STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter, on the Commission's own motion, to commence a collaborative to consider issues related to integrated resource and distribution plans.	))))	Case No. U-20633

COMMENTS OF THE
ASSOCIATION OF BUSINESSES ADVOCATING TARIFF EQUITY

I. INTRODUCTION

At the December 16, 2020 stakeholder session in this proceeding Commission Staff requested feedback regarding a variety of questions relating to forecasting, as set forth in greater detail below. As industrial distributed energy resources ("DER") (specifically demand response ("DR") and battery storage resources) have the potential to greatly increase and, in combination with residential adoption of additional DER, offset the need for traditional utility investment in distribution systems, forecasts must anticipate and include these resources. In line with this needed focus on considering and incorporating DER resources into various forecasts, ABATE's general comments are included below.

II. COMMENTS

A. Comments related to expert presentations.

Utilities ultimately remain motivated by their ability to earn a return on capital investments, which can lead to inflated growth expectations and a predilection for undervaluing and underestimating DER and other methods available to reduce load. (See e.g. Case No. U-20697, 5 Tr 983; 8 Tr 3826-27; Michigan Environmental Council's Initial Br at 152-54 (explaining that in the context of a conservation voltage reduction measure Consumers Energy Company's position was essentially "that the Company feels free to skew the IRP inputs within the range of

reasonableness in order to choose IRP inputs that are resource[s] on which the Company can earn a significant profit").) Despite utilities' focus on load growth and investments from which it can earn the greatest profit, however, increasing DER will continue to serve as an effective offset. Thus, concentrating on more centralized generation (and transmission) to address predicted load growth will likely lead to significant unnecessary stranded investment and unreasonably excessive customer costs.

As noted above, the potential for peak demand reduction through DR and battery technology continues to increase and reduce the load utilities must service through traditional investment. This load (kW) reduction by large industrial customers combined with the energy (kWh) reduction provided by residential adoption of DERs must therefore be considered when conducting load, capacity, and technology forecasts. Curt Volkmann's presentation at the December 16 stakeholder session regarding Distribution Forecasting addressed load and DER forecasting and the need for new approaches. The recommendations contained therein, including those for consideration in the utilities' next five-year distribution plans, provide good direction for considering and incorporating DER into forecasting. (See e.g. slide 35.)

B. Are there publicly available recommended sources that should be used for technology and fuel price forecasts? Are there other collaborative ways to develop technology and fuel price forecasts that could be used by all Michigan utilities filing an IRP?

Price forecasts for technologies can be difficult to develop, as are fuel price forecasts. That said, the U.S. Department of Energy's Energy Information Administration produces fuel price

forecasts which can be instructive,[1] while NREL is a good source for technology price forecasts (e.g. photovoltaic solar, storage, etc.).[2]

C. Are there publicly available recommended sources that should be used for capacity and energy price forecasts?

MISO offers some energy and load forecasts, although to convert these into energy and capacity price forecasts would require additional review and development.

III. CONCLUSION

Pursuant to Staff's solicitation of feedback ABATE recommends Staff incorporate consideration of the issues and points raised above into this stakeholder proceeding.

Respectfully submitted,

CLARK HILL PLC

By: Stephen A. Campbell

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Date: January 7, 2021

[1] https://www.eia.gov/analysis/projection-data.php#annualproj

[2] https://atb.nrel.gov

01/08/2021

Comments of Consumers Energy Company
in the Integration of Resource/Distribution/Transmission Planning Workgroup
Session Five Feedback Request

Dear Ms. Rogers,

Thank you for the opportunity to provide comments on the feedback that Staff solicited during the fifth Advanced Planning stakeholder workgroup.

The Company would like to share the following considerations on Staff's questions:

1) **Please provide any comments related to today's expert presentations.**
https://www.michigan.gov/documents/mpsc/Advanced_Planning_12-16-20_Presentation_710587_7.pdf

The Company has no specific comments on any of the December 16th presentations, but continues to appreciate hearing from different experts and viewpoints in this format.

2) **What is an appropriate growth rate to be used for a high load growth sensitivity? Should there be a different growth rate applied for high load with and without deep electrification? Should the rate be different for the lower peninsula and the upper peninsula? If so, what should they be?**

In the context of IRP modeling parameters for future utility IRPs, the Company finds these questions to be premature. It should be recognized that the development of a scenario must include a coherent view of underlining assumptions and causes creating the need for a sensitivity. The type and recommended forecasts to be used for a sensitivity such as this should be discussed at the time the Staff conducts their future discussion on IRP modeling parameters filed in 2023 and after. A source of information to use at this time for guidance are the 2021 MISO Transmission Expansion Plan (MTEP) Futures. These futures for the MISO region contain key assumptions and potential futures, which have been vetted by the Midcontinent Independent System Operator (MISO) and are representative of stakeholder input, including the service territories and zones applicable within the State of Michigan. The MTEP Futures program considers a variety of economic, political, and technological changes of different rates over time, including load growth rates. MTEP Futures currently

includes a potential future that has assumptions for high energy demand, as well as significant annual load growth rates.

While the above comments are focused on IRP planning, the Company would also like to comment with regards to distribution planning load growth, as distribution planning is within the scope of the Advanced Planning Workgroup where these questions were initiated. Current distribution planning load growth assumptions at the Company align with the load forecasts currently utilized in IRP and transmission planning, with the exception of those circuits that achieve peak load that is non-coincident with the system peak load (examples include circuits serving industrial customers which experience peak load in non-summer months, such as colleges and universities). In these cases, it is most appropriate for the utility to evaluate which of these types of customers exist in their service territory, and then utilize proper experience and judgement to develop customized load forecasts for these types of customers.

3) **What is an appropriate growth rate to be used for low load growth sensitivities? How should the low load growth sensitivity consider customer adoption of distributed energy resources? Should the rate be different for the lower peninsula and the upper peninsula? If so, what should they be?**

In the context of an IRP regarding the use of specific growth rates in sensitivity analysis, the Company recommends alignment with the MISO Transmission Expansion Plan (MTEP) Futures key assumptions and potential futures, which have been vetted by the Midcontinent Independent System Operator (MISO) and are representative of stakeholder input, including the service territories and zones applicable within the State of Michigan. As mentioned above, the MTEP Futures program considers a variety of economic, political, and technological changes of different rates over time, including a "low-base growth" future which is representative of a lower load growth rate over time, and lower overall energy demand. The Company reiterates the statements in response to item 2 that these discussions be held as part of the scenario development to be required for future utility IRP filings.

4) **Are there publicly available recommended sources that should be used for technology and fuel price forecasts? Are there other collaborative ways to develop technology and fuel price forecasts that could be used by all Michigan utilities filing an IRP?**

As stated previously in comments provided on November 25th, 2020 in response to Michigan Public Service Commission Staff ("Staff") Strawman Proposal for satisfying Executive Directive ("ED") 2020-10, the Company recommends a more flexible requirement for fuel price and technology forecasts. A flexible approach provides the opportunity for the utility and stakeholders to assess multiple business-as-usual forecasts offered by various industry sources to determine the most accurate forecasts. A less prescriptive approach, as opposed to requiring specific publicly available sources, provides greater agility to identify changing market and industry conditions that will then have an impact on long-term resource plans. Additionally, technology and fuel forecasts used within a scenario that is not a reference case the use of forecasts should be guided by the intent and purpose of that scenario. It is challenging to offer sources of forecasts without understanding the scenario it is to be used in.

With regards to collaborative ways to develop technology and fuel price forecasts, as previously stated in the November 25th comments, the Company believes collaboration through continued stakeholder engagement is a valuable avenue to obtain more frequent feedback and thinking into utility IRPs. This is a process the company has used in prior integrated resource planning and looks forward to continuing to expand on in future resource plans.

5) **Are there publicly available recommended sources that should be used for capacity and energy price forecasts?**

The Company does not recommend specific sources for capacity or energy price forecasts. The use of energy and capacity prices in integrated resource planning is very specific to an individual utility, and it is most appropriate for the utility to develop these types of forecasts. Like most, if not all, capacity expansion models, the energy price forecasts are an output of the computational models used for IRPs (i.e. Aurora)., The model is used to simulate the entire MISO Energy Market as a standard part of the IRP modeling process. It would not be appropriate to identify a base energy price forecast. s

With regards to capacity price forecasts, based on the current capacity position of a specific utility, the value of capacity could mean very different things to

different utilities, and therefore it is more appropriate that the Company develop its own capacity price forecasts that are associated with its current capacity position, as opposed to being required to use a specific forecast. Additionally, and of most importance, a capacity price forecast is not an input assumption to an IRP model. It is not used in the optimizations of the model. Therefore, it is not relevant for a capacity price forecast to be prescribed by the MPSC for utility IRPs.

Respectfully submitted,
Consumers Energy Company

DTE Electric Response to Staff Questions Requested 12-16-2020
MI Power Grid– Advanced Planning Phase II
January 8, 2021

Overall Comments:

DTE Electric (DTE or Company) appreciates the effort of Michigan Public Service Commission (MPSC), MPSC Staff (Staff) and all parties involved in this Integrated Planning collaborative. DTE will address each of the questions below.

1. Please provide any comments related to today's expert presentations.

   DTE does not have any comments on the presentations presented at the December 16th collaborative

2. What is an appropriate growth rate to be used for a high load growth sensitivities?
   a. Should there be a different growth rate applied for high load with and without deep electrification?
   b. Should the rate be different for the lower peninsula and the upper peninsula?
   c. If so, what should they be?

   DTE believes growth rate sensitivities applied to a utility's overall load are too prescriptive and will not provide true insight for analysis and planning purposes. Simply applying a growth rate to sales assumes that the historical relationship between sales and peak demand will stay constant. This is not the case. While higher energy sales growth will likely result from increased electrification, these new sources of energy do not share the same peak profile as historical sales do. For example, heating electrification will peak in winter months which will have no impact on the system peak that occurs in the summer. Also, typically electric vehicle charging peaks in the evening after system peak has occurred.

   In order to gain more accurate insight and analysis for planning purposes, load sensitivities should focus on specific growth scenarios associated with emerging technologies tied to electrification, such as EV adoption, appliance electrification adoption and/or adoption of distributed energy resources. Representative load shapes for each of the technologies should be used to determine the appropriate impact on system peak. Breaking these adoption rates into scenarios such as low or high could provide enough differentiation and insight to provide meaningful analysis and implications for sales and peak loads.

   DTE believes load growth sensitivities should be developed by each utility and be specific to that respective utility's service territory. Market dynamics and economic conditions are significantly different across the state of Michigan, as well as over time, and the technologies mentioned above could see vastly different adoption rates for each utility.

3. What is an appropriate growth rate to be used for low load growth sensitivities?
   a. How should the low load growth sensitivity consider customer adoption of distributed energy resources?
   b. Should the rate be different for the lower peninsula and the upper peninsula?
   c. If so, what should they be?

   See response to question #2.

4. Are there publicly available recommended sources that should be used for technology and fuel price forecasts?

The listed sources in the MIRPP modeling requirements, (U-18418, issued 11-21-2017 pages 24-25) including EIA, NREL, and Lazard, are still valid sources for technology costs. Each utility should continue to use the most recent version, as practical, of these sources in their modeling and/or use their discretion to select other sources that are reflective of current technology and fuel prices. For natural gas prices, DTE recommends allowing more flexibility than requiring the EIA Annual Energy Outlook due to concerns that the assumptions underlying the EIA forecast may be misaligned with the assumptions specified in the MIRPP scenarios.

   a. Are there other collaborative ways to develop technology and fuel price forecasts that could be used by all Michigan utilities filing an IRP?

Due to the varied filing dates from each utility, the Company cannot propose a simplified approach to develop common assumptions to be used in all IRPs without the assumptions quickly becoming obsolete.

5. Are there publicly available recommended sources that should be used for capacity and energy price forecasts?

No, there are no recommended sources for publicly available energy prices. The three required scenarios are very specific and require energy prices to be developed in concert with technology costs, fuel prices assumptions, environmental assumptions, and Michigan fleet retirement and addition assumptions. These specified scenario inputs drive the resulting energy prices and must stay aligned, otherwise non-sensical modeling could result. There are no publicly available sources for energy prices for 15-20 years that incorporate the specific requirements of the MIRPP.

For capacity prices, MISO publishes a cost of new entry (CONE) calculation for the upcoming capacity planning year. The CONE price is usually indicative of a high-end capacity price. DTE is not aware of any other publicly available capacity price forecasts. DTE does not support predetermining or prescribing that the same capacity price be specified for all utilities. The value of capacity will be different for each utility and will vary by the utility's specific forecasted capacity position each year.

Indiana Michigan Power
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January 8, 2020

To: Danielle Rogers by, Michigan Public Service Commission

Re: **Integration of Resource/Distribution/Transmission Planning**

Indiana Michigan Power Company (I&M or Company) submits these comments in response to the Michigan Public Service Commission Staff's questions arising from the December 16, 2020 workshop. I&M appreciates this opportunity to comment.

1. Please provide any comments related to today's expert presentations.

I&M Response: I&M appreciates Staff's time and efforts to coordinate speakers and presentations for this and all workshops conducted.

2. What is an appropriate growth rate to be used for a high load growth sensitivities? Should there be a different growth rate applied for high load with and without deep electrification? Should the rate be different for the lower peninsula and the upper peninsula? If so, what should they be?

I&M Response: I&M's current base forecast is assuming an average decline of 0.5% per year beyond 2030. The high load scenario assumes an average growth of 0.6% through 2030 and an average of 0.9% per year beyond 2030, or 1.1% to 1.4% above the base forecast. I&M does not support modeling a load growth rate target of 1% or more as that would be unrealistic and not supported by the customer composition of I&M's load profile. The issue with assuming a different growth rate for 'deep electrification' is that there is an offsetting drag on I&M's load growth as a result of the lost economic impact of industries that support the fossil fuel industries. At some point, the growth from electrification begins to be offset by the decline in jobs, economic output, etc.

3. What is an appropriate growth rate to be used for low load growth sensitivities? How should the low load growth sensitivity consider customer adoption of distributed energy resources? Should the rate be different for the lower peninsula and the upper peninsula? If so, what should they be?

I&M Response: I&M's current long-term low load scenario assumes an average decline of 1.4% per year, or .9% below the base forecast. The low load scenario is largely driven by Energy Information Administration's (EIA) low economic growth assumptions. Under those assumptions (that the economy is more challenged than under the base forecast), it would not

make sense to assume higher levels of DG given the empirical studies that suggest customer adoption of DG is influenced by higher incomes.

4. Are there publically available recommended sources that should be used for technology and fuel price forecasts? Are there other collaborative ways to develop technology and fuel price forecast that could be used by all Michigan utilities filing an IRP?

I&M Response: The EIA Annual Energy Outlook is publically available and a common reference for fuel price forecasts and technology assumptions. I&M, as a multi-jurisdictional utility and member of PJM, does not support using a Michigan only technology and fuel price forecast for IRP development. In addition, this type of undertaking removes strategic knowledge and utility management assumptions.

5. Are there publically available recommended sources that should be used for capacity and energy price forecasts?

I&M Response: No. EIA does not provide wholesale energy or capacity prices. PJM publishes short-term (4-year) capacity prices resulting from their Base Residual Auction, which was recently reinstated.

Ms. Danielle Rogers
Michigan Public Service Commission
7109 W. Saginaw Hwy.
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January 8, 2021

Re: MPSC Staff Request for Feedback following December 16, 2020 Stakeholder Session in Integration of Resource/Distribution/Transmission Planning Working Group

Ms. Rogers,

On December 16, 2020, the Integration of Resource/Distribution/Transmission Planning workgroup held its fifth stakeholder session. At the conclusion of that session, the Staff of the Michigan Public Service Commission requested feedback related to the expert presentations made during that workshop. The Environmental Law & Policy Center, the Natural Resources Defense Council, Vote Solar, the Union of Concerned Scientists, and the Ecology Center (Joint Commenters) respond to Staff's request for feedback below.

Comments Related to Dec. 16 '20 Expert Presentations on Forecasting

The thrust of the December 16, 2020 workshop was that forecasting underpins several system planning processes, that mis-forecasting leads to increased costs, and that robust forecasting that accurately accounts for distribution-connected resources (including load, generation, load modifying, and load shifting resources) is critical. The December 16 workshop also made clear that forecasting practices must evolve to keep up with new dynamics on the distribution system—including but not limited to DER deployment, increasing electrification, and changing load patterns. Joint Commenters agree, and note that the Commission's Phase I Advanced Planning process included similar expert presentations that emphasized the importance of advanced dynamic system load forecasting (in particular during the June 27, 2019 stakeholder session in U-20147).

One of the objectives of this Phase II stakeholder process is to consider potential improvements to distributed energy resource (DER – including energy efficiency and demand response), electric vehicle (EV) and load forecasting practices in Michigan, and, importantly, to incorporate those improvements into the utilities' resource and distribution plan filings going forward. As described in the presenters' remarks and

materials, DER, including energy efficiency and demand response, need to be considered across utility planning processes in order to more efficiently plan and operate the system. In furtherance of that objective, and based in part on the material covered in the expert presentations featured in the December 16, 2020 workshop, Joint Commenters offer the following comments and recommendations:

- *Start by getting a clear picture of utilities' current forecasting capabilities and planned improvements to forecasting capabilities*.

Based on the utilities' previous distribution plan filings and recent rate case filings, stakeholders have an incomplete picture of the utilities' current load, DER and EV forecasting capabilities, the granularity of those capabilities, and planned improvements to those capabilities. Without a baseline understanding of capabilities, it is difficult for stakeholders to evaluate the necessary improvements to forecasting practices in either distribution or resource plans. Joint Commenters recommend that the Staff ask the utilities to provide the information described in slide 35 of the December 16 workshop presentation (from the presentation of Mr. Volkmann) as a part of their 2021 distribution plan filings, and reproduced below:

Forecast Accuracy: Circuit and planning area forecast vs. actual 2016-2020 Actions to improve accuracy
Load Forecasting: Current and planned spatial and temporal granularity? Scenarios? Loading criteria? Current tools, planned investment in new tools? Minimum loads known? COVID-19 impacts? Electrification impacts? Ex post assessments? Alignment with IRP? Stakeholder engagement?
DER Forecasting Methodologies? Scenarios? Compared with third-party forecasts? Incorporated in load forecasts? DER connectivity known? Alignment with DER forecasts in IRP? Stakeholder engagement?

- *Integrate AMI data into forecasts.*

In the recently concluded Consumers Energy rate case, the Commission recognized that advanced metering infrastructure data can help improve load forecasts, and agreed that future load forecasts should be based on AMI data and other data such as Consumers' hosting capacity analysis and its interconnection process (U-20697 Order at 60). Currently, our understanding is that neither DTE nor I&M use AMI data in their load forecasts. Joint Commenters recommend that the utilities each explain, in their forthcoming plan filings, how they plan on incorporating AMI data into their load forecasting practices, and recommend that Staff specifically ask that the utilities do so through their final report in this proceeding.

- *Investigate industry-leading advanced forecasting tools.*

The expert presenters in the December 16 workshop described a variety of new analytical tools that include more powerful and granular load and DER (and EV) forecasting capabilities, including LoadSEER and dGEN. These advanced planning tools can serve as a backbone for several integrated grid planning activities, including non-wires alternatives analysis and DER valuation. While Joint Commenters do not recommend a particular forecasting tool at this time, we believe it would be valuable for the MPSC Staff to further investigate industry-leading advanced distribution planning tools in a future stakeholder workshop.

<u>Comments related to Alignment between IRPs and 5 Year Distribution Plans</u>

Several presenters, notably Curt Volkmann and Brady Cowistell, noted that mis-forecasting leads to higher costs. Specifically, this can result in an over-built or under-built system- be it transmission, distribution, or generation. As customer load profiles change in response to the on-going COVID pandemic, growth of DER, and electrification efforts, it will be increasingly important that utilities better integrate load forecasts with distribution planning activities and IRP – and improve consistency across both efforts - to ensure that Michigan's electricity system is meeting the needs of its customers.

As Michigan's utilities continue preparation for their next 5 year distribution plan filings, clear guidance is needed from the Commission to ensure that the forecasts used in those plans appropriately capture the uses, roles, and opportunities for DER to be used as solutions and not simply as reductions in demand. Relatedly, in the IRP process, whereas traditional capacity expansion modeling treats DER as an exogenous variable, resource planning should treat DER as a resource that can be activated.

Furthermore, utilities should acknowledge and value the transmission and distribution system benefits of DER when evaluating resources.

The future of forecasting must reflect the changes occurring on the distribution system and start taking into account more bottom-up analyses based on customers' actual decisions. If forecasting methodologies are not consistent across the planning efforts, especially for the 5 year distribution planning effort, then Michigan runs the risk of investing in the wrong technology, locating it in the wrong place, and at the wrong time- and customers will pay for each of those bad outcomes.

Comments related to Dec. 16 '20 Expert Presentations on DER Valuation

The presentation by Tom Eckman of Lawrence Berkley National Laboratory provided an important perspective. The framework Mr. Eckman described for identifying and valuing the full scope of benefits that flexible demand presents is applicable not only to an analysis of flexible buildings, but extends also to DER valuation across a range of other utility planning efforts and Commission proceedings.

Mr. Eckman illustrated how DER benefits cross traditional utility planning silos and can thus be undervalued. He proposed seven considerations for enhanced valuation methods:

1. Account for all electric utility system economic impacts resulting from demand flexibility
2. Account for variations in value based on when demand flexibility occurs
3. Account for the impact of distribution system savings on transmission and generation system value
4. Account for variations in value specific location on the grid
5. Account for variations in value due to interactions between DERs providing demand flexibility
6. Account for benefits across the full expected useful lives (EULs) of the resources
7. Account for variations in value due to interactions between DERs and other system resources

Joint Commenters would point out that the Commission's December 17 Order in the recent Consumers Energy rate case, U-20697, established a stakeholder group and study process to study distributed energy resources. Specifically, as amended by a December 30 Errata, ordering paragraph K directs:

> ""In the first quarter of 2021, the Commission Staff shall initiate a work group to examine the costs and benefits of distributed energy resources, including solar, in the context of how customers use the grid now and in the future, as described in this order."

This DER cost and benefits study will be an important opportunity for the Commission to implement the enhanced valuation methods as described by Eckman. In addition, the guidance for distribution, transmission and resource planning that flow from this Advanced Planning proceeding should encourage further exploration of DER valuation.

Conclusion

Joint Commenters appreciate this opportunity to provide feedback and look forward to engaging in the next stakeholder workshop in this Advanced Planning workgroup.

From: Robert Stegmier
To: Rogers, Danielle (LARA)
Subject: MI Power Grid Advanced Planning Processes workshops, MY COMMENTS!
Date: Monday, January 4, 2021 3:03:40 PM

Thank you for your interest in the MI Power Grid Advanced Planning Processes workgroups.
The fifth virtual stakeholder session for the Integration of Resource/Distribution/Transmission Planning Workgroup was held on Wednesday, December 16 (meeting recording). During this session, Staff requested stakeholder feedback on several forecasting questions contained at the end of the presentation. Please email your feedback to Danielle Rogers at rogersd8@michigan.gov by **5:00 p.m. on January 8, 2021**.Da

Danielle Rogers; my comments regarding the 12, 16, 2020 meeting mentioned above:

My input is largely from my position as a Consumers Energy customer with a 2 Kw solar voltaic system installed on my home roof 11 years ago. It is based on 11 years of investigating solar and experiencing distributed energy as I see it and as CE seems to see it now. Of course "Climate Change" an extremely serious situation is in the forefront with it all now!

My conclusion is CE, DTE and Great Lakes Energy as controlled monopolies and those charged with orchestrating the power shift from fossil fuels to non polluting green house gas electricity are prone to move too slow. Too slow for various reasons, they are monopolies, legislators and control boards. To me a cumbersome group. What isn't cumbersome is climate change and certainly the competitive automobile industry. The auto industry is free enterprise maybe at its best with flexibility and worldwide competition. This auto industry is well on its way to becoming all electric vehicles with a projection that 50 percent of the vehicles on the road being electric by 2035-36 and the internal combustion engine fast becoming obsolete. I am confident this will happen!
I believe there is an "all hands on deck" situation facing mankind and we must act accordingly.
I believe distributed energy and rooftop energy is a significant and important part of that "all hands on deck" what needs to happen.

In reference to Consumers Energy Rate Case (U-20697) Order from the MPSC issued on 12-17-2020.
Again I stress the need for distributed consumer energy fed to the grid. I understand the outflow rate talked about or approved for C.E. is 8 cent per kWh. I believe the rate is what I understand would be an average rate. I believe much of the solar distrusted energy would be fed to the grid at peak or near peak energy cost times of the energy companies. I believe 8 cents for the energy is too low! I had the privilege to see one recent CE billing which I understand was at what I understand is "time of day rates". The rates were, the Summer On Peak Energy

charge was $0.123494 per kWh and the Summer Off peak Energy charge was $0.084824 per kWh. Fair is fair and I firmly believe these are the current rates CE should pay to me or anyone feeding solar produced energy into the grid. After all, I have a 2 Kw solar system on my home roof. I made the investment and maintain the system for my solar panels and the necessary setup for converting the solar DC current into AC for feeding into the grid. I had storm damage a few years ago which was repaired at my expense. Much like what the electric provider does with lines and equipment. Also some of my power produced is excess and sent to the CE grid at close to peak or at peak and as I see it CE delivers my excess a short distance to my next door neighbor and collects from that neighbor their full rate plus a "distribution charge" on it. I believe this "distribution" charge is an over charge or simply a bonus for CE because of the very short distance covered in its delivery. If I see this wrong, please let me know why! I believe it is "past time" for CE, the State of Michigan Legislators and the MPSC too to fully embrace S.V. distributed energy production from customers. I believe in the basic American idea of individual freedoms! I further believe that a liberal amount over the customers annual usage should be allowed to be feed back into the grid. In my opinion the increase of allowed excess power fed to the grid from 1% to 2% is totally inadequate. I suggest something like 5 % to 10% to be more appropriate! Such liberalization will accelerate efforts in helping the world in rapidly becoming carbon neutral! Something sorely needed with an "all hands on deck" effort in the fight against "climate change". Hopefully before 2050 an important recognized "carbon neutral" target date.

I have done some research and found this bit of information from a friend in New Britain Township about 20 miles directly north of Philadelphia. The Post Office city name is Chalfont. These are his words. ***"Here is a good plan from my local power company PECO concerning net metering. Note that they not only encourage net metering but if you have an excess they will pay you back at the current full retail rate that they charge. There is also no limit on how much you can return to the grid. They also provide a $400 incentive to install the second meter needed to measure returned energy. They also provide a lower rate from the beginning of October until the end of May for the distribution part of the bill if you use a heat pump for your heating. I am on that rate with the distribution charge being $.048/kWh."***

In conclusion, I will send the message to my Governor, and state legislators FTI and considerations.

Robert Stegmier

Rockford MI 49341