to those [described] in Consumers’ proposal.” 3 Tr 512. In the short term, he testified, the average customer bill will be unchanged, but he expects that even customers who ignore the time-variation of rates are likely to benefit eventually, either from reduced overall rates or an improvement in energy-consuming products and services. See, 3 Tr 516.
In explaining how capacity charges would be recovered under his dynamic pricing proposal, Mr. Jester further addressed Consumers’ proposal to recover capacity charges from primary, sub-transmission, and transmission customers through a demand charge, asserting instead that these customers should pay their allocated share of capacity costs through peak period charges on their power consumption during announced peak load periods. See, 3 Tr 526-527. He further testified that Consumers’ residential dynamic pricing rate limited peak pricing to 8 events per year on high-load weekdays, but recommended instead that peak pricing take effect whenever load exceeds a given threshold to be set by the Commission, with the intent to reduce load to that threshold. See, 3 Tr. 533-534. He then gave an example calculation to show how that threshold could be set, taking into account the utility’s current capacity, planned retirements, and reserve margin requirements. See, 3 Tr 534-539.

Mr. Jester next testified that the costs that should be allocated using peak pricing should be the marginal cost of capacity at this threshold, and he provided an example calculation using an estimated peak load threshold of 6,550 MW, with a MISO reserve margin requirement of 505 MW, and the same CONE value of $90.53/kW provided in Exhibit MEC-11 to calculate that $638.7 million should be recovered through the peak pricing charges, leaving the remainder of Consumers’ total production costs (approximately $2.2 billion) to be recovered through energy charges. See, 3 Tr 546. Mr. Jester also analyzed Consumers’ production costs relative to the revenue it would have received at locational marginal prices (LMP) during 2013, as calculated in his Exhibit MEC-13, contending that a measure of the deviation of the utility’s generation portfolio from an optimum portfolio can be calculated as the difference between the
LMP-based revenue calculation and the approximately $2.2 billion that he calculated should be recovered from an energy charge. See, 3 Tr 547.

For those production costs that are to be recovered through an energy charge, Mr. Jester identified options for allocating those costs using methods identified in the NARUC Manual, including the Equivalent Peaker Method, the Production Stacking Method, or the Probability of Dispatch Method, with rates designed as uniform charges or time-of-day charges, as well his preferred proposal to use a multiple of an LMP. See, 3 Tr 550-551. However, in case the Commission rejects his proposals for dynamic pricing, he also recommended that it rely on one of the same alternate methods of cost allocation in the NARUC Manual that includes an energy component, using the same reasoning leading to his recommendation to use dynamic pricing based on energy consumed during peak periods. 3 Tr 534-535. Mr. Jester also explained how integrated resource planning principles support the use of these alternate methods. 3 Tr 540-547.

Mr. Jester went on to testify that he supports moving to voltage-level rates for distribution charges, and he accepts Consumers’ proposed allocation of transmission and distribution costs, with additional recommendations as to how rates should be set to recover those charges. See, 3 Tr 553-556. For transmission and sub-transmission customers, Mr. Jester recommended that those customers be charged for transmission based on their individual contribution to the prior year’s 12 monthly coincident peaks, while for primary and secondary customers, he recommended that transmission costs be pooled with distribution costs. See, 3 Tr 556-559. For primary and secondary voltage customers, he testified that allocating distribution costs within each voltage level
as a percentage of the cost of energy delivered is better than allocating those costs based on power consumed, which includes on-site generation. He asserts that on-site generation does not impose costs or receive benefits from the distribution system. See, 3 Tr 559-564. He further recommended no distinction between residential and commercial customers.

Mr. Jester next offered several recommendations with regard to behind-the-meter generation and storage, which he stressed should apply regardless of whether the customer has a single meter or is separately metered for consumption and distribution. According to him, these recommendations should also apply to any customer with either behind-the-meter generation energy storage. 3 Tr 566. He went on to state that “his most important recommendation is that unless a customer participates in net metering and is subject to those particular rules:

(1) All power delivered to such a customer should be charged to the customer at the applicable power and delivery charges.
(2) All generation or storage discharge that is instantly consumed on-site should be considered as self-service and not subject to charges by [Consumers].
(3) Any generation or storage discharge that exceeds instantaneous on-site consumption and is delivered to the transmission or distribution grid should be credited at the applicable power rate, including both energy and peak power prices, and for the avoided line-loss rate, but not credited for delivery charges.

3 Tr 567. According to Mr. Jester, these rules directly reflect the concept of cost causation addressed in this case, and should thus be addressed in this proceeding. See, Id. Mr. Jester further stated that it is of particular importance that “all customers with behind-the-meter generation” be allowed access to any available dynamic rate tariff ultimately adopted by Consumers, regardless of whether they are taking service under net metering or any other tariff. Id.
Mr. Jester went on to assert that his recommendations regarding the establishment of dynamic or time-of-use rates will, however, require an adjustment to rates for cogeneration under the federal Public Utility Regulatory Policies Act (PURPA), as well as other behind-the-meter generators. Specifically, he stated that:

Part of the rationale for stand-by rates has been that costs of capacity have been embedded in energy rates, so that customer generation didn't have the appropriate incentives to generate at peak load times, discounting their capacity value. Given my recommendations concerning use of dynamic peak pricing, that will not be the case. Any generator foregoing generation during peak pricing periods will be foregoing substantial revenue. Any generator foregoing generation outside peak pricing periods will not be causing [Consumers] to incur capacity requirements as such load can be served with capacity that [Consumers] controls for the purpose of satisfying peak load requirements.

3 Tr 568. Moreover, Mr. Jester stated, although the utility's planning reserve margins are based on “the summed effects of uncertainty in customer demand and the probability of forced generator outages,” entities with behind-the-meter generation do not contribute in any specific way to uncertainty regarding customer demand forecasts. Id. As argued earlier, he continued, “the long-run marginal cost of capacity is just the [CONE] of a capacity resource.” Id. Therefore, Mr. Jester concluded, standby charges should be revised to reflect the product of the CONE and the technology-specific forced outage rate of the behind-the-meter generator.

He also noted that the dynamic rate tariff could be considered the basis for the avoided cost payments to generators made under PURPA. Specifically, Mr. Jester testified that two of the methods used by the states to establish the avoided cost are (1) the proxy resource method, and (2) the partial displacement differential revenue requirement method. See, 3 Tr 569. Moreover, he continued, the use of a dynamic rate tariff as a means of establishing avoided cost would be consistent with both of those
methods, and would also have the advantage of keeping Consumers revenue neutral while sending appropriate price signals regarding when to produce power. See, Id. As a result, Mr. Jester asserts that compensation due to such producers under Consumers’ standard tariff should be based on the dynamic tariff rate. See, 3 Tr 569-570.

The final area addressed by Mr. Jester in his direct testimony concerned a host of proposed changes or additions to Consumers’ specific rate schedules. Among the more significant of these are requests to have the utility do the following:

- recover production capacity costs through peak load charges, and generation costs through energy charges;
- charge peak load prices to its customers whenever it is called upon to deliver load exceeding a specific Commission-established threshold, which would initially be set at 6,300 MW;
- set the revenue recovery through peak load pricing equal to the product of the current CONE and the sum of a current Commission-approved load threshold and the planning margin reserve;
- recover transmission costs based on the determinants of those costs, charge them to transmission and sub-transmission customers based on their 12-month trailing contributions to CP12, and allocate them to Consumers’ distribution customer classed based on their contribution to the utility’s CP12 transmission determinants;
- recover distribution costs for power delivered to the primary distribution system by allocating those costs to the primary distribution system and pooling them with costs incurred for the primary system;
- establish a new Eligible Low-Income Household (ELIH) rate schedule, with numerous provisions regarding eligibility requirements and a separate level of line-loss costs;
- establish a Dynamic Rate Schedule for each voltage level at which it serves customers;
- establish a Time-of-Use (TOU) Rate Schedule for its Secondary Distribution customers;
- set the non-peak energy charges for Dynamic Rate Schedule customers as a fixed multiple of the day-ahead location marginal price;
- adopt the time-interval pricing structure from the Residential Dynamic Pricing Pilot for non-peak charges to TOU customers; and
- close the following: Rate Schedule RT, Rate Schedule GS, Rate Schedule GSD, Rate Schedule GP, the MMPP rate, Rate GSG-2, Rate GML, and Rate GUL.
See, 3 Tr 570-587. In addition, Mr. Jester recommended that Consumers be required to assign each customer to the most favorable rate schedule for that customer, giving the customer the opportunity to opt out rather than opt in. He presented Exhibit MEC-8 to support his recommendation. See, 3 Tr 522-524.

In his rebuttal testimony, Mr. Jester began by addressing Staff’s analysis of Consumers’ proposed 4CP 100/0/0 production cost allocation methodology, agreeing with Staff witness Putnam that production assets provide both energy and capacity, that energy should thus be included as a component of a production allocator, and that base load resources are more expensive than resources used to meet demand peaks. He further agreed with Mr. Putnam that incurring the higher cost of base load capacity versus peaking capacity “is only justified by the reduced variable cost of generation over many hours of the year,” thus showing that “the cost of base load capacity must be partially considered as a cost of energy generation and allocated on that basis.” 3 Tr 590. He opposed adopting the Staff’s proposed 4CP 75-25 production cost allocation methodology, however. In so doing, Mr. Jester testified that:

I find that [Mr. Putnam’s] calculation that base load units constitute 72.9% of the total cost of all [Consumers] generating units in the test year to be approximately correct. However, utilities do not build base load plants only to serve the minimum load that occurs during the year.

3 Tr 591. In this regard, he presented a load duration curve as part of his rebuttal to corroborate his testimony to the effect that appropriate integrated resource planning will generally require greater base load generation capacity than the minimum annual generation. See, Id. He further testified that Consumers’ base load capacity far exceeds the minimum load for 2013, as shown in Exhibit S-4. Mr. Jester further testified that, unless Consumers and the Commission believed that this capacity was needed for...
energy production, it would have been cheaper to build peaking capacity. See, 3 Tr 593. He also testified that:

In his Exhibit S-3, Mr. Putnam reports that the average cost per kW capacity for plants in his “Other” category is $277, in contrast to plants he classifies as base load that have an average cost of $1,000 per kW capacity. Thus, at least $623 per kW of the cost of base load capacity should be considered as incurred to enable cheaper energy production. This suggests that about 62.3% of the cost of base load capacity [on Consumers’ system] is to meet energy generation, which would correspond to 45.4% (72.9% x 62.3%) of production asset costs being allocable to energy. This result is more consistent with the statutory default allocation of production capacity costs, 50-25-25, than with the 75-0-25 allocation proposed by MPSC Staff.

Id.

The next area addressed in Mr. Jester’s rebuttal concerned Staff witness Pung’s testimony recommending that the Commission wait to adopt rate designs based on the use of advanced metering until all customers have received smart meters. Mr. Jester testified that, in his opinion, there is no reason to wait; Consumers will have installed smart meters “to about 40% of its electric customers by the end of 2015.” 3 Tr 594. Moreover, he asserted that a phased deployment of his proposed dynamic rates can be done in such a way as to correspond to the utility’s roll-out of its AMI infrastructure. 3 Tr 595. In addition, Mr. Jester asserted that “even the permanent lack of universal deployment of interval metering or AMI does not undermine the benefits of providing dynamic rates,” as noted in Part 5 of a paper by Joskov and Tirole that was received into evidence as Exhibit MEC-26. 3 Tr 597.

Mr. Jester concludes his rebuttal testimony by responding to a statement made by ABATE witness Selecky to the effect that adoption of a 100% demand-based allocator for production-related fixed costs is the only way to implement Governor
Snyder’s recently-announced energy policy. According to Mr. Jester, such a claim is wrong for five reasons.

First, Mr. Jester notes that despite respecting the Governor’s policy goals, “the sole standard for the Commission to consider” in the context of this Act 169 proceeding is to “better ensure rates are equal to cost of service” and to design rates “that support affordable and competitive electric rates for all customer classes.” 3 Tr 598.

Second, he pointed out that reducing electric rates for energy-intensive industrial customers is not the only announced goal of Governor Snyder’s energy policy. According to Mr. Jester, even the Workgroup Report referenced by Mr. Selecky contained the Governor’s stated goal that “Residential customers should spend less on their combined energy bills (electric and heat) than national averages.” Id. As pointed out in his direct testimony, Mr. Jester continued, because the 100% demand allocator for production-related fixed costs serves to increase residential energy bills, it undermines that goal. See, Id.

Third, Mr. Jester testified that:

[A] 100% demand allocator for production-related fixed costs fails to expressly advance Governor Snyder’s goal to “[e]nsure energy-intensive industries can choose Michigan for job and investment decisions, to better compete.” Mr. Selecky offers no evidence that it will achieve this result. I show in my direct testimony that [Consumers’] proposal, which includes use of a 100% demand allocator for production-related fixed costs, fails to materially change the relative ranking of Michigan's industrial electricity rates. Thus, if energy-intensive industries cannot choose Michigan for job and investment decisions (which is a claim neither made nor supported by the testimony of Mr. Selecky or any other party to this case), there has been no demonstration that a 100% demand allocator for production-related fixed costs will in fact implement even this one goal of Governor Snyder’s energy policy, let alone his complete list of goals.

3 Tr 599.
Fourth, Mr. Jester asserted that there are other changes in rate design that will help “[e]nsure energy-intensive industries can choose Michigan for job and investment decisions, to better compete.” Id. Specifically, he continued, the substance of his direct testimony was to show how implementing dynamic rates for all customers (and especially the use of dynamic peak pricing) would “benefit both energy-intensive industrial customers and all other customers by reducing [Consumers’] costs of service.” Id. According to him, dynamic rates can be used to advance all of the Governor’s announced energy-related goals, which—as reflected in Exhibit MEC-25—is a view shared by many of the energy-intensive industrial customers who are members of ABATE. See, Id.

Fifth and finally, Mr. Jester concluded his rebuttal testimony on this issue by stating as follows:

Mr. Selecky attempts to suggest in his testimony that any allocation of fixed production costs on an energy basis is “judgmental.” However, he does not, and cannot, make a case that the 100% demand allocator for production-related fixed costs is anything but a judgment regarding cost causation. The [MEDC] Workgroup meeting minutes I am sponsoring as Exhibit MEC-25 document that the objective of the [MEDC] Workgroup was to lower industrial rates as much as possible. Not surprisingly, therefore, the [MEDC] Workgroup selected the 100% demand allocator for production-related fixed costs, which resulted in the largest decrease to industrial rates of any allocation method evaluated in those meetings. Further, Mr. Selecky does not, and cannot, make a case that other methods of cost allocation that allocate some production plant costs to energy—including methods identified in the [NARUC Manual] provided as Exhibit MEC-17 in this case and the dynamic rate design that I proposed—are more judgmental, since they are derived from formal analyses of costs and causation using the very methods by which utilities undertake costs.

3 Tr 599-600.

MEC’s second witness was Mr. Sancoucy, whose direct testimony focused almost exclusively on Consumers’ proposal to shift its allocation of production-related costs
costs from the 4CP 50/25/25 methodology to the 4CP 100/0/0 method. See, 3 Tr 605. According to him, that proposal is the largest single driver of the shift in costs from industrial customers to residential customers included in Consumers’ application. See, 3 Tr 607. Specifically, he continues, Exhibit A-12 reflects that granting the utility's request on this single issue would increase residential customers’ share of production-related costs by $46 million while reducing those allocated to industrial customers by $50 million. See, Id. Similarly, he points out that testimony provided by Consumers’ witness Ross as part of the company’s filing in Case No. U-17735 (the utility’s ongoing general electric rate case) indicates that “the incremental impact of this shift alone is a $55 million increase to residential customers, and a $62 million decrease to primary customers.” Id.

Mr. Sansoucy went on to testify that, according to a discovery response received from Consumers and admitted into evidence as Exhibit MEC-14, the utility only considered one other method of production-related cost allocation in addition to the 4CP 100/0/0 method it proposes in this case, namely a 4CP 75/0/25 structure like that currently supported by the Staff. See, Id. He testified that the utility’s above-mentioned discovery response also acknowledges that the company’s choice of allocation methodologies to consider was based exclusively on the two selected for review by the MEDC Workgroup. See, Id. Following admission of the Workgroup Report (Exhibit A-14), Mr. Sansoucy offered additional information regarding the activities of the workgroup in the form of Exhibit MEC-15.
Mr. Sansoucy further testified that the NARUC Manual that Mr. Ross and others relied upon in this case, namely Exhibit MEC-17, identifies many other allocation methods that Consumers did not investigate. In this regard, he testified that:

The NARUC Manual discusses two categories of cost allocation methods: embedded cost methods and marginal cost methods. Consumers’ proposal, and the other method that Consumers explored, are [both] embedded cost methods. The NARUC Manual lists thirteen embedded cost methods, the vast majority of which Consumers never explored. The only methods that Consumers did explore are categorized in the NARUC Manual as peak demand methods.

3 Tr 608. Nevertheless, he noted, the utility’s witnesses failed to “offer any analytical basis” in support of the company’s decision to review only peak demand methods. See, Id. Rather, he pointed out, Mr. Stubleski “simply states that these were the methods discussed by the [MEDC] Workgroup,” while Mr. Ross merely states that “customer demand requirements are set in the summer months, and therefore fixed capacity costs should be allocated based on each classes’ contribution to summer peak.” Id. Moreover, Mr. Sanscoucy continued, the Workgroup Report itself does nothing more than offer “self-regarding statements about the benefit to the system resulting from the [MEDC] Workgroup participants’ high load factors.” 3 Tr 608-609.

With regard to this last point, Mr. Sanscoucy asserted that high load factor customers do not benefit a utility’s system to the degree necessary to justify the massive cost shift proposed by Consumers in this case. See, 3 Tr 609. Specifically, he testified that substantial capacity is required to maintain system voltage support, and that system voltage support is heavily impacted by large users, citing Exhibits MEC-18, MEC-19 and MEC-20. He further noted that there are very few high load factor customers, and that when they fail or downsize, they leave large pieces of the utility's
transmission system stranded, to be maintained by others. See, 3 Tr 609. He then presented Exhibit MEC-23 to show the historical volatility in Consumers' load, while pointing out that the utility's residential customers have been stable in their energy use during that period, while industrial and commercial customers have shown volatility and decline.

Mr. Sansoucy also expressed his opinion that Consumers should have explored methods of production-related cost allocation that include an energy weighting in order to more accurately capture the complexity of cost causation. See, 3 Tr 610. Specifically, he reviewed two of the other methodologies cited in the NARUC Manual, namely the Equivalent Peaker Method and the Production Stacking Model, testifying that these methods recognize the reality that different types of generating plants have different costs associated with them, and also “serve different purposes within a utility's fleet.” 3 Tr 612. He also reviewed information regarding the cost of peak capacity in comparison to base load capacity, summarized in Exhibit MEC-23, and testified that peaking resources are considerably less expensive than the cost of Consumers' existing base load generation. See, 3 Tr 613. He also presented in Exhibit MEC-24 a comparison of monthly base load versus peak capacity for 2011 and 2013, based on FERC Form 1 filings, to show that “demand is provided for through base load capacity for most of the year,” and that “only during the months when the peak demands exceed base load production capacity” are Consumers' intermediate and peaking plants used. 3 Tr 614.

Based on the foregoing information, Mr. Sansoucy essentially characterized Consumers’ application in this case as a proposal to “allocate 45% of the fixed cost of
its entire production fleet based 100% upon residential customer demand for a few hours on summer evenings,” which—in itself—is electric demand that the utility “plans to meet with [its less-expensive] peaking resources.” 3 Tr 615. Although acknowledging that “residential customers should bear an equitable share of the cost associated with those resources,” he asserted that it is inconsistent with cost causation principles to “allocate the cost of base load resources to residential customers on the same percentage as the peaking resources used to meet peak demand.” 3 Tr 615.

Mr. Sansoucy concluded by testifying that, although the existing 4CP 50/25/25 production cost allocation method is not perfectly consistent with his analysis, it is “far better than what Consumers and the MEDC Workgroup are proposing.” 3 Tr 615. This is because, he continued, “the 50/25/25 method incorporates some energy weighting,” while the methodology touted by the utility and the MEDC Workgroup “incorporates no energy weighting at all.” Id. Mr. Sansoucy therefore recommended that the Commission deny Consumers’ request to shift production cost allocation to the 4CP 100/0/0 methodology.

Consistent with the testimony offered by Messrs. Jester and Sansoucy, MEC begins by arguing that the Commission must reject Consumers’ request to shift to a 4CP 100/0/0 production cost allocation methodology, and instead require the utility to continue allocating at least 50% of those costs on the basis of energy usage. See, MEC’s initial brief, p. 5. Specifically, MEC asserts, the utility’s proposal “does not better ensure that rates are equal to the cost of service, as required by Act 169,” nor does it “support affordable and competitive electric rates for all customer classes,” as also mandated by that statute. See, Id. Instead, MEC continues:
Consumers’ proposal merely shifts massive amounts of cost from primary customers onto residential customers, with no effort to reduce costs overall. A comparison of Consumers’ rates to those of utilities in other states shows that [Consumers’] rates are neither affordable nor competitive. Nor has Consumers justified such a large shift in costs from industrial customers to residential customers.

As support for its proposal, Consumers cites the report of a closed workgroup convened by the [MEDC] and comprised of industrial customers. However, the Workgroup Report reflects nothing more than the most self-interested allocation scheme that [it] could come up with. An objective assessment shows that the most costly portion of Consumers’ production capacity is base load generation – which exists primarily to produce large amounts of energy at relatively low variable costs. Investing high fixed costs to produce energy at relatively low variable cost benefits high-volume energy users such as industrial customers – it is not something a utility does to meet short-interval demand peaks. Therefore, any fair and reasonable cost allocation must include an energy component that corresponds to a substantial portion of the fixed cost of base load resources. Because Consumers’ proposal does not include an energy component, that proposal must be rejected.

Id. With regard to this issue, MEC further asserts–among other things–that (1) the utility failed to explore a reasonable range of alternative allocation structures, (2) the company’s proposal does not better ensure that its rates are equal to the cost of service, and (3) nothing has been presented in this case to show that making Consumers’ requested change will support affordable and competitive rates for all of its customer classes. See, Id., pp. 6-25; See also, MEC’s reply brief, pp. 3-10, 14-16, and 17-21.

MEC next asserts that, in light of testimony offered in this case, the Commission should direct the utility to use dynamic pricing/time-based rates to allocate production-related expenses. See, MEC’s initial brief, p. 25. This could be done, MEC contends, by (1) charging a dynamic peak price to all customers whenever total system load would otherwise exceed a defined peak threshold to be established by the Commission, (2) setting that rate at the level necessary to “recover the costs of Consumers’ dynamic
peak pricing load, plus reserve margin, at the current CONE for advanced combustion turbines," and (3) allocating the remaining production cost revenue requirement to customers using an energy component. Id., pp. 25-26. In support of this proposal, MEC contends, time-based rates like those described through Mr. Jester's testimony meet the requirements of Act 169 better than any other proposal made in this proceeding. See, Id., p. 28.

Finally, for the reasons advanced by Mr. Jester, MEC contends that three of its rate design proposals should immediately be approved by the Commission. The first of these would be to “base delivery charges on voltage levels instead of customer identity,” which MEC asserts “would eliminate the distinction between secondary commercial and residential customers in assigning distribution costs.” Id., p. 40. The second would be to require Consumers to assign customers to the lowest cost rate schedule for which they are eligible, based on the grounds that “public policy should assume that the least costly tariff is what a utility customer prefers unless the customer explicitly chooses otherwise.” Id., p. 41. The third would be to direct the utility to implement the ELIH rate schedule described by Mr. Jester, including its various provisions concerning eligibility requirements and a separate level of line-loss costs, because implementing such a rate at this time will reduce the substantial rate increase for low-income customers that will likely result from this proceeding. See, Id., at 42.
IV.

DISCUSSION AND RECOMMENDATIONS

Based on the above-described history of proceedings, discussion of the regulatory and statutory background against which this case is set, and detailed description of both the evidence presented and the respective positions/arguments of the parties regarding the issues raised in this matter, the ALJ will now attempt to provide a succinct discussion of the pertinent issues and his recommendations regarding their resolution. At this point, it appears that seven general areas of dispute need to be addressed, albeit some with multiple subparts. These consist of: (1) how Consumers’ production-related expenses are best allocated to its customers; (2) the best means of allocating the utility’s transmission costs; (3) how distribution costs should be assigned to the company’s various customers; (4) the best means of allocating and collecting Consumers’ customer-related expenses; (5) what changes to the utility’s rate design should be made at this time; (6) how to best handle several miscellaneous requests made by the parties; and (7) what date should be chosen for the implementation of any rate changes arising from the Commission’s final order in this proceeding. Each of these matters will be addressed seriatim.

A. Allocation of Production-Related Expenses

Far and away, the most important issue to be addressed in this proceeding is how Consumers’ production-related expenses should be allocated to its various customer classes. By way of its initial filing in this proceeding, the utility requested that the Commission authorize it to change from its current 4CP 50/25/25 allocation method
to a 4CP 100/0/0 structure, thereby assigning all of these costs to its various customer classes based exclusively on the basis of peak demand. As discussed above, both ABATE and Hemlock support the company’s proposal, largely on the grounds that it precisely parallels the recommendation made by the MEDC Workgroup and set forth in the Workgroup Report regarding how to allocate production costs.

In contrast, the Staff asserts that, because both history and regulatory theory overwhelmingly support the inclusion of some degree of energy-based allocation regarding production costs, a more appropriate method would be something along the lines of a 4CP 75/0/25 structure.

For their part, witnesses for both the MEC and the Attorney General offered extensive testimony indicating that Consumers (even with the support of ABATE and Hemlock) failed to adequately justify the utility’s proposal to exclude all consideration of energy usage when allocating production-related expenses. This led them to assert that the Commission must reject this portion of the company’s request, and instead retain the existing 4CP 50/25/25 allocation structure. Although still recommending adoption of its own suggested structure, the Staff went on to state (as noted in footnotes 26 and 27 of this PFD, and as described by its cost allocation witness) that the proposal to maintain the current 50-25-25 weighting is also reasonable.

The ALJ agrees with the witnesses offered on this issue by MEC and the Attorney General--and, albeit to a lesser extent, the Staff--that insufficient justification was provided in this case for switching from the current 4CP 50/25/25 production cost allocation structure to either the 4CP 100/0/0 methodology requested as part of Consumers’ application or the 4CP 75/25 allocator proposed by the Staff. Specifically,
the ALJ finds that neither the law governing this matter nor the record assembled in this proceeding support altering the production-related cost allocation previously authorized for use by Consumers. This finding is based on the following six reasons.

First, notwithstanding the apparent belief by at least a few of the parties to this case that Act 169 somehow mandates that Consumers’ production cost allocator must be revised in this proceeding, that is simply not true. As reflected in Section II of this PFD, supra, Act 169 in no way demands that the 50/25/25 allocation structure previously established by Act 286 for application to both production-related and transmission costs—and which is still reflected in that portion of the statute—be replaced by some other structure. Instead, all that Act 169 did was provide the Commission with the opportunity to “modify this method” if the Commission felt it would serve “to better ensure rates are equal to the cost of service.” See, MCL 460.11(1). All that particular change did was essentially restore the Commission’s discretion to pick some other means beyond the 50/25/25 structure that had been mandated by Act 286 for allocating these two types of costs.

Second, at least with regard to Consumers’ proposal, its peak demand-only structure is at odds with decades of Commission decisions. As both described in Section II of this PFD and correctly asserted by Staff witness Putnam, “for at least the past 38 years,” every COSS adopted by the Commission for use in setting Consumers’ rates “has had 25% of the production allocator determined by total energy.” 3 Tr 437-438. Moreover, as can be seen from the orders mentioned in Section II, each of which concerned Consumers’ rate case proceedings conducted during that period, some cases also included between 25% and 50% of the total allocator being assigned
to on-peak energy usage.\textsuperscript{31} The same is true with regard to the other of Michigan’s two largest electric utilities, namely DTE Electric.\textsuperscript{32} As a matter of fact, previous requests by Detroit Edison, ABATE, and other industrial customers for approval of a 100% demand-based production cost allocator have been specifically rejected in the past.\textsuperscript{33} It is thus abundantly clear that, for the past several decades and upon careful consideration throughout, the Commission has consistently concluded that these utilities’ electric generation assets were not built exclusively to serve peak load (with no thought given to the system's energy usage during the rest of the year) and, therefore, the production-related costs arising from these plants should not be allocated solely on the basis of peak demand.

Third, notwithstanding the significant reliance that Consumers, ABATE, and Hemlock place on the Workgroup Report as support for adopting the utility’s proposed 4CP 100/0/0 production cost allocator, that document’s usefulness in this manner is significantly hindered by the MEDC Workgroup’s focus, structure, and operation. With regard to its focus, under the section entitled “Purpose,” the Workgroup Report itself concedes that the MEDC Workgroup was formed “to identify non-legislative options that can reduce electric rates for energy-intensive companies,” as opposed to providing any sort of over-arching or impartial assessment of all available production cost allocation options. Exhibit A-14, pp. 1-3. As for its structure, the record—as described earlier in


\textsuperscript{33} See, i.e., the Commission’s January 21, 1994 order in Case No. U-10102, at pages 81-89.
this PFD--clearly shows that the MEDC Workgroup consisted primarily of large industrial customers, completely excluded all residential- and small commercial-customer advocacy groups that normally participate in rate case proceedings before the Commission, and used members of the Commission Staff solely as technical advisors. See, i.e., 2 Tr 301, 3 Tr 427-428, and Exhibit A-14, pp. 1-4. Finally, with regard to its operation, uncontroverted evidence shows that: (1) of the numerous potential methods described by the NARUC Manual admitted as Exhibit MEC-17, the MEDC Workgroup only evaluated two production cost allocation structures, each of which assigned at least 75% of those costs based upon peak demand, before electing to go with the method that assigned cost on a 100% peak demand basis; (2) it “failed to offer any analytical basis” for reviewing only peak demand methods; and (3) actual minutes of the MEDC Workgroup’s meetings, admitted as Exhibit MEC-25, show that “the objective of the Workgroup was to lower industrial rates as much as possible.” See, 3 Tr 600 and 607; see also, Exhibit A-14.34

Fourth, application of the utility’s proposal to switch to a 4CP 100/0/0 production cost allocation methodology may well not provide affordable and competitive electric rates for all customer classes, as is mandated by Act 169 and set out as one of the keys to the Governor’s previously-mentioned policy goals. Notwithstanding claims to the effect that (1) this proposal will eventually reduce total capacity cost by sending better

34 Although the MEDC Workgroup’s efforts to find a way to advance economic development in Michigan should be lauded, and while the Workgroup Report itself is worthy of respectful consideration when applied in other situations, it is not particularly germane to an overall assessment of how an electric utility’s production-related costs can most appropriately be allocated. This is because, as shown above, it is based on the premise that only peak demand causes utilities like Consumers and DTE Electric to incur fixed production costs. Because the need to produce energy is a major reason for the construction of base load generating plants--as both the record shows and the Commission’s past orders have consistently recognized--this is a mistaken premise. Id.
price signals to customers, thus likely reducing all customers’ rates, and (2) that it is “pure speculation” regarding whether the rate changes that arise from its adoption would, “particularly for the residential rate class, [serve to] make rates unaffordable.” These rather ethereal assertions fail to overcome the more substantive and objective information offered by opposing parties.

For example, working from the graphs he provided in Exhibit MEC-2, Mr. Jester provided the following statistical analysis:

As one can see by examining these graphs, in 2013 Michigan had the 13th highest industrial rates in comparison to the other states. [Consumers’] industrial rates are higher than the Michigan average by enough that it would have ranked 10th compared to the states. If expiration of the E-1 Rate and [Consumers’] proposal had been [in] effect in 2013, its industrial rates still would have ranked 10th compared to the states. All of the states in the East North Central Region have average industrial rates even lower than Michigan’s, and lower than [Consumers’] would be if their proposal were adopted. Expiration of the E-1 Rate together with [Consumers’] proposal would have set its 2013 industrial rates at 24.5% above the East North Central regional average and 23.8% above the national average.

In 2013 Michigan also had the 13th highest commercial rates in comparison to the other states. [Consumers’] commercial rates are somewhat higher than the Michigan average, so that [Consumers’] commercial rates would have ranked 11th amongst the states, without materially changing its position. The 2013 average commercial retail rates of all other states in EIA’s East North Central region were lower than [Consumers’] actual rates and would remain lower if its proposal had been in effect. [Consumers’] proposal would have set its commercial rates at 22.9% above the East North Central regional average and 15.5% above the national average.

In 2013, Michigan had the 11th highest residential rates in comparison to the other states. [Consumers’] residential rates were marginally lower than the Michigan average such that it would have ranked 11th versus the states, excluding Michigan. If expiration of the E-1 Rate and [Consumers’] proposal had been in effect in 2013, its residential rates would still have

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35 ABATE’s reply brief, p. 8. In this particular regard, ABATE continues by asserting that that “only if residential uncollectible expense balloons following the rate changes will we have any indication as to the affordability of [those] changes.”
ranked 11th amongst the states, rising slightly above the Michigan average residential rate in 2013. The 2013 average residential retail rates of all other states in EIA’s East North Central region were lower than [Consumers’] actual rates and would have remained lower if its proposal had been in effect. Expiration of the E-1 Rate together with [Consumers’] proposal would have set its residential rates at 21.2% above the East North Central regional average and 21.4% above the national average. For context, it should be noted that in 2013, . . . Michigan’s median household income was 35th highest amongst the states while all states with higher average residential retail electricity prices have median income well above the national average.

It is apparent from these data that [Consumers’] rates are not competitive nor very affordable, that its current position relative to other utilities and regions is similar across customer classes, that its proposal in this case will not materially make its industrial rates more “affordable and competitive,” and that [Consumers’] proposal in this case will make its residential rates less “affordable and competitive.” In short, the problem [Consumers] and the Commission need to solve is not the allocation of [the utility’s] costs amongst customer classes, but that [its] costs are too high.

3 Tr 491-492. Moreover, as noted above, granting the request of Consumers, ABATE, and Hemlock on this single issue would increase residential customers’ share of currently-approved production expense by between $46 and $55 million annually. 36 See, 3 Tr 607; See also, Exhibit A-12. Certainly, at least for members of the residential rate class, such a change would be difficult to view as somehow making their rates more “affordable and competitive,” as sought by the implementation of Act 169. The same can be said of the Staff’s proposed 4CP 75/25 method, although to a lesser degree (since it would shift a significant--albeit smaller--amount of production-related costs from primary to residential customers).

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36 Based on the sheer magnitude of this shifting of costs onto residential customers (occurring, as it would, after completion of the rate de-skewing previously accomplished under Act 286), the ALJ recommends that the Commission reject the cynical view expressed by ABATE (and quoted in the proceeding footnote) that the best way to judge the issue of affordability as it pertains to residential customers is to impose the change, and then see if they can pay their bills.
Fifth, notwithstanding statements regarding the “value of high load factor customers” to a utility’s system, and the need to somehow “benefit” these customers by reducing the costs imposed on the industrial class, the record does not support these broad statements made in support of the utility’s 4CP 100/0/0 proposal. As noted above, although Consumers, ABATE, and Hemlock contend that high load factor customers are being somehow penalized or punished by the current 4CP 50/25/25 production cost allocation structure, they have failed to prove that the value of those customers to the system exceeds the benefits provided by the existing formula (which, unlike Consumers’ proposal, does not allocate all production expense based on peak demand). In contrast, MEC witness Jester offered testimony showing how a low load factor customer that makes use of the system during off-peak hours may actually benefit the system more than high load factor industrial customers. See, 3 Tr 487-488.

In addition, Mr. Sansoucy presented detailed testimony (supported by a spreadsheet received as Exhibit MEC-23) showing that peaking and intermediate capacity used to serve higher load factor customers can be significantly less expensive than base load capacity, as reflected by his economic analysis of the utility’s purchase of the Juniper power plant. See, 3 Tr 613-615.

Sixth and finally, despite noting that the Staff’s analysis at least “demonstrates an awareness that the cost of base load generation is a very significant portion of total generation assets,” recognizes (unlike Consumers’ proposed methodology) that “there are capacity planning dimensions in determining an appropriate production cost allocation methodology,” and correctly reflects that “base load resources cost more than resources used to meet demand peaks,” witnesses for both the Attorney General and
MEC took issue with several aspects of that analysis. 2 Tr 327; 3 Tr 590. For example, Mr. McGarry testified that the analysis presented by the Staff (1) understates base load capacity required to meet even the minimum load that Mr. Putnam used as a starting point due to its failure to include base load capacity necessary to cover planned and forced outages, (2) does not consider the minimum load during peak periods when that load would be significantly higher, and (3) relies on data from only one year. See, 2 Tr 324-327. For his part, MEC witness Jester asserted, among other things, that the 32.6% ratio of minimum load to maximum capacity relied on by Mr. Putnam was far too low, and that his analysis ignores a standard formula generally used in integrated resource planning. See, 3 Tr 590-593.

For the reasons expressed above, the ALJ finds that an inadequate basis has been shown, in either the record or through the review of pertinent law, for adoption of the 4CP 100/0/0 production cost allocation methodology proposed by Consumers and supported by both ABATE and Hemlock. Moreover, despite the fact that the Staff offered more credible support for its proposal (by clearly showing, as outlined above, that at least 25% of all production-related expense should be assigned on the basis of energy usage), the ALJ finds that the Staff’s presentation on this issue is not persuasive enough to justify its adoption in place of the long-standing 50/25/25-based methodology. It is therefore recommended that the Commission deny both of these requests to supplant the currently-approved 4CP 50/25/25 method.

Despite finding that neither the record assembled in this proceeding nor the law governing the matters relating to this case support altering the production-related cost allocation previously adopted for use by Consumers (thus leading to the above
recommendation that the Commission reject both the utility’s proposal to change from a 4CP 50/25/25 to a 4CP 100/0/0 allocation methodology, as well as the Staff’s suggestion that those costs be allocated on a 4CP 75/0/25 basis), the ALJ recognizes that, being an Administrative Body as opposed to a Court of Law, the Commission may elect to base its decisions--at least in part--on public policy grounds. Should it choose to do so in this proceeding based on its belief that a substantial change in production cost allocation will produce rates that better reflect Consumers’ overall cost of service and will concurrently lead to job creation throughout the utility’s service territory (two assertions that the ALJ does not feel have been adequately demonstrated, at least in this case), the ALJ finds that the best the alternative to the 50/25/25 structure adhered to since the implementation of Act 286 would be the Staff’s proposal to shift to a 4CP 75/0/25 allocation methodology. This alternative finding is based on the testimony offered on this issue by Mr. Putnam, which is described earlier in this PFD and can further be found in the record at 3 Tr 435-439. Although flawed, as pointed out by witnesses for both the Attorney General and MEC, the Staff’s proposal represents at least a reasonable attempt to find a middle ground between the various positions espoused by the parties.

B. Allocation of Transmission-Related Expenses

The second issue to be addressed in this matter concerns the most appropriate method to apply to the allocation of Consumers’ system-wide transmission costs. As opposed to the issue of how to best allocate production-related expenses, there appears to be no dispute among the parties concerning this matter.
As discussed earlier, the utility’s witness on this issue--Mr. Ross--stated that because the company incurs its transmission costs primarily on a demand basis that is consistent with its 12 coincident peaks, using a 12CP 100/0/0 allocation methodology made sense. See, 2 Tr 129. Both the Staff and ABATE expressly support this change from Consumers’ existing allocation structure. See, Staff’s initial brief, p. 14, and ABATE’s initial brief, p. 8. Neither Energy Michigan nor MEC express any opposition to Mr. Ross’s proposal in their briefs. Because the proposed 12CP 100/0/0 method for allocating transmission costs is both unopposed and consistent with the MISO tariff’s effect on cost causation, the ALJ finds that it is reasonable and should be adopted by the Commission.

Before moving on, however, it bears noting that MEC witness Jester expressed an opinion that, at least at some point in the future, these costs should be allocated to both transmission and sub-transmission customers “based on their individual contributions to the twelve-month trailing 12 CP.” 3 Tr 556-557. The Staff’s witness on this issue, Mr. Revere, opposed what he viewed as an inappropriate individual cost allocation, which—as discussed earlier in this PFD—would create an unnecessary step in both the cost allocation and rate design processes. See, 3 Tr 423. Based on the explanation offered by Mr. Revere, as well as the fact that MEC elected not to pursue this matter in its briefs, the ALJ finds that this proposal should not be adopted without further support, and thus recommends that it be rejected by the Commission.

C. Distribution Cost Allocation and Recovery

The next matter to address in this proceeding concerns two issues relating to the recovery of Consumers’ distribution-related expenses. The first involves how those
costs should be allocated to the utility’s various rate classes. The second relates to whether those costs should ultimately be recovered from customers as a percentage mark-up on their respective energy charges.

With regard to the first of these issues, there is (like with the allocation of transmission charges) little dispute among the parties. As noted earlier in the PFD, Consumers’ witness Ross testified in support of the utility’s proposal to use peak class demands at generation, including all electric demands related to its ROA customers, as the way to allocate costs arising from its high voltage distribution assets. This proposed allocation methodology, which Mr. Ross noted was both “consistent with the design and implementation of these assets to meet customer maximum area load requirements,” and was in keeping with the NARUC guidelines regarding this issue, is supported—at least in general—by the Staff. See, 2 Tr 130, and 3 Tr 435. No other parties appear to expressly object to the utility’s proposal in this regard (which, according to Mr. Ross, will increase the costs assigned to primary customers by approximately $2 million, while decreasing the total costs assigned to secondary and residential customers by the same amount). See, 2 Tr 131.

Nevertheless, the MEC recommends that residential and commercial secondary customers should be treated as members of the same class, with no difference in the particular collection of those costs from them. See, MEC’s reply brief, pp. 23-24. In addition, and as explained by MEC witness Jester, the MEC appears to recommend using a percentage mark-up on energy delivered to a customer (which would, assuming

37 Although MEC witness Jester offered testimony differing from both Consumers and the Staff regarding “the allocation of [distribution] costs within a voltage level,” he did not oppose their suggested allocation of these expenses “to a voltage level.” 3 Tr 558.
the adoption of time-of-use rates, vary based on whether that usage occurred during on- or off-peak periods). By way of Mr. Revere’s rebuttal testimony, the Staff asserts that although it agrees that “it is theoretically possible that some portion of distribution costs may be related to increased wear and tear on the system at times of high load,” this particular portion of total distribution-related expense (1) “is not identified” in the record, (2) is “likely not the majority of distribution costs,” and (3) and is also “likely not reflective of marginal cost.”

Based on testimony offered in this regard by Consumers’ witness Ross, MEC witness Jester, and Staff witness Revere, the ALJ finds that (1) the distribution cost allocation proposed by the utility--involving the use of peak demand at generation--should be adopted by the Commission, and that (2) although the assessment of distribution costs to residential and secondary customers on an equal basis (and possibly collected through a percentage mark-up structure) holds promise, the need for additional information in this regard necessitates deferring any action on MEC’s cost recovery proposal to either Consumers’ on-going rate case or some subsequent proceeding.

38 In this regard, Mr. Revere testified that:

The customer-related marginal cost would be that incurred to attach an additional customer to the system, e.g. the cost of the service drop, meter, and additional customer service and billing costs. This is, in essence, the basis for the Staff's calculation of customer charges, at least for residential customers. The demand-related marginal cost is highly-dependent on the specific costs of the specific customer (new substation, line extension, larger transformers, etc.) and therefore have essentially no reasonable use when discussing costs on average. [MEC] witness Jester fails to provide evidence supporting what portion of distribution costs are actually related to this potential cost-causative element.

3 Tr 425. For these reasons, Mr. Revere stated (and the Staff apparently argues) that basing ultimate cost recovery from these customer groups on a percentage mark-up basis should not be adopted, at least at this time. See, Staff's initial brief, pp. 20-22, and 3 Tr 426.
As a result, the ALJ recommends that the Commission approve Consumers’ proposed distribution cost allocation, but defer ruling on the issue of MEC’s specific cost recovery proposal to a subsequent proceeding.

D. Allocation of Customer-Related Costs

The allocation of customer-related expenses gave rise to two general areas of dispute. The first concerns the utility’s proposal to revise the way its customer assistance expenses were allocated in the underlying COSS study used in its last rate case, namely Case No. U-17087. The second concerns somewhat-related requests by Energy Michigan to (1) require the company to adopt the total cost of service method for allocating UAEs, and (2) separate UAEs into a distribution portion and a power supply portion within the customer class to which they are ultimately assigned.

As discussed earlier, Consumers contends that its existing structure concerning the allocation of its customer-related expenses is generally reasonable and should be retained, except for one proposed change. Specifically, the utility seeks to revise the allocation of Other O&M expenses attributable to FERC Account 908, Customer Assistance Expense, to remove various LIEEF- and EO-related costs and have them reassigned to other cost-of-service line item inputs used in computing the company’s COSS. Again, as noted above, this request is based on the company’s assertion that including these expenses as a part of Account 908 when Consumers performed its underlying COSS (i.e., “the Case No. U-17087 final cost-of-service model”) was a mistake, and that this proceeding is the best vehicle for correcting that error. 2 Tr 132. However, as disclosed by Consumers’ witness Ross, making this suggested change would serve to raise the customer-related costs allocated to residential customer by $18
million annually and reduce those assigned to the utility’s primary customers by approximately the same amount, while leaving the expenses assigned to secondary customers effectively unchanged. See, Id.

The Staff responds to this proposal by asserting that, although allocating these particular costs somewhere other than as a part of FERC Account 908 might make sense from a theoretical standpoint, its witness on this issue--Mr. Putnam--correctly noted that “the change should not be made in this case.” Staff’s initial brief, p. 15. According to the Staff, and as it argued in Consumers’ most recent fully-litigated general rate case, namely Case No. U-16794 (Case No. U-17087 having been resolved by settlement), the allocation of customer assistance expenses like LIEEF and EO costs must be considered in conjunction with UAEs. See, Id., citing 2 Tr 440. This makes sense, the Staff contends, because each of these costs (specifically, those relating to LIEEF, EO, and UAEs) all arise from the utility’s overall operations. However, the Staff notes that the company has not proposed making any change regarding its existing allocation of UAEs in the case at hand. As such, the Staff recommends that “no changes be made to the customer assistance expenses” as proposed by Consumers in this proceeding, thus leaving the entire matter for resolution in a subsequent rate case. Id., p. 16. In the alternative, it asserts that if the Commission accepts the utility’s proposed change regarding the allocation of LIEEF and EO costs, it “should also reallocate the Company’s uncollectible expense.” See, Id., citing 3 Tr 442.

MEC supports the Staff’s assertion in opposition to Consumers’ proposed change to the allocation of customer assistance costs. See, MEC’s reply brief, p. 23. It further expressed support for the Staff’s claim that no such change should be made with
regard to those LIEEF- and EO-related expenses “without a corresponding reallocation of the company’s [UAEs].” Id. In contrast, ABATE contends that the Staff’s alternative position, which would effectively allocate UAEs across all rate classes on the basis of billed sales, should be rejected on the grounds that—because it would “reduce costs for Residential customers by $29 million, and would increase costs for Secondary and Primary customers by $5 million and $23 million, respectively”—it is “directly contrary to the Governor’s desire to make Michigan a more attractive place for energy-intensive businesses to locate or expand.” ABATE’s initial brief, p. 13.

Taken as a whole, the ALJ finds that the testimony and arguments offered by the parties and detailed in Section III of this PFD support rejecting Consumers proposal to revise the allocation of its customer-related costs by removing, in the context of this proceeding, all expenses arising from its LIEEF and EO programs. Instead, it appears that the more appropriate place for deciding what should be done with regard to both these expenses and the utility’s UAEs is in the context of a general electric rate case, be it the ongoing proceedings in Case No. U-17735 or elsewhere. As previously advocated by the Staff, and currently supported by the MEC, all three of these components of the company’s system-wide operations should, for the sake of fairness, be carefully considered side-by-side, and the best place for doing so would appear to be in such a case. As a result, the ALJ recommends that the Commission reject both the Company’s proposal in this regard, as well as the alternative treatment suggested by the Staff.

We next turn to Energy Michigan’s requests to alter the current treatment of Consumers’ UAEs. With regard to its first request, Energy Michigan points out that the
utility currently “allocates total uncollectibles to various rate classes by the number of customers in each rate class.” Energy Michigan’s initial brief, p. 1. Instead, and as was suggested by its witness--Mr. Zakem--Energy Michigan contends that UAEs should be allocated “in a general and equitable way to all rate classes to be paid by all customers” by use of the total cost of service method (which, it notes, is the same method used to allocate the discounts for Rate E-1, Senior Citizens Rate members, and those taking service on the Income Assistance Rate).\textsuperscript{39} Id., p. 2. In support of this proposed change, it claims that Consumers is essentially confusing an overhead cost with cost causation, citing testimony from Mr. Zakem (which is quoted in Section III of this PFD) to the effect that (1) the amount of a rate class’s UAEs is in no way determined by the electric use characteristics of that class, (2) other members of that class who pay their bills do not cause UAEs to arise, (3) no logical basis exists for allocating UAEs based solely on the how many other customers happen to be in the same rate class as a paying customer, (4) the outcome of the utility’s existing methodology--by which the Primary class receives an allocation of merely $65,000 of Consumers’ annual $30,505,000 in UAEs--is patently unreasonable, and (5) UAEs are essentially a company-wide overhead cost, developed independent of the electric use of any particular rate class. \textit{See}, Id., citing 3 Tr 624.

Consumers opposes Energy Michigan’s request on the grounds that “the existing method of allocation, relative to gross write-offs, reasonably reflects how the Company incurs these costs. \textit{See}, Consumers’ reply brief, p. 23, citing 2 Tr 151. In addition, the utility contends that “there is no fundamental societal benefit related to these costs” that

\textsuperscript{39} Moreover, as mentioned earlier in this PFD, the total cost of service method is what DTE Electric uses for allocating its UAEs.
could possibly justify the broad allocation of UAEs (as requested by Energy Michigan) because “these expenses are clearly attributable to the actions of a certain class of similarly situated ratepayers.” Id.

Notwithstanding Consumers’ assertions to the contrary, the ALJ finds Energy Michigan’s above-stated arguments persuasive on this point. While similarities among members of various classes may be useful for projecting patterns of energy usage and assigning associated costs, such similarities have little (if any) relevance when it comes to allocating UAEs. Not only do customers who pay their respective bills do nothing to contribute to the utility’s overall level of UAEs, but there is little (if anything) they can do to reduce the amount of UAEs experienced by the company. As such, the ALJ recommends that the Commission adopt Energy Michigan’s proposal to require Consumers to begin allocating its UAEs on a total company cost of service basis.

As for its second UAE-related request, Energy Michigan notes that the utility currently includes all of its UAEs in the distribution portion of its customers’ monthly bills. According to its witness, Mr. Zakem, doing so is illogical because if a customer fails to pay its bill, that unpaid bill includes both distribution charges and power supply charges, and thus the “distribution portion should be included in the distribution rates and the power supply portion should be included in power supply rates.” 2 Tr 626. According to Energy Michigan, this is particularly unfair to ROA customers who, because they take only distribution service from Consumers, are essentially being forced to compensate the utility for power supply customers that fail to pay their power supply charges. See, Energy Michigan’s initial brief, p. 4. Energy Michigan therefore asks that the
Commission “require Consumers to separate the allocation of [UAEs] into a distribution and a power supply portion.” Id.

According to Consumers, there is no logical rationale for separating UAEs into distribution and power supply components. See, Consumers’ reply brief, p. 23. Citing testimony provided by Mr. Ross, the utility asserts that a UAE is, in essence, the “recognition that an asset on the Company’s books is no longer valid” and, as a result, is “not tied directly to any revenue earned by the Company.” Id., citing 2 Tr 152. Instead, it continues, UAEs are simply “an accounting recognition, pursuant to FERC Account 904, that an account receivable is no longer valid.” Id. Thus, Consumers continues, because these amounts are “tied to asset balance sheet values and not income statement revenues,” it would be a violation of general cost-causation principles to “re-functionalize these amounts based on distribution and power supply revenues” (as Energy Michigan’s proposal would do). Id., citing 2 Tr 152. Finally, the utility goes on to note that “the NARUC Manual specifically indicates that customer-related costs, like UAEs, are typically assigned solely to the distribution function. Id. The company therefore argues that Energy Michigan’s request in this regard should be rejected.

The ALJ finds Consumers’ arguments on this particular issue persuasive. As explained by Mr. Ross, logic does not support collecting UAEs separately for distribution and power supply expenses. Moreover, recovering them (like most other customer-related costs) through distribution charges is more in keeping with the treatment of such costs as recommended by the NARUC Manual. As a result, the ALJ recommends that the Commission reject Energy Michigan’s second proposal, and instead authorize
Consumers to continue including all of its UAEs in the distribution portion of its customers’ monthly bills.

E. Rate Design and Various Related Issues

In the course of this proceeding, numerous proposals were offered regarding how the utility’s actual rates should be structured and how its tariffs should read. Consumers’ suggestions were presented by Ms. Collins, a detailed description of which are set forth in Section III of this PFD, supra. Discussions of those offered by the other parties to this case can also be found there.

1. Subsidized Rates and the Collection of Subsidies

In developing the utility’s rate design, Ms. Collins started with the jurisdictional costs for “the rate classifications for Power Supply and Delivery, and determined the amount of subsidies and how those subsidies would be collected.” Consumers’ initial brief, p. 19, citing 2 Tr 44. In this regard, she noted that the company is proposing to continue the Senior Citizen and Income Assistance Provision discounts currently included in Consumers’ electric rates, and is likewise proposing to continue allocating capacity costs to MMPP Rate customers at approximately the same level as has been approved for use in the utility’s existing rates. See, Id. With regard to the allocation of capacity to MMPP customers, Ms. Collins continued, the company suggests assigning approximately $7.7 million to these customers (which is “roughly equivalent to the amount allocated to this class under the Commission approved rate design in Case No. U-17087”), and correspondingly removing the same amount of costs from all other ratepayers based on the allocation of capacity from the test-year COSS. 2 Tr 45.
None of the parties expressed objection to the above-stated actions. Thus, based on Ms. Collins’ testimony, the ALJ finds that Consumers’ proposals regarding the rate design treatment of customers taking service on its Senior Citizen, Income Assistance Provision, and MMPP rates should be approved.

2. GPD Rate Design Changes

The next general area addressed in her testimony concerned suggested revisions to the utility’s GPD rate design. The first proposed change in this regard concerns how to best handle the capacity costs that Consumers’ proposal would allocate to its interruptible rate GPD customers taking service under the GI Provision. As noted earlier, because the utility does not plan for (let alone purchase) capacity for these interruptible customers, Ms. Collins testified that “an appropriate amount of capacity costs allocated to [them] needs to be removed [from their on-peak demand charge] and spread to other customers.” 2 Tr 45-46. The company is proposing to do this by continuing its current summer-based GI credit, but with that credit being increased from its existing level of $6.00/kW to $7.00/kW, and allocating the cost of those credits “to other customers based on the manner in which [Mr. Ross’s] Test-Year COSS allocates total capacity costs.” 2 Tr 46.

The Staff specifically expresses support for this proposal on the grounds that, although these customers are initially allocated capacity costs like all other GPD customers, the fact that their service can be interrupted during periods of peak demand means that some method must be implemented to compensate their willingness to

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40 To the contrary, the Staff specifically expressed support for Consumers’ proposed treatment of the MMPP rate class and the allocation of its capacity costs. See, Staff’s reply brief, p. 10.
reduce system load when needed. See, Staff's initial brief, pp. 17-19. Moreover, as with the prior issue, none of the parties oppose the utility's suggested change. The ALJ thus finds that Consumers' proposed change regarding both the size and allocation of the GI credit for GPD customers is reasonable, and recommends that it be adopted by the Commission.

The second potential modification to Consumers’ GPD rate design (which has proven to be its most controversial) concerns the utility’s proposal to collect about 75% of this customer class’s capacity costs through the on-peak demand charge, with the remaining 25% assessed against these customers based upon their energy consumption. According to Ms. Collins, this would replace the existing structure, which assigns only 50% of these costs to demand, with an equal amount allocated on the basis of energy usage. See, 2 Tr 47. Moreover, she continued, increasing the percentage of capacity-related expenses to be allocated based on peak demand (as the company proposes) aligns with the MEDC Workgroup’s recommendation that “proper rate design should collect fixed costs through demand charges.” Id., citing Exhibit A-14.

As with Consumers’ preceding rate design issues, the Staff agrees with the utility’s proposal to adopt the 75% demand charge/25% energy charge method for recovering the fixed capacity costs allocated to GPD customers. See, Staff’s initial brief, p. 18, citing 3 Tr 464. However, Hemlock and ABATE strongly oppose the company’s proposal to merely move from assigning these costs on a 50/50 basis to a 75/25 structure. According to them, 100% of these fixed capacity costs should immediately be assigned to GPD customers through demand charges, with none collected through energy charges. See, Hemlock’s reply brief, p. 4, and ABATE’s Initial
brief, pp. 13-14. Doing so would, Hemlock asserts, be “consistent with cost causation principles,” and reduce the likelihood of creating an unreasonable intra-class subsidy. Hemlock’s reply brief, pp. 4 and 9.

The ALJ does not find the arguments made by Hemlock and ABATE persuasive for the following reasons. First, it appears that their suggestion to collect all fixed capacity costs from GPD customers through demand charges would produce inequitable results for most of Consumers’ GPD customers. Specifically, upon analyzing their 100% demand charge proposal, Ms. Collins testified that it would “substantially hurt customers with lower load factors” and only provide “a small benefit to higher load factor customers” within the GPD rate class. 2 Tr 53. In this regard, the utility notes:

Ms. Collins specifically explained that 60% of GPD rate customers have load factors below 60%. This means that a majority of GPD rate customers would not see any benefit if [Hemlock’s] proposal was approved by the Commission. The variance, in customer impacts, between the Company’s proposal and [Hemlock's] proposal is shown in Exhibit A-15 (LMC-9). As demonstrated by this exhibit, customers with a 90% load factor would see their savings increase from 13.7% to 17.4% under [Hemlock’s] proposal. See, Exhibit A-15 (LMC-9), line 19, columns (e) and (f). Conversely, a customer with a 40% load factor would go from a 0.6% decrease in costs under the Company’s proposal to an 8.8% increase under [Hemlock’s] proposal. See, Exhibit A-15 (LMC-9), line 24, columns (e) and (f).

Consumers’ reply brief, p. 21. Second, Hemlock’s assertion that an unreasonable intra-class subsidy would arise from the utility’s proposal rings hollow based on the fact that the highest-load factor GPD customers would actually be paying a lower average rate than all other customers.

This fact is illustrated by the Exhibit A-3 (LMC-3) which shows present revenue, based on the expiring Rate E-1 rate, and proposed revenue, based on the Company’s proposed GPD rate design, which the Rate E-1 customer will join once Rate E-1 expires. The proposed revenue for the
former Rate E-1 contract rate under GPD is $137 million [See, Exhibit A-3 (LMC-3), line 17, column (c)], while if Rate E-1 was its own rate class, it would have a cost of service of $154 million. See, Exhibit A-4 (LMC-4), column (i). This comparison demonstrates that the high-load factor customer previously served under Rate E-1 is actually paying less under the Company's proposed rate design than if their cost of service had been determined separately.

Id., pp. 21-22, citing 2 Tr 54. Based on the analyses set forth above, the ALJ finds that arguments by Hemlock and ABATE in support of their proposal to collect 100% of Rate GPD's allocated share of fixed capacity costs through on-peak demand charges should be rejected, and that Consumers' proposal to assign 75% of these costs through such capacity charges (with the remaining 25% collected through energy charges) should be adopted by the Commission.

The third rate design change suggested by the utility was to revise the delivery charge assessed to GPD customers. Specifically, although the company proposes to continue imposing the $100 per month System Access Charge, it seeks authorization to begin collecting the remainder of its delivery costs through the Maximum Demand Charge. See, Consumers' initial brief, p. 23, citing 2 Tr 55. Furthermore, and as noted earlier in this PFD, the utility contends that the same rate design change "be carried through" to its GPTU, MMPP, and GSG-2 rates as well, because their delivery charges are set in the same manner and at the same level as GPD customers' rates. Id.

As noted by the Staff, Consumers' proposal would replace its current structure, under which it recovers delivery costs through three charges, namely (1) a system access charge, (2) a maximum demand charge, and (3) and a per kWh distribution energy charge. See, Staff's initial brief, p. 18, citing 3 Tr. 465. Thus, under its proposal, the utility would effectively eliminate the distribution energy charge. The Staff supports
this change on the basis that, because distribution expenses are primarily driven by demand and the number of customers receiving service (as opposed to energy consumption), the company’s request to recover all of these costs for the GPD rate “through the demand and customer charges better reflects cost causation principles.” Id., p. 19. No other parties addressed this matter in their briefs.

For the reasons expressed by the Staff, the ALJ finds that Consumers’ proposal to modify the delivery charge assessed to its GPD customers is reasonable, and recommends that the Commission grant the utility’s request to make this change.

3. Educational Institution, GS, GSD, GP, and GPD Credits

The final set of rate design changes proposed by the utility (which were also described in detail as part of Section III of this PFD, supra) involve the creation of credits to be made available to various rate classes. The first of these is the GEI, which is a credit provision intended to meet Act 169’s requirement that public and private schools, universities, and community colleges receive service at rates equal to their actual cost of service. See, Consumers’ initial brief, p. 23. For Rate GS and GSD customers, Ms. Collins testified that the utility is seeking to provide a delivery credit “that would remove the subsidies for Income Assistance and Senior Citizen” rate class members. 2 Tr 48. Finally, she noted that the company seeks approval for power supply and delivery credits to be made available to GP and GPD customers in order to set their bills at the cost of service levels developed for them in Mr. Ross’s COSS. Id.

Again, because none of the parties have expressed opposition to the adoption of these provisions as described by Ms. Collins, the ALJ finds that they are reasonable and recommends that they be approved by the Commission.
4. **Rate GPD High Load Factor Subclass**

For its part, Hemlock asserts that Consumers should be directed to develop and offer, as part of its next general electric rate case, a high load factor subclass within Rate GPD. According to Hemlock, “creating a high load factor classification will achieve many of the objectives” set forth in the Workgroup Report. Hemlock’s initial brief, p. 11. In support of this assertion, Hemlock cites statements contained therein to the effect that high load factor customers benefit the system, and that the cost of serving those customers is less than that required to serve low load factor customers. See, Id. Thus, Hemlock concludes that because establishing the type of sub-group it envisions “would allow for more accurate cost allocation to high load factor customers,” and “would eliminate the improper subsidization that currently exists between Rate GPD customers with high load factors and Rate GPD customers with low load factors,” its request should be approved.

As specifically discussed in Section IV(A) of this PFD, the MEDC Workgroup’s focus, structure, and operation substantially reduced the reliability of its ultimate conclusions. Moreover, as is also discussed above, the self-serving statements concerning “value” of high load factor customers to a utility’s system, etc., are not actually supported by the record. Finally, as pointed out by the utility, there is no need to “place high load factor customers into a separate cost-of-service column in order to achieve rate savings” for them. Consumers’ reply brief, p. 22. Rather, the company notes, it “was able to achieve a rate reduction for high-load factor GPD customers through the rate design adjustment of changing demand charges in the existing GPD rate schedules.” Id., citing 2 Tr 56.
As a result, the ALJ finds no need to require Consumers to develop, test, and offer the sub-group sought by Hemlock in the context of its next rate case filing, and recommends that the Commission reject Hemlock’s proposal in this regard.

5. Dynamic/Time-of-Use Rates

As mentioned repeatedly in this PFD, MEC recommends that the Commission require Consumers to phase in time-of-use rates for all customers with AMI meters. See, MEC’s initial brief, p. 42. As discussed above, MEC’s witness, Mr. Jester, testified extensively regarding the importance of sending accurate price signals and using dynamic or time-based rates to do this. MEC supports his recommendations to the effect that the capacity component of Consumers’ production-related costs should be recovered through dynamic peak pricing when system load exceeds a pre-approved threshold. Specifically, all production expenses caused by usage above that level would be recovered through an energy charge that has a time-of-use element. For example, Mr. Jester testified that:

Total revenue to [Consumers] will remain the same in the short run as a result of this case, even if the pricing reforms I recommend are adopted. The principles that determine required revenue will also remain unchanged. However, these pricing reforms will lead to reduced need for [Consumers] to make future investments in generation capacity and in transmission and distribution capacity; will reduce energy costs for line-losses; and will reduce distribution system maintenance costs. These reduced future costs will largely result from the use of time-based rates reflecting full marginal costs at high-load times, to which customers will respond by either being more efficient in their use of electricity at high cost times or by shifting their uses of electricity to lower cost times. This customer response to pricing incentives will reduce system peak loads and increase system load factors.

The availability of low-cost electricity at non-peak-load times will also likely encourage customers to shift to electricity from other energy sources by, for example, increasing their use of pluggable electric vehicles or of electricity-based space heating technologies. If they are able to make these switches
voluntarily because of these lower electricity process that reflect lower marginal costs, then customer welfare will increase. [Consumers] may even increase its revenue in the long-run as the pricing reforms lead to greater productivity in its investments due to the leveling of load and the increased responsiveness of load to power supply conditions.

It is particularly useful to undertake these pricing reforms now when Consumers is projecting concerns about generation resource adequacy that may lead to potentially avoidable new generation investments if appropriate rate design reforms are not undertaken in time.

3 Tr 510-511.

MEC argues that its proposal is the only one offered by any party that would actually send effective price signals to customers, and that it is also the only proposal that attempts to produce affordable and competitive rates for all customer classes by having the potential to reduce total system costs. It thus argues that its dynamic pricing/time-of-use proposal best meets the requirements of Act 169, and cites testimony offered by Mr. Jester estimating savings of $65 million annually from effective pricing programs targeted at residential customers alone. See, MEC's initial brief, pp. 30-31. MEC also cites the testimony of witnesses offered by other parties (e.g., Attorney General witness McGarry and ABATE witness Selecky) who both emphasized the importance of sending price signals to control peak load costs. See, Id., pp. 31-32.

For their part, the Staff, Consumers, and ABATE each argue that it is premature to adopt rate design structures that rely to such a great extent on data received by customers from their respective AMI meters, as does MEC's proposal. For example, Staff witness Pung addressed this in his direct testimony, after indicating that Consumers’ proposals cannot currently send accurate price signals to its customers, stating that:
Staff recommends that the Company present a plan in its next rate case for how such a price signal could best be sent to those customers currently not receiving it upon the completion of AMI rollout.

* * *

In Staff’s opinion, it would be inappropriate to put a rate in place which could only send the appropriate price signal to some customers based, not on a choice made by that customer, but on the Company’s AMI rollout schedule. This could lead to some being able to benefit from changing their demand at the system peak while others could not, though not by their own choice.

3 Tr 466. Likewise, Staff witness Revere noted that because the proposals offered by MEC’s witness “rely on the data AMI meters provide,” Mr. Pung’s assessment was correct, in that:

[A]ny rate design proposals relying on such data are appropriately left for when AMI meter deployment is complete. Staff’s position on this matter extends to any allocation proposals that rely on these same data.

3 Tr 422.

With regard to this issue, ABATE expresses concurrence with the position articulated by Mr. Pung and quoted above. See, ABATE’s initial brief, p. 11. Specifically, it agrees with the Staff’s conclusion that the cost allocation and rate design proposals offered by MEC witness Jester “can only be implemented in conjunction with a final roll-out of the AMI meters.” Id. ABATE also expresses concern that MEC’s proposed use of dynamic/time-of-use pricing could inadvertently result in some level of “revenue instability, particularly if the concept of relying on individual customer billing determinants instead of class billing determinants [is adopted].” Id., p. 12.

Among other things, Consumers argues that--at least as currently presented by Mr. Jester--MEC’s recommendations “are premature and otherwise inappropriately allocate the Company’s costs.” Consumers’ reply brief, p. 13. Specifically, the utility
points out that, although MEC’s dynamic peak pricing proposal relies on the deployment of the company’s AMI meters, the full deployment of these meters will not be achieved until approximately the end of 2016 or possibly sometime in 2017. See, Id. “As explained by Company witness Collins,” Consumers continues, “as of the end of 2014, the Company’s AMI meters were only 21% deployed.” Id., citing 2 Tr 56, 57, and 65. According to the utility, “implementing customer-wide rates on an emerging technology that has not yet been fully implemented is simply not prudent.” Id. Furthermore, Consumers asserts that (1) the MEC’s proposal represents a radical change for many customers, thus raising the specter of mass confusion, and (2) no evidence has been produced to show that dynamic peak pricing will actually result in more competitive and affordable rates. See, 2 Tr. 57. The company currently has several demand-response rates in place, it continues, and will need both more time and information to “determine the customer impacts before making any type of customer-wide transition” to the type of rates proposed by MEC. See, Consumers’ reply brief, p. 13.

Taken as a whole, the ALJ finds that—as attractive as it appears—the request by MEC to require Consumers to implement dynamic/time-of-use pricing should not be granted at this time (even on a partial, opt-in basis for those who have already had smart meters installed on their property). As noted by both Mr. Pung and Mr. Revere, it would be inappropriate to establish a rate that could only send the appropriate price signals to some of a particular rate class’s customers based, not on any choice made by those customer, but simply on the utility’s AMI roll-out schedule. Such a situation could prove unfair to one segment of a rate class where, for example, some members are allowed to benefit from their use of time-of-use based rates while other members have
no such ability simply due to geography or the timing of Consumers’ AMI installation program. Moreover, testimony provided in this case reflects that Consumers is actually in the early stages of its AMI installation program, having only deployed smart meters at only 21% of its customers’ structures, and may be as much as two years from completing the project. Finally, notwithstanding MEC’s concerns regarding the possibility of having to wait an inordinate amount of time between the actual completion of Consumers’ AMI roll-out and the filing of a rate case in which the concept of dynamic/time-of-use pricing can be fully assessed and (potentially) implemented, it should be noted that--based on recent history--such a wait would likely be quite brief. Specifically, over the last five and one third years, Consumers has filed four general electric rate cases, the most recent of which is due for a final order of the Commission by early December of 2015.41

The finding described above should not be construed in any way as taking an adverse position regarding the asserted merits of shifting Consumers toward a system that more fully incorporates the type of dynamic and time-of-use pricing (as well as cost allocation) structure sought by MEC. To the contrary, it appears that the benefits--to utilities and ratepayers alike--of establishing such a system could well be significant. However, the ALJ concludes that the proposal offered by MEC in the current case is premature. It is therefore recommended that the Commission deny MEC’s request in this regard.

6. New Low-Income Household Rate

The next rate design proposal offered by MEC concerns its request to have the Commission create a Low-Income Household Rate which, according to Mr. Jester, could use the statutory eligibility criteria set forth in MCL 460.10t(6)(b) and referenced in MCL 460.11(8). See, MEC's initial brief, p. 42, citing 3 Tr 576-579. Mr. Jester testified extensively on this issue, asserting that the easy identification of customers in this class “will enable more consistent and appropriate implementation of public policy concerning service to low-income households.” 3 Tr 572. Along these lines, he stated that participation in this rate schedule should be conditioned upon the customer’s agreeing to (1) permit Consumers to “control some of the customer’s appliances, if and when the company implements such controls,” (2) participate in the utility’s EO program for low-income customers, and (3) allow the company to install “price-responsive intelligent communicating thermostats and in-home displays” in the household. 3 Tr 577 and 579. Finally, he recommended that, upon implementation of this rate, “the company undertake to develop a combined natural gas and electricity budget plan for its low-income customers who receive both services” from Consumers. 3 Tr 579.

The utility asserts that the Commission should reject this proposal on the grounds that it is unnecessary, pointing out that it “duplicates low-income rates” that are already available to its customers. Consumers’ initial brief, p. 30. For example, the utility continues, Ms. Collins specifically testified that:

The Company currently has low-income programs in place. First, the Company offers a $7 monthly credit for eligible low income customers under the income assistance program. Second, the [Commission] recently approved an extension of the Company’s Consumers Affordable Resource for Energy pilot. The purpose of this pilot is to support participating
customers in establishing new habits of on-time monthly payments and energy usage awareness in order to break the cycle of need and transition the customer to self-sufficient energy account management. In addition, the Company recently concluded the Clear Control Pilot Program. This was a collaborative pilot to evaluate whether different ways of providing customer information on energy use, and a different paradigm for customer billing, can help low-income customers reduce consumption while improving their payment performance. The pilot was successful and a follow-up study is being planned.

2 Tr 57. None of the other parties to this proceeding elected to take a position with regard to MEC’s proposal.

Although conceding that there may be some merit in connecting low-income rate assistance to demand-side management programs tailored for use by low-income customers, as the structure outlined by Mr. Jester would do, the ALJ finds that this proposal should be reserved for analysis in some future general electric rate case. Hopefully, at that point, the overall effectiveness of Consumers’ past and current efforts in this regard can be evaluated on a side-by-side basis with the asserted benefits of instituting a low-income household rate like that proposed here. Nevertheless, based on the overlap between Consumers’ existing low-income programs and studies, on the one hand, and what would arise from MEC’s suggested rate, on the other, the ALJ recommends that the Commission deny MEC’s request to implement its proposed Low-Income Household Rate at this particular time.

7. Assigning Customers to the Least-Costly Tariff

The last of MEC’s proposals concerning matters of rate design, and one that serves as an adjunct to its request for the implementation of dynamic/time-of-use rates, is its request that Consumers be required to automatically transfer customers to the
most advantageous rate for which they are eligible. See, MEC’s initial brief, p. 41. In this regard, Mr. Jester testified that:

Calculating the least costly rate schedule is often difficult to do by manual methods, so finding the least costly rate schedule can be a burden to utility customers. These calculations may also require billing history data that will only be available to customers if they are deliberate and systematic about retaining the data over a period of a year or more. With more complex rate designs, it may be impractical for utility customers to make the necessary calculations. On the other hand, with computer assistance it can be a fully-automated process for the utility. Thus placing the responsibility on the utility significantly lowers the decision and transaction costs to society as a whole by making large reductions in these costs to customers while imposing only a small cost on the utility.

Giving customers the opportunity to opt out of the least costly rate schedule provides them as much free choice as requiring them to opt in to a rate schedule. A customer who prefers a more costly rate schedule for some reason rather than accept reassignment to the least-costly one proposed by the utility can still make that choice.

3 Tr 523. This proposal is based on the belief that “public policy should assume that the least costly tariff is what a utility customer prefers unless the customer explicitly chooses otherwise.” MEC’s initial brief, p. 41.

The Staff takes issue with this proposal for several reasons. First, the Staff notes that (in what appears to be an attempt to increase the number of customers that would make use of MEC’s recommended dynamic/time-of-use pricing) this proposal “falls just short of forcing customers into a different rate design.” Staff’s initial brief, pp. 24-25. In its opinion, “it is not appropriate to transition customers to a new rate by default.” Id., at 25. Second, the Staff contends, MEC fails to recognize that, although Consumers has data showing “what would have been a lower cost rate for the customer in the past,” the utility has “no way of knowing what the least cost rate will be for any given customer now or in the future.” Staff’s reply brief, p. 18. In this regard, the Staff points out that a
customer’s “usage or the times of that usage could change significantly at any point for reasons the Company is unaware of.” Id. As a result, it contends that MEC’s proposal should be rejected.

The ALJ agrees with the Staff. The public interest would, it seems, be best served by allowing utility customers to make their own decisions regarding which rate best suits their individual needs or desires. Moreover, and as correctly noted by the Staff, MEC’s proposal would be backward-looking, in that customers would be assigned to rate classes based solely on historical--as opposed to anticipated--electric usage. Finally, one of the potential benefits expected from adopting this proposal (namely, increasing the usage of dynamic or time-based pricing) may not come into existence, based on the earlier-stated recommendation not to implement such pricing in this case. The ALJ thus recommends that the Commission reject MEC’s proposal.

8. Proposed Tariff Changes

By way of Exhibits A-7 and A-8, Ms. Collins set forth Consumers’ proposed revised tariffs and an explanation of the suggested language changes.42 Of particular note, she stated, were those concerning “changes to the tariff for Adjustment to Power Factor,” which were necessary to “keep the Power Factor Credits and Penalty at the same level . . . approved by the Commission in the Company’s previous electric rate case, Case No. U-17087.” 2 Tr 49. None of the parties specifically expressed concern with these proposed changes. As a result, the ALJ finds that the utility’s suggested tariff

42 As noted earlier in this PFD, Mr. Jester offered a large number of proposed tariff revisions on behalf of MEC. However, because they generally relate to various proposals that were rejected earlier in this PFD (such as MEC’s request to implement dynamic pricing, establish a Low-Income Household Rate, etc.), the question of whether or not to adopt those revisions is essentially moot.
revisions are reasonable and recommends that (at least to the extent that they correspond to the final order issued in the present case) they be approved by the Commission.

F. Miscellaneous Requests

In addition to the matters addressed above, two miscellaneous matters were raised, at least initially, by MEC. These included basing stand-by charges on the cost of combustion turbines, and exempting customers with behind-the-meter capabilities from various cost assignments. However, because neither matter was specifically discussed in the parties’ briefs, and because they both arose from a proposal that has been rejected earlier in this PFD (namely, MEC’s request to implement dynamic/time-of-use pricing), they need not be addressed at this time.

G. Effective Date

The final area of dispute in this case concerns when any of the rate and tariff changes necessitated by the Commission’s final order in this proceeding should take effect. As noted early in Section III of this PFD, Consumers’ witness on this particular issue (Mr. Stebulski) testified that these changes should only apply to service rendered on and after December 1, 2015, thus coinciding with the cut-off date set forth in Act 169. See, 2 Tr 226. Moreover, the utility contends that (particularly in light of the expiration of Rate E-1, and the vast subsidy that it entailed, on November 30, 2015) implementing all changes on that date “will provide the most reasonable impacts on the Company’s customers and would be the least administratively burdensome to the Company.” Consumers’ initial brief, p. 7.
ABATE objects to the utility’s proposed effective date, citing testimony from its witness to the effect that “the rates should be effective with the Final Order in this case,” and that “ratepayers should not have to wait until December 1, 2015 for the rate realignment.” ABATE’s initial brief, p. 14. According to this intervenor, “there is no valid reason to delay the rate realignment” stemming from this case. \textit{Id.}

The ALJ disagrees with ABATE, and finds that the utility’s proposal to have any rate and tariff changes arising from this case take effect on December 1, 2015 is the best course of action. Consumers’ Rate E-1 (which, as noted earlier, provides an annualized subsidy of $48.5 million) will expire as of November 30, 2015. This will, as noted by the company, “have the effect of decreasing the rates of primary, secondary, and residential customers who pay the subsidies,” while increasing the rates paid by its one Rate E-1 customer (e.g., Hemlock) who will then be transitioned into Consumers’ GPD Rate. Consumers’ reply brief, p. 20. As correctly pointed out by the utility, the expiration of this massive subsidy could thus be used to “neutralize” some of the impact of the cost allocation changes stemming from this proceeding. \textit{Id.}

Moreover, adopting the earlier implementation date suggested by ABATE could prove both burdensome to Consumers and confusing to its ratepayers. \textit{See, Id.} The reason for this is that:

\[\text{[I]t may cause the Company to implement four major rate changes in less than an eight month period. For instance, if new rates were implemented with the Commission’s final order in this case, the Company would need to: (i) implement new rates on July 3, 2015 with the final order in this case; (ii) implement new rates with the expiration of Rate E-1 on November 30, 2015; (iii) implement the rates ultimately approved by the Commission in the Company’s electric general rate case, Case No. U-17735, on December 5, 2015, and (iv) then implement another rate change to remove the O&M associated with the retirement of the Company’s “Classic 7 Coal Units” in approximately April 2016. The administrative burdens and}\]

U-17688
Page 126
potential customer confusion associated with a scenario like the one described above further illustrate the unreasonableness of ABATEs' proposal.

Id. Based on the reasons expressed above, the ALJ finds that ABATE's proposed effective date should be rejected, and that the Staff's should be adopted instead. As a result, the ALJ recommends that the Commission designate December 1, 2015, as the date upon which any rate and tariff changes resulting from this case would take effect.

V.

CONCLUSION

Based on the foregoing discussion, the ALJ recommends that the Commission issue an order adopting each of the findings and conclusions set forth above. Most importantly, it is recommended that the Commission: (1) reject Consumers' proposal to modify the existing 4CP 50/25/25 structure used to allocate production-related costs; (2) modify the current allocation of the utility's transportation costs to implement a 12CP 100/0/0 structure; (3) approve Consumers' proposed distribution cost allocation methodology, which relies on peak class demands at generation, including all electric demands related to its ROA customers; (4) generally retain the current methodology for allocating customer-related expenses, while also directing Consumers to assign UAE’s to all customers by way of the total cost of service method suggested by Energy Michigan; (5) make all rate design and tariff language changes recommended in Section IV(E) of this PFD; and (6) find that all rate and tariff changes arising from by the above-stated actions should take effect as of December 1, 2015
Finally, it should be noted that any arguments not specifically addressed in this PFD are either rejected or have been deemed irrelevant to the ALJ’s ultimate findings and conclusions expressed above.