

**PURPA Technical
Advisory Committee**

**Report on the Continued
Appropriateness of the
Commission's Implementation of
PURPA**

**PREPARED BY:
MICHIGAN PUBLIC SERVICE COMMISSION STAFF**

MPSC Case No. U-17973

April 8, 2016

On October 27, 2015, the Michigan Public Service Commission (Commission) directed the Electric Reliability Division to form a Technical Advisory Committee to consider the Public Utility Regulatory Policies Act of 1978, Pub L No. 95-617, 92 Stat 3117 (PURPA).

The Director of the Commission's Electric Reliability Division is directed to commence the process of forming a Technical Advisory Committee to assess the continuing appropriateness of the Commission's current regulatory implementation regarding the Public Utility Regulatory Policies Act of 1978, and to report its findings and recommendations to the Commission by filing a report in this docket no later than April 8, 2016.

MPSC Case No. U-17973, [Order](#) issued on October 27, 2015

PURPA Technical Advisory Committee (PURPA TAC) participants provided a wide range of backgrounds and perspectives. Participation was welcomed from all who volunteered and included utilities, environmental groups, current and potential future qualifying facilities (QF), industry PURPA experts and MPSC Staff.

The PURPA TAC met five times at MPSC offices from December 2015 to March 2016. Agendas, presentations and related documents recommended by PURPA TAC participants are posted on the [MPSC's PURPA TAC website](#).

PURPA TAC goals were discussed at the first meeting on December 8, 2015:

- Develop an on-going, routine Commission administrative process for determining avoided cost for 20 MW and smaller PURPA projects
- Research avoided cost methodologies
- Present recommendations for each of the above tasks in the PURPA TAC report
- If there is not consensus, each recommendation will be included in the PURPA TAC report

There was general consensus within the group regarding the goals. Summaries of the five in-person meetings are included in *Appendix A*.

MPSC PURPA Implementation – 1978 to the Present

In MPSC Case No. U-6798, the Commission initiated proceedings on March 17, 1981 (Initial Order) to implement the provisions of Section 210 of PURPA (16 USC 824a-3). Five additional orders were issued under the U-6798 docket. In the Initial Order, the Commission identified the following state regulatory authority obligations under PURPA and the federal regulations implementing it:

- File a report with FERC describing implementation
- Set avoided cost rates
- Set a standard rate for QFs of 100 kW or less
- Set rates for standby service
- Address interconnection costs
- Establish a procedure for handling complaints

The utility obligations are described below:

- Purchase at avoided cost
- Provide standby service
- Provide interconnections to QF
- File data

The Initial Order established interim rates for both purchased and standby power and required utilities to offer interconnections to QFs. A contested case process provided an in-depth review of PURPA implementation which culminated in an Order issued on August 27, 1982. The August 27, 1982 Order approved a series of settlement agreements with varying avoided cost methodologies and directed utilities to file tariffs with the Commission and make their assumptions, data and the calculation methodology available to the public upon request.

A significant case related to Consumers Energy Company's (Consumers Energy) avoided cost determination involved a PURPA contract between the Midland Cogeneration Venture and Consumers Energy, MPSC Case No. U-8871. The Commission consolidated more than 40 cases to undertake a comprehensive proceeding to consider this contract and many others. The case included a series of 20 Orders from 1987 – 1993 and resulted in many QF contracts with rates based on a proxy coal plant's avoided cost.

Act 81 of 1987 (MCL 460.6j, as amended) was enacted to address capacity payments for PURPA contracts among other things.¹

Act 81 says in part:

(b) Disallow any capacity charges associated with power purchased for periods in excess of 6 months unless the utility has obtained the prior approval of the commission. If the commission has approved capacity charges in a contract with a qualifying facility, as defined by the federal energy regulatory commission pursuant to the public utilities regulatory policies act of 1978, Public Law 95-617, 92 Stat. 3117, the commission shall not disallow the capacity charges for the facility in the power supply cost reconciliation unless the commission has ordered revised capacity charges upon reconsideration pursuant to this subsection. A contract shall be valid and binding in accordance with its terms and capacity charges paid pursuant to such a contract shall be recoverable costs of the utility for rate-making purposes notwithstanding that the order approving such a contract is later vacated, modified, or otherwise held to be invalid in whole or in part if the order approving the contract has not been stayed or suspended by a competent court within 30 days after the date of the order, or within 30 days of the effective date of the 1987 amendatory act that added subsection (19) if the order was issued after September 1, 1986, and before the effective date of the 1987 amendatory act that added subsection (19). The scope and manner of the review of capacity charges for a qualifying facility shall be determined

¹ Act 81 amended Act 304 of 1982, which established power supply cost recovery proceedings and incorporated these proceedings into Act 3 of 1939 (MPSC Act).

by the commission. Except as to approvals for qualifying facilities granted by the commission prior to June 1, 1987, proceedings before the commission seeking such approvals shall be conducted as a contested case pursuant to chapter 4 of the administrative procedures act of 1969, Act No. 306 of the Public Acts of 1969. The commission, upon its own motion or upon application of any person, may reconsider its approval of capacity charges in a contested case hearing after passage of a period necessary for financing the qualifying facility, provided that:

- (i) The commission has first issued an order making a finding based on evidence presented in a contested case that there has been a substantial change in circumstances since the commission's initial approval; and
- (ii) Such a commission finding shall be set forth in a commission order subject to immediate judicial review.

The financing period for a qualifying facility during which previously approved capacity charges shall not be subject to commission reconsideration shall be 17.5 years, beginning with the date of commercial operation, for all qualifying facilities, except that the minimum financing period before reconsideration of the previously approved capacity charges shall be for the duration of the financing for a qualifying facility which produces electric energy by the use of biomass, waste, wood, hydroelectric, wind, and other renewable resources, or any combination of renewable resources, as the primary energy source. [MCL 460.6j(13)(b).]

Act 2 of 1989 (MCL 460.6o, as amended) was enacted to address utility purchases from certain landfill gas and solid waste QFs.

Act 2 says in part:

(2) Public utilities with more than 500,000 customers in this state shall enter into power purchase agreements for the purchase of capacity and energy from resource recovery facilities that incinerate qualified landfill gas; that incinerate qualified solid waste, at least 50.1% of which is generated within the service areas of the public utility; or, subject to the provisions of this section, that incinerate scrap tires, under rates, charges, terms, and conditions of service that, for these facilities, may differ from those negotiated, authorized, or prescribed for purchases from qualifying facilities that are not resource recovery facilities. If a resource recovery facility incinerates scrap tires, or any other tires that are obtained from outside the state, or if more than 50.1% of the scrap tires or other tires are obtained outside the public utility service area, the public utility may in partial satisfaction of its obligation under this subsection purchase capacity and energy from the facility but is not obligated by this act to purchase the facility's capacity and energy. A resource recovery facility that incinerates at least 90% of its total annual fuel input in the form of scrap tires shall accept all scrap tires that first became scrap tires in the state and that are delivered to the facility by a scrap tire processor or a scrap tire hauler. The first 6,000,000 of these scrap tires delivered to the resource recovery facility each

year shall be charged a rate not greater than an amount equal to \$34.50 per ton, increased each calendar quarter beginning July 1, 1990, by an amount equal to the increase in the all items version of the consumer price index for urban wage earners and clerical workers during the prior calendar quarter. Including power purchase agreements executed prior to June 30, 1989, this section does not apply after 120 megawatts of electric resource recovery facility capacity in a utility's service territory have been contracted and entered in commercial operation. Additionally, this section does not apply to more than the first 30 megawatts of scrap tire fueled resource recovery facility capacity in the state that has been contracted and entered in commercial operation. Excluding rate provisions, if 1 or more provisions of a purchase agreement remain in dispute, each party shall submit to the commission all of the purchase agreement provisions of their last best offer and a supporting brief. On each disputed provision, the commission shall within 60 days either select or reject with recommendation the offers submitted by either party.

(3) A power purchase agreement entered into by a public utility for the purchase of capacity and energy from a resource recovery facility shall be filed with the commission and a contested case proceeding shall commence immediately pursuant to chapter 4 of the administrative procedures act of 1969, Act No. 306 of the Public Acts of 1969, being sections 24.271 to 24.287 of the Michigan Compiled Laws. Notwithstanding section 6j, a power purchase agreement shall be considered approved if the commission does not approve or disapprove the agreement within 6 months of the date of the filing of the agreement. Approval pursuant to this subsection constitutes prior approval under section 6j(13)(b).

(4) The energy rate component of all power sales contracts for resource recovery facilities shall be equal to the avoided energy cost of the purchasing utility.

(5) When averaged over the term of the contract, the capacity rate component of all power sales contracts for resource recovery facilities may be equal to but not less than the full avoided cost of the utility as determined by the commission. In determining the capacity rate, the commission may assume that the utility needs capacity.

(6) Capacity purchased by a utility prior to January 1, 2000 under a power sales contract with a resource recovery facility shall not be considered directly or indirectly in determining the utility's reserve margin, reserve capacity, or other resource capability measurement. To insure compliance with this act, a resource recovery facility that incinerates scrap tires shall provide an annual accounting to the legislature and the commission. The annual accounting shall include the total amount of scrap tires incinerated at the resource recovery facility and the percentage of those scrap tires that prior to incineration were used within this state for their original intended purpose. [MCL 460.6o(2-6).]

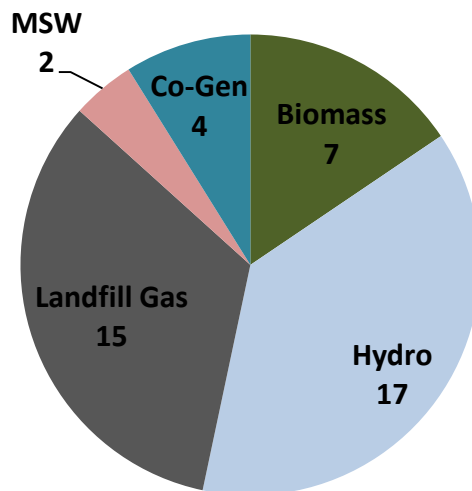
A number of PURPA contracts were executed and approved by the Commission either ex parte or as part of a contested case.

The Energy Policy Act of 2005 (PL 109-58; 119 Stat 594) allowed utilities to terminate mandatory purchase obligations if QFs have non-discriminatory access to competitive markets. DTE Electric Company (DTE Electric) was relieved, on a service territory basis, of the mandatory purchase obligation requirement to enter into new purchase obligations for QFs with a net capacity greater than 20 MW effective October 26, 2009.² FERC granted a similar request to Consumers Energy effective January 25, 2012.³ Since there is no purchase obligation for larger projects, PURPA TAC focused its efforts on 20 MW and smaller QFs.

As a result of some existing PURPA contracts expiring and potential new QFs inquiring about avoided cost rates and other factors, the Commission issued its October 27, 2015 Order establishing the PURPA TAC.

PURPA contracts currently in effect for Consumers Energy and DTE Electric are listed in *Appendix B*. There are currently 45 contracts with expiration dates ranging from May 2017 to 2039.⁴ **Figure 1** depicts the number of contracts by technology type. **Figure 2** shows the breakdown of QFs by technology type. PURPA contract capacity ranges from 80 kW (Michiana Hydro – Bellevue) to 1,240 MW (Midland Cogeneration Venture Limited Partnership - Cogen).

Figure 1: PURPA Contracts by Technology Type (45 Contracts in Total) Consumers Energy & DTE Electric

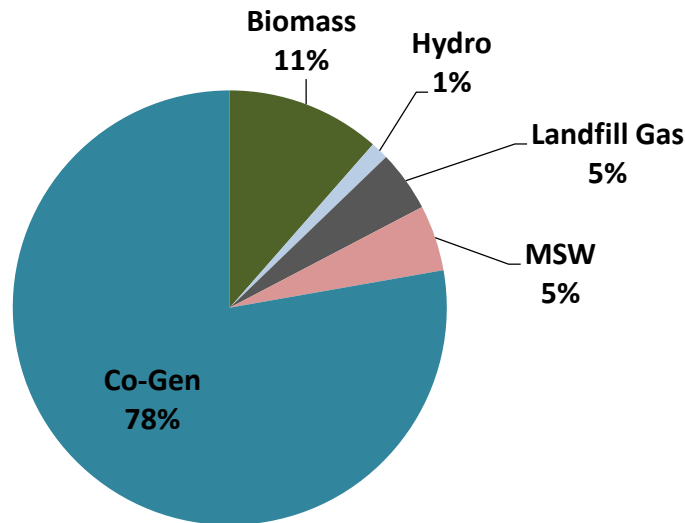


² <https://www.ferc.gov/whats-new/comm-meet/2010/041510/E-12.pdf>

³ <http://www.ferc.gov/EventCalendar/Files/20120424160511-QM12-3-000.pdf>

⁴ Consumers Energy filed an application on January 27, 2016 requesting approval of amendments to continue contracts with Hillman Power Company, L.L.C., Thornapple Association, Inc. and White’s Bridge Hydro Company under existing terms through May 31, 2017.

Figure 2: PURPA Contract Capacity (MW) by Technology Type (1,794 MW in Total) Consumers Energy & DTE Electric



Appendix B lists details about each contract and shows the structure of payments for the Consumers Energy PURPA contracts. Most of the contracts have separate payments for energy and capacity. For the majority of its contracts, the energy payment is based on Consumers Energy’s twelve-month rolling average cost of coal generation. The capacity payment is typically broken down into on- and off-peak time periods to recognize the added value of on-peak generation.

Proposed MPSC PURPA Administrative Process

The Commission’s avoided cost methodology based on a proxy coal plant (in general) has been in place for several decades. One of the goals of the PURPA TAC was to develop a process for the Commission to consider when updating this methodology. Staff presented its administrative process strawman at the January 13, 2016 meeting and a revised proposal at the February 10, 2016 meeting. The revisions incorporated both written comments and discussions from the PURPA TAC meetings.

Staff recommends that modifying the overall avoided cost methodology can be accomplished through an initial process focusing on the methodology. This process will likely be a one-time event unless there is a compelling reason for revising the avoided cost calculation methodology. Section 292.302 of the federal regulations implementing PURPA, entitled “Availability of Electric Utility System Cost Data,” requires utilities to file avoided cost data with the state regulatory authority every two years. 18 CFR 292.302(b).

Going forward, a biennial process that is aligned with the utility data reporting requirements could be used to refresh the avoided cost calculation.⁵

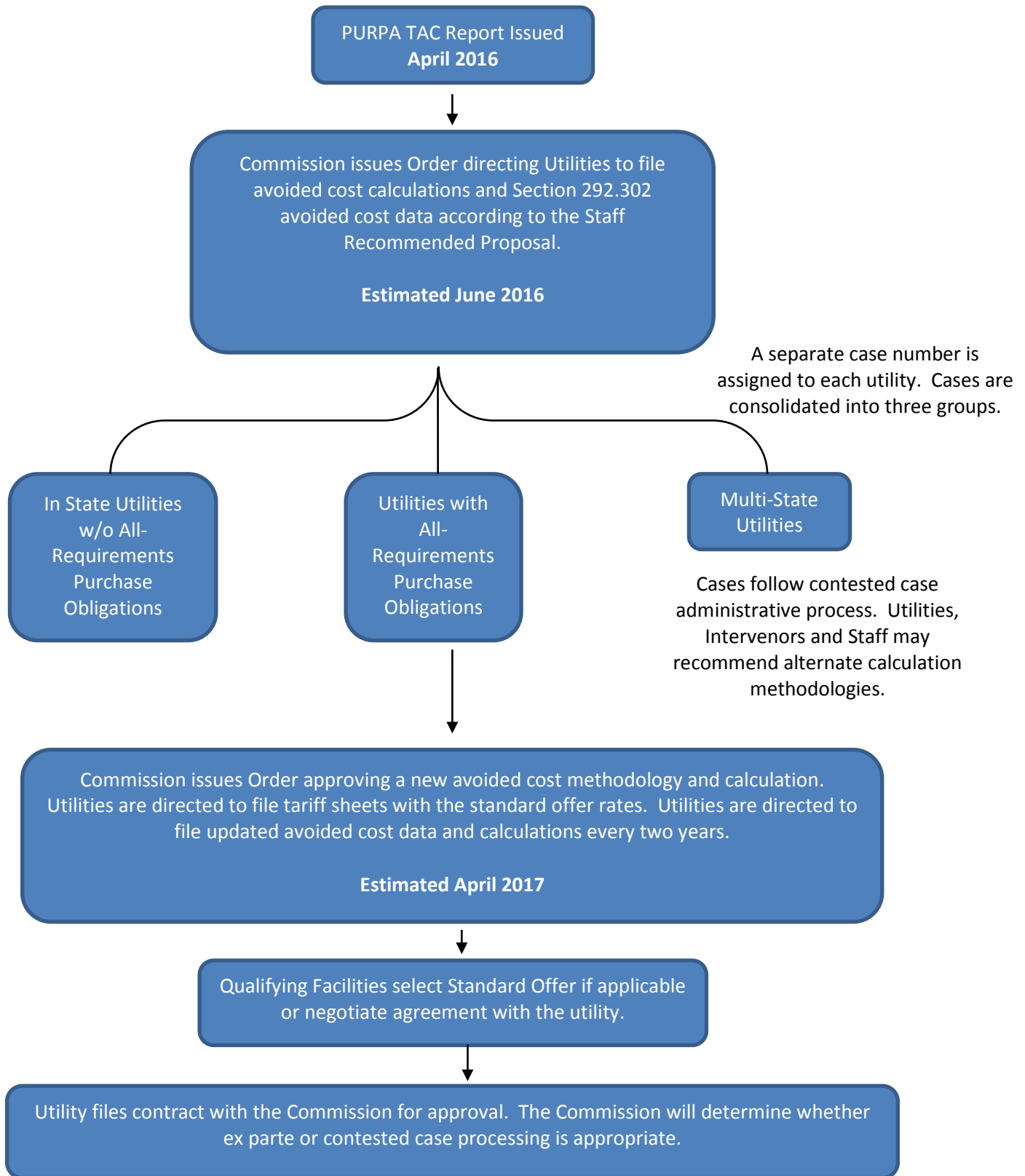
Figure 3 shows the Staff’s Proposed Administrative Process for Establishing a New Avoided Cost Calculation Methodology. The Staff’s proposed process assumes a full contested case proceeding to determine the methodology and allows an opportunity for all parties to provide expert testimony about avoided cost calculation methodologies and inputs. If the parties were to reach a settlement agreement at any time during the process, the timing to obtain a Commission order could be shortened.

During PURPA TAC discussions, QFs and potential QFs were concerned that having separate docketed cases for each utility would create unnecessary expense by requiring them to participate in separate proceedings. While there was general agreement by the PURPA TAC that the highest level of efficiency would be achieved by consolidating the cases into a single proceeding, Staff is concerned that a single proceeding could be unwieldy. Staff recommends consolidating the cases into three groups to provide consistency for similarly situated utilities, provide a means to group the cases between administrative law judges (ALJ) and limit the number of separate proceedings in which QFs participate. Some utilities have “all-requirements” purchase contracts with a supplier who provides all of the electricity that is provided to retail customers.⁶ According to PURPA, the avoided cost for these utilities would be based on the utility’s all-requirements contract with their supplier. Utilities who serve only customers located in-state without all-requirements purchase obligations are likely to have similar avoided cost methodologies. For multi-state utilities, the Commission may choose to consider the avoided cost methodology established by other jurisdictions. Member-regulated cooperatives will have their avoided cost determined by their governing boards and Staff has not included them as a utility type here.

⁵ http://www.michigan.gov/documents/mpsc/PURPA_MPSC_Strawman_-_AC_Administrative_Process_509173_7.pdf

⁶ All Requirements Contract - An agreement between an energy supplier and a utility in which the utility acquires all of its energy from a single source.

Figure 3: Staff Recommendation – Administrative Process for Establishing a New Avoided Cost Calculation Methodology



There was significant discussion around whether each PURPA contract required Commission approval through a contested case process. Staff initially recommended contested case approval as part of a power supply cost recovery (PSCR) case. For administrative efficiency, Consumers Energy preferred an ex parte approval process that is outside of the PSCR process. Consumers Energy pointed out that waiting for a PSCR order could add significant time to the PURPA contract approval process. Staff revised its proposal so that PURPA contracts would be approved separately from the PSCR process. Several QFs expressed concern with the legality and binding nature of approving these contracts outside of a contested case process. During the PURPA TAC meeting discussions, several participants involved with developing QFs in the past mentioned that they had experience with financing banks wanting the PURPA contract approved in a contested case instead of ex parte approval.

The PURPA TAC discussion centered around whether the Commission could approve the capacity charges as part of the overall avoided cost methodology in a contested case and then any contracts incorporating the previously approved capacity charges could be approved on an ex parte basis. Approving each PURPA contract in a contested case process requires the utility to meet MPSC case noticing requirements and for the Commission to have a hearing with an ALJ and lawyers representing the parties. A contested case is also an opportunity for intervenors to participate, which could lead to an extended approval period. If an ex parte approval were used, the utility would file the application requesting approval of the PURPA contract and the Commission would review the filing and issue an order without a contested hearing. There are significant administrative and timing efficiencies if an ex parte process is used.

The PURPA TAC discussed the meaning of the Act 81 language addressing Commission approval of contracts with capacity payments for periods in excess of six months.

Act 81 says in part:

(b) Disallow any capacity charges associated with power purchased for periods in excess of 6 months unless the utility has obtained the prior approval of the commission. If the commission has approved capacity charges in a contract with a qualifying facility, as defined by the federal energy regulatory commission pursuant to the public utilities regulatory policies act of 1978, Public Law 95-617, 92 Stat. 3117, the commission shall not disallow the capacity charges for the facility in the power supply cost reconciliation unless the commission has ordered revised capacity charges upon reconsideration pursuant to this subsection.

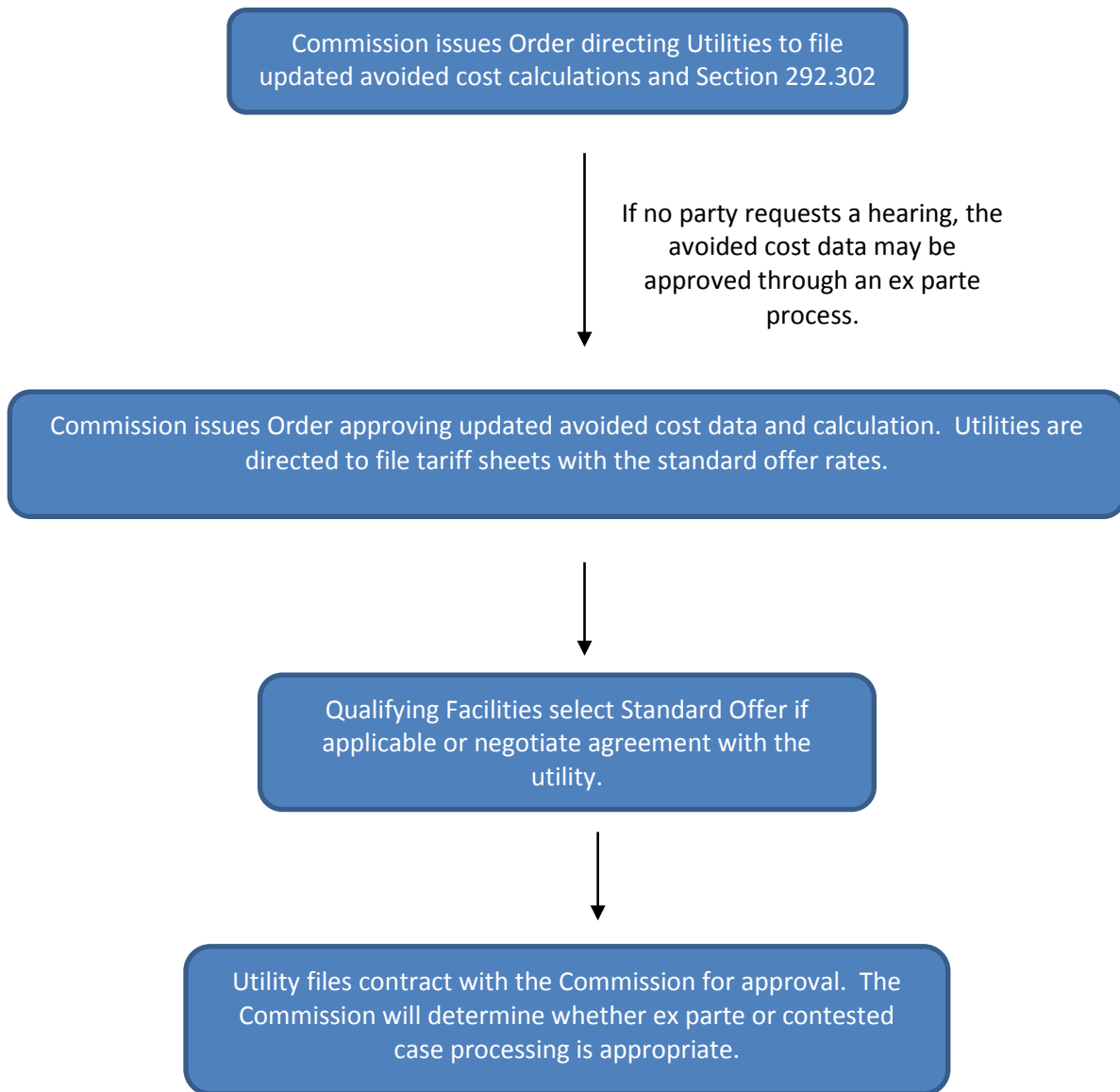
The scope and manner of the review of capacity charges for a qualifying facility shall be determined by the commission. Except as to approvals for qualifying facilities granted by the commission prior to June 1, 1987, proceedings before the commission seeking such approvals shall be conducted as a contested case pursuant to chapter 4 of the administrative procedures act of 1969, Act No. 306 of the Public Acts of 1969. [460.6j(13)(b).]

Another concern discussed during PURPA TAC meetings was the length of time needed to complete Staff's proposed administrative process; however, a shorter process was not identified.

Another goal of the PURPA TAC was to develop a routine administrative process to update avoided cost data on a regular basis. Staff proposes a biennial process in **Figure 4** below.

The purpose of the biennial process is to update the numbers (natural gas price forecast and market prices) used in the calculations. Once the utility files its updated avoided cost data in the docket, a party may request a contested case process. If no party requests a hearing, the updated avoided cost data can be approved through an ex parte process as quickly as two to three months.

Figure 4: Staff Recommendation –Administrative Process for Biennial Avoided Cost Calculation Updates



Avoided Cost

PURPA Regulations (18 CFR 292.101(b)(6)) define “avoided costs” as the following:

(6) *Avoided costs* means the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source.

Figures 5 and 6 describe the factors that may be considered in determining avoided cost and common avoided cost methodologies.

Figure 5: Factors that may be Considered in Determining Avoided Cost
FERC Rules: (18 CFR 292.304(e))

| |
|---|
| Availability of capacity or energy from a qualifying facility during the system daily and seasonal peak periods |
| Dispatchability and reliability |
| The relationship of the availability of energy or capacity from the qualifying facility to the ability of the electric utility to avoid costs, including the deferral of capacity additions and the reduction of fossil fuel use; and |
| The costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a qualifying facility, if the purchasing electric utility generated an equivalent amount of energy itself or purchased an equivalent amount of electric energy or capacity. |
| Source: Carolyn Elefant presentation to NARUC, March 2014 ⁷ |

⁷ See <http://www.narucmeetings.org/Presentations/25%20PURPA%20Avoided%20Cost%20Calculati on%20Differences%20Across%20States-Carolyn%20Elefant.pdf>

Figure 6: Common Avoided Cost Methodologies

| |
|---|
| Proxy Unit Methodology: Assumes that the utility is avoiding building a proxy generating unit itself by utilizing the QF's power. The fixed costs of this hypothetical proxy unit set the avoided capacity cost and the variable costs set the energy payment. |
| Peaker Unit Methodology which assumes that a QF allows the utility to avoid paying for a marginal generating unit on its system, usually a combustion turbine. The capacity payment is based on the fixed costs of the utility's least cost peaker unit and the energy payments are forecast payments for a peaker unit over the lifetime of the contract. |
| Differential Revenue Requirement Calculates the difference in cost for a utility with and without the QF contribution to generating capacity. |
| IRP Based Avoided Cost Methodology Relies on state integrated resource planning to predict future needs and costs that will be avoided by QF generation; based on IRP, may then apply proxy, DRR or other methodologies. |
| Market Based Pricing: QFs with access to competitive markets receive energy and capacity payments at market rates. |
| Competitive Bidding Allows states to utilize open, bidding processes. The winning bids are regarded as equivalent to the utility's avoided cost. |
| Source: Carolyn Elefant presentation to NARUC, March 2014 ⁸ |

The above FERC-accepted methods for determining avoided cost can result in a wide range of avoided costs. This report discusses several of the common avoided cost methodologies and describes Staff's recommended avoided cost methodology which utilizes a combination of the proxy unit and market based pricing methodologies.

Proxy Unit Methodology / Natural Gas Combined Cycle Plant (Staff Transfer Price)

One option for calculating avoided cost is the proxy plant method. Staff has performed a similar calculation for purposes of its Act 295 of 2008 (MCL 460.1001 et seq.) transfer price determination based on the levelized cost of a 400 MW proxy natural gas combined cycle (NGCC) plant.

This cost is projected in each year based on inflation rates, projections for materials and labor costs and natural gas price forecasts. An NGCC plant is assumed to be the most logical marginal plant. Since QFs would be offsetting the need for new capacity, some PURPA TAC participants argued that QFs should be compensated at this avoided cost rate.

Staff's transfer price schedule methodology is updated annually and covers the remaining time frame of the Act 295 renewable energy planning period (ending in 2029). Staff describes the transfer price schedules as representative of what a Michigan utility would pay had it obtained

⁸ See <http://www.narucmeetings.org/Presentations/25%20PURPA%20Avoided%20Cost%20Calculati on%20Differences%20Across%20States-Carolyn%20Elefant.pdf>.

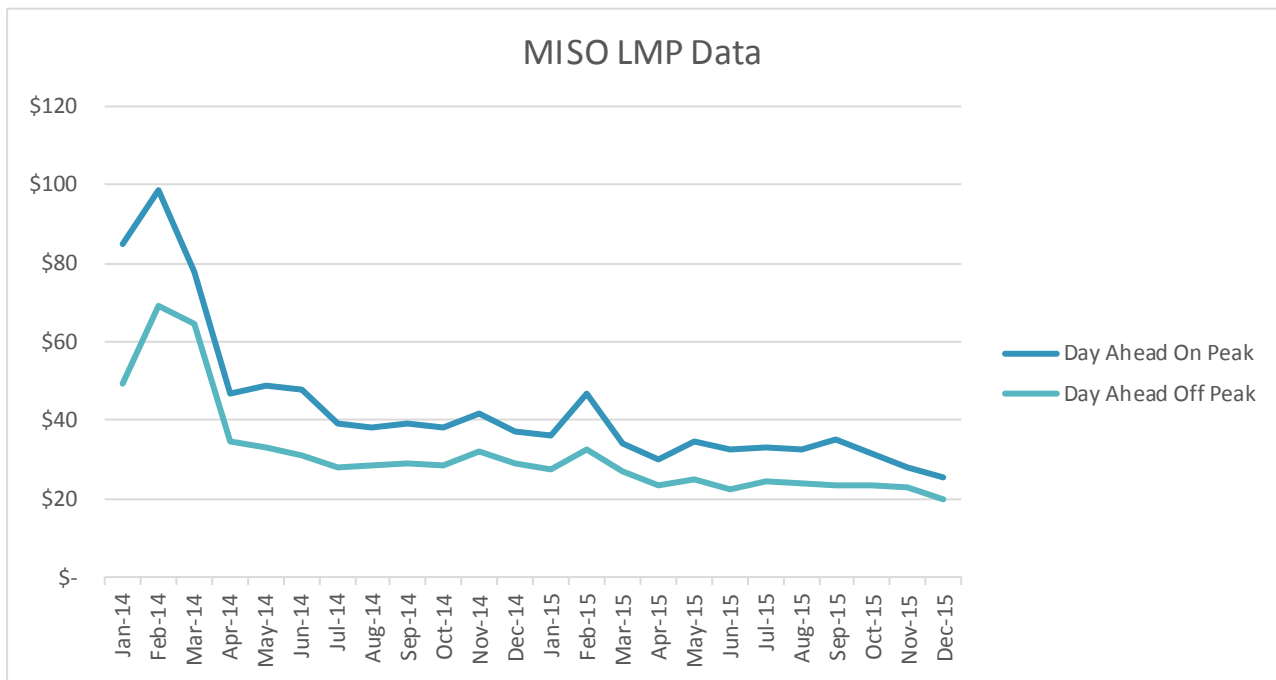
energy and capacity through a long term power purchase agreement for traditional fossil fuel electric generation.

The transfer price methodology is a function of Act 295. If the transfer price were to become the new avoided cost methodology, any modifications to the statute could also require modifications to the avoided cost methodology.

Market Based Pricing Methodology

This methodology values the QF’s energy at the Locational Marginal Price (LMP) calculated by the Midcontinent Independent System Operator (MISO) and capacity at the ISO capacity market price determined by the MISO Planning Reserve auction (PRA). For illustrative purposes, Staff included **Figure 7** below which shows average monthly LMPs from January 2014 through December 2015. **Figure 8** illustrates MISO’s PRA⁹ clearing price at the Michigan Hub in Zone 7 for 2015/2016 and Consumers Energy’s Zonal Resource Credit Reverse Auction results for zonal resource credits (ZRC)¹⁰ in years 2015/2016 through 2020/2021.

Figure 7: MISO Market Energy Pricing (Michigan Hub)¹¹



⁹ <https://www.misoenergy.org/Library/Repository/Report/Resource%20Adequacy/AuctionResults/2015-2016%20PRA%20Results.pdf>

¹⁰ <https://www.misoenergy.org/Planning/ResourceAdequacy/Pages/ResourceAdequacy.aspx> A zonal resource credit is equal to one megawatt discounted by the resources actual ability to deliver capacity when needed similar to the ELCC concept provided in Staff’s proposal.

¹¹ The Michigan Hub only includes prices from nodes in Michigan’s Lower Peninsula.

Figure 8: Market Capacity Pricing

| Market Capacity Value Description | Capacity Value \$ per MW-Year |
|--|-----------------------------------|
| MISO Zone 7 Planning Resource Auction | \$1,270 ¹² |
| Consumers Energy’s Zonal Resource Credit Reverse Auction Results | \$31,105 - \$59,900 ¹³ |

MISO holds a two-month one-year-out PRA. An overview of the capacity market is provided by a recent ICF white paper:

MISO’s resource adequacy construct provides compensation for resources not under a fixed resource adequacy plan (FRAP) for the value of having available energy in a particular geographic location. This construct aims to improve the reliability of the MISO electricity grid, especially during peak times when supply can be scarce. The capacity auction is prompt rather than forward looking like the ISO New England Inc. (ISO-NE) and PJM markets, meaning that capacity for the June–May annual planning period is procured in April of that same year. Participants bid into the auction for zonal resource credits (ZRCs) that are equivalent to one MW of capacity. ZRCs are for one-year obligations. The bids are cleared through a single, sealed-bid clearing price auction against a vertical demand curve, unlike PJM and ISO-NE where bids are cleared against sloping demand curves.¹⁴ The RA construct began with the 2013–2014 auction period. Previously, MISO conducted a voluntary capacity market with significantly low capacity prices and no incentives for localization.¹⁵

The MISO footprint has grown with the addition of Entergy. When Entergy is fully integrated into MISO, more access to capacity resources including the possibility to purchase capacity from the Southwest Power Pool will exist. The MISO auction covers one planning year; and the PJM base reliability auction covers three years. The capacity prices from these auctions represent the incremental cost of capacity, not the long-term cost that could be equivalent to the capacity added to a

¹² <https://www.misoenergy.org/Library/Repository/Report/Resource%20Adequacy/AuctionResults/2015-2016%20PRA%20Results.pdf>

¹³ <http://efile.mpsc.state.mi.us/efile/docs/17725/0001.pdf>

¹⁴ See discussion by MISO Independent Market Monitor <https://www.misoenergy.org/Library/Repository/Report/IMM/2014%20State%20of%20the%20Market%20Analytical%20Appendix.pdf>, page 22 & 23.

¹⁵ See icfi.com, MISO’s Capacity Auction: Uncertainty Going Forward, By Himanshu Pande and Rachel Green, 2015

utility's system by a QF. The MISO PRA provides a balancing function and according to a MISO Staff Draft Proposal dated March 18, 2016 titled *Competitive Retail Solution*,¹⁶ the existing PRA was not designed to meet "...the need to maintain existing and/or invest in new resources necessary to assure resource adequacy in competitive retail areas that rely exclusively on markets."

Staff's Modified Proxy Plant Methodology – Staff's Strawman

Staff's recommended avoided cost methodology utilizes a combination of the proxy unit and market based pricing methodologies. As presented in this report, Staff proposes a Modified Proxy Plant Methodology to mitigate the risk of re-evaluation of PURPA avoided cost rates. Utilizing components from both the proxy plant methodology and the market based methodology; Staff developed a "modified proxy plant methodology."

Capacity Component

For capacity, Staff utilizes a natural gas combustion turbine (CT) value, similar to MISO's calculation of the Cost of New Entry (CONE).¹⁷ Staff recommends that capacity payments be paid to the QF on a monthly basis rather than spread over the MWh of generation during the month. Below is an example of the Staff-proposed calculation methodology. Each utility would provide inputs to the methodology that would reflect its actual economic outlook and experience with the operating characteristics of the specific generation type or conversely, the ISO average.

¹⁶

<https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/CRSTT/Draft%20CR%20FCA%20Proposal%20CoreDesign.pdf>

¹⁷

<https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/SAWG/2015/20151029/20151029%20SAWG%20Item%2004%20CONE%20PY%202016-2017.pdf>

Figure 9: Levelized Cost Calculation Simple Cycle Gas Turbine

| | CT No Variable | notes |
|---------------------------------|-----------------------------|---|
| Capacity MW | 210 | MW |
| Loading Factor | 13.00% | The % of time the unit would be dispatched if available |
| Equivalent Avail. | 90.00% | The % of time the unit would be available for dispatch. |
| Capacity Factor | 11.70% | (Loading Factor)*(Equivalent Availability) |
| Heat Rate Btu/kWh | 9750 | BTU/kWh |
| Fuel Cost \$/MMBtu | \$0.00 | \$ per Million BTU |
| Total Cost MM no AFUDC | \$160.049 | MM |
| AFUDC | \$20.34 | MM |
| Total Cost MM | \$180.388 | MM |
| Fixed Charge Rate | 9.3% - 12.38% | % used to calculate fixed cost recovery component |
| Fixed O&M \$/kW | \$14.62 | \$/kW |
| Annual Lev. Fixed Cost MM | \$16.78 - \$22.33 | MM |
| Total Annual Lev. Fixed Cost MM | \$19.85 - \$25.40 | MM |
| Fixed Cost \$/kWh | 0.0922 – 0.1180 | \$/kWh |
| Fuel Cost \$/kWh | 0.0000 | \$/kWh |
| Var. O&M \$/kWh | 0.0000 | \$/kWh |
| Total Var. Cost | 0.0000 | \$/kWh |
| Total Cost \$/kWh | 0.09221 – 0.11802 | \$/kWh |
| Total Cost (MM) | | |
| Overnight Cost (MM) Inflated | | |
| Total Cost (\$/kW) | | |
| \$/MW-year | \$94,506 - \$120,963 | This price represents the cost of capacity |

To accurately value the capacity of a variety of differing generation types, such as intermittent generators, a ratio is applied based on the Effective Load Carrying Capability (ELCC) of the QF. The ELCC recognizes the historical availability of the generation type during on-peak periods. MISO provides ELCC estimates for most new generation types based on system averages. After a period of actual generation characteristics have been analyzed, individual units are assigned an ELCC. The ELCC is multiplied by the yearly capacity value to accurately account for actual availability and is especially critical for intermittent resources such as solar and wind QFs. Staff recommends that MISO’s ELCC ratios be applied to intermittent generator resources.

Staff utilized a fixed charge rate (FCR) of 9.3 percent in its calculation presented at the February 10, 2016, PURPA TAC meeting based on the formula $FCR = \frac{r}{(r+1)^t - 1} + r$, where r = pre-tax cost of capital and t = asset life (for our purposes, Staff utilized Consumers Energy’s

weighted average cost of capital (WACC) of 8.92 percent and a 38 year asset life.)¹⁸ This FCR was presented for illustrative purposes and resulted in a capacity component of \$94,505.94, which is comparable to MISO’s CONE. An alternative method for calculating an average FCR specific to Consumers Energy is shown below¹⁹:

| | |
|--------------------------|---------------|
| WACC | 8.92% |
| Accumulated Depreciation | -3.07% |
| Depreciation Expense | 5.01% |
| Property Taxes | 0.97% |
| Fixed Charge Rate | 11.83% |

Staff finds merit in including a range of FCRs based on the 12.38 percent FCR vetted during the transfer price process²⁰ and the 9.3 percent FCR initially presented in its strawman. This FCR range and the effects on each component have been included in **Figures 9, 11, and 12.**

The expert from the *Handbook of Electric Power Calculations*; contributor Hesham E. Shaalan; Section 8, titled; *Generation of Electric Power*, as provided in the comments below, states that FCRs for investor-owned utilities typically range from 15 to 20 percent.²¹ It is important to note that the utility economic climate has varied since the 2001 copyright date of this publication and the effects of variables such as accelerated depreciation, tax credits, and debt rates may impact the FCR. The FCR will need to reflect any variability in these components.

Capacity Payments and Planning Horizon

Under PURPA, utilities have a must-purchase obligation for QFs 20 MW and smaller. One of the complexities of PURPA is determining the value of capacity under different capacity need circumstances. The capacity landscape in Michigan and across MISO and neighboring PJM is changing dramatically due to the planned retirement of coal plants and the expected increased utilization of natural gas plants. Also, pending legislation in the Michigan legislature includes an integrated resource planning process that could significantly influence how capacity is added in the future.

Capacity markets in MISO and PJM are based on one year or three year forward auctions. To the extent capacity prices spike, due to large retirements of coal units, the reflective cost of capacity would be an undue risk to utilities. Due to the 10 year data requirements for capacity plans outlined in PURPA, Staff recommends the utilities utilize a ten year capacity planning horizon.

While Michigan has not seen growth in the amount of QF capacity, other states are experiencing tremendous amounts of new PURPA contract capacity – especially solar QFs. The

¹⁸ <https://www.e-education.psu.edu/eme801/node/560> The fixed charge rate or capital charge factor is a formula used to determine the yearly dollar amount necessary to recover costs associated with an investment. This factor is multiplied by the total capital costs to determine yearly cost recovery.

¹⁹ Inputs from Case No. U-17735 work-papers. <http://efile.mpsc.state.mi.us/efile/viewcase.php?casenum=17735>

²⁰ While Staff’s Transfer Price Schedule has been an issue of debate in proceedings, the FCR has never been specifically contested by intervening parties.

²¹ [http://www.mz3r.com/fa/wp-content/uploads/2012/02/books/ebooks/\[McGraw%20Hill\]%20-%20Handbook%20of%20Electric%20Power%20Calculations.pdf](http://www.mz3r.com/fa/wp-content/uploads/2012/02/books/ebooks/[McGraw%20Hill]%20-%20Handbook%20of%20Electric%20Power%20Calculations.pdf)

situation in the State of Idaho in which the total capacity of QFs seeking contracts under PURPA was approaching the utility's full load poses significant concern.²² The Idaho PUC reduced PURPA contract lengths to two years in response.

No consensus was reached during the PURPA TAC meetings with respect to how capacity payments would be determined. As a result of existing PURPA contracts already being part of a utility's portfolio, Staff recommends that QFs should be offered the full avoided cost capacity rate when their contracts are considered for renewal. Staff supports a standard rate for exiting QFs at the time of contract renewal and QFs that are 5 MW and smaller which includes the full avoided cost capacity rate. Out of the 37 PURPA contracts with QFs 20 MW or smaller in Consumers Energy's and DTE's portfolios, 26 are 5 MW and smaller. The 5 MW and smaller standard offer would be available to 70% of Consumers Energy's and DTE's 20 MW and smaller existing PURPA contracts.

The Staff proposes three capacity payment options for the Commission to consider for new QFs larger than 5 MW and no larger than 20 MW:²³

Option 1 – Capacity payments to the QF at the full avoided cost capacity rate shown in Figure 9 discounted for the ELCC for intermittent resources regardless of the utility capacity needs.

Option 2 – Capacity payments to the QF at the full avoided cost capacity rate discounted for the ELCC for intermittent resources until the utility demonstrates to the Commission that capacity additions are not necessary. The capacity needs of the utility would be examined by the Commission. If capacity is not required in the PURPA 10 year planning horizon, the capacity payment would be zero. If capacity is needed, then the full avoided capacity cost would be paid for the term of the contract.

Option 3 - During the PURPA TAC meetings, Staff presented the concept of establishing a fixed capacity payment based on a fraction of a full capacity payment. This concept accounts for lumpy investments in capacity that cause the capacity auction market to have "boom and bust" capacity cycles. In its Solar Gardens filing in MPSC Case No. U-17752, Consumers Energy requested and received Commission approval to use 75% of MISO's CONE for the capacity payment component of the Solar Gardens solar energy credit.²⁴ This calculation is based on Consumers Energy's capacity forecast and accounts for the long term value of capacity in MISO's planning reserve auction. Under this option, the QF would receive capacity payments, regardless of utility capacity needs, at 75% of the avoided capacity rate determined through Staff's strawman and discounted for the appropriate ELCC for intermittent resources. Note, existing QFs and QFs that are 5 MW or smaller would receive the full capacity rate with the ELCC applied for intermittent technology types.

²² http://www.puc.idaho.gov/press/150820_PURPAfinal_files.pdf

²³ See **Appendix C** for Consumers Energy's proposal which includes criteria for determining capacity payments under four different ZRC need scenarios. A brief description of the proposal is also included in the Alternative Avoided Cost Proposals and Comments section of this report.

²⁴ <http://efile.mpsc.state.mi.us/efile/docs/17752/0043.pdf>

Energy Component

Staff's strawman also offers three options for determining the energy component payment. Staff proposes that the QF have the opportunity to select the option that most effectively suits their needs:

Option 1 - Utilize LMP market based rates. This rate would be the actual LMP on an hourly or monthly average basis and is considered the "...avoided cost at the time of delivery." 18 CFR 292.304(b)(5)

Option 2 - The utility forecasts LMPs over the contract period and pays for energy on an hourly or monthly average basis according to the forecast. 292.304(b)(5) provides that "...rates for purchases are based upon estimates of avoided costs over the specific term of the contract or other legally enforceable obligation, the rates for such purchases do not violate this subpart if the rates for such purchases differ from avoided costs at the time of delivery."

Option 3 - The utility pays for energy based on the forecasted variable costs of an NGCC as calculated in the Staff Transfer Price. **Figure 10** shows Staff's estimate of NGCC variable costs through 2045.

Figure 10: Natural Gas Combined Cycle Variable Costs²⁵

| Year | Staff Projection NGCC Variable Cost |
|-------------|--|
| 2016 | \$36.79 |
| 2017 | \$38.22 |
| 2018 | \$38.88 |
| 2019 | \$40.16 |
| 2020 | \$41.47 |
| 2021 | \$43.30 |
| 2022 | \$45.35 |
| 2023 | \$45.94 |
| 2024 | \$47.01 |
| 2025 | \$48.26 |
| 2026 | \$48.74 |
| 2027 | \$49.78 |
| 2028 | \$52.17 |
| 2029 | \$54.00 |
| 2030 | \$55.34 |
| 2031 | \$57.61 |
| 2032 | \$58.70 |
| 2033 | \$59.53 |
| 2034 | \$61.13 |
| 2035 | \$62.14 |
| 2036 | \$63.72 |
| 2037 | \$65.44 |
| 2038 | \$67.05 |
| 2039 | \$68.46 |
| 2040 | \$70.23 |
| 2041 | \$72.25 |
| 2042 | \$74.36 |
| 2043 | \$76.54 |
| 2044 | \$78.80 |
| 2045 | \$81.12 |

²⁵ Staff's projection is based on the natural gas forecast in the EIA 2015 Annual Energy Outlook and indices from Global Insight.

Fixed Investment Cost Attributable to Energy

Staff's strawman energy payment to the QF includes a fixed investment cost attributable to energy (ICE) in addition to the LMP. The rationale is that to obtain cheaper energy from an NGCC (as opposed to a CT), the additional capacity costs to build an NGCC are incurred over and above the cost to build a CT. This shifted "capacity" cost should be added to the energy payment.

An NGCC has lower energy cost, but higher capacity cost. The NGCC fixed ICE is calculated using the fixed capacity cost difference between an NGCC and a CT. Staff calculates this value by subtracting the fixed costs to construct a CT from the fixed costs to construct an NGCC. This difference in cost is paid on a volumetric basis and is added to the energy payment to accurately represent a true energy value.

Some commenters said that using a CT for capacity payments, NGCC variable costs or LMP for the energy payment and adding a fixed ICE creates complexity. There is strong justification for valuing capacity at a CT because it is the unit that would be built if pure capacity were needed. Where energy is needed, an NGCC would be selected. The fixed ICE is needed to achieve the full value of a new plant.

Figure 11: Fixed Investment Cost Attributable to Energy

| | NGCC | notes |
|--|----------------------------|---|
| Capacity MW | 400 | MW |
| Loading Factor | 71.00% | The % of time the unit would be dispatched if available |
| Equivalent Avail. | 87.00% | The % of time the unit would be available for dispatch. |
| Capacity Factor | 61.77% | (Loading Factor)(Equivalent Availability) |
| Heat Rate Btu/kWh | 6719 | BTU/kWh |
| Fuel Cost \$/MMBtu | \$5.01 | \$ per Million BTU |
| Total Cost MM no AFUDC | \$460.065 | MM |
| AFUDC | \$62.91 | MM |
| Total Cost MM | \$522.972 | MM |
| Fixed Charge Rate | 9.3% - 12.38% | % used to calculate fixed cost recovery component |
| Fixed O&M \$/kW | \$14.62 | \$/kW |
| Annual Lev. Fixed Cost MM | \$48.64 - \$64.74 | MM |
| Total Annual Lev. Fixed Cost MM | \$54.48 - \$70.59 | MM |
| Fixed Cost \$/kWh | 0.0252 – 0.0326 | \$/kWh |
| Fuel Cost \$/kWh | 0.0337 | \$/kWh |
| Var. O&M \$/kWh | 0.0031 | \$/kWh |
| Total Var. Cost | 0.0368 | \$/kWh |
| Total Cost \$/kWh | 0.06196 – 0.06940 | \$/kWh |
| Overnight Cost (MM) Inflated | 434.32 | |
| Total Cost (\$/kW) | \$1,085.80 | |
| \$/MW-year | \$335,259 - \$375,528 | |
| \$/MW-year no variable | \$136,211 - \$176,480 | |
| CC-CT \$/MW-year | \$41,705 - \$55,517 | |
| Total Annual Lev. Fixed Cost MM Difference | \$16.68 - \$22.21 | |
| Fixed Cost \$/kWh | \$0.0077 - \$0.0103 | \$/kWh represents the fixed ICE |

Examples of how the avoided cost elements discussed above are applied to specific types of QFs are presented in **Figure 12**.

Figure 12: Staff Strawman – 20 MW Qualifying Facility Example

| <h2 style="text-align: center; margin: 0;">Staff Strawman Example - 20 MW Qualifying Facility</h2> | | | | | | |
|--|------------------------------|-------------------|-------------------------|---|-----------------------|--------------------------|
| | Capacity Factor % (Estimate) | ELCC % (Estimate) | Capacity Annual \$1000s | Energy (Option 1 – LMP at time of delivery) \$/MWh (MISO LMP December 2015 Average) | NGCC fixed ICE \$/MWh | Total Energy \$/MWh |
| Hydro | 60% | N/A | \$1,890 - \$2,419 | \$22.63 | \$7.71 - \$10.26 | \$30.34 - \$32.89 |
| Biomass | 80% | N/A | \$1,890 - \$2,419 | \$22.63 | \$7.71 - \$10.26 | \$30.34 - \$32.89 |
| Landfill Gas | 85% | N/A | \$1,890 - \$2,419 | \$22.63 | \$7.71 - \$10.26 | \$30.34 - \$32.89 |
| Solar | 20% | 43% | \$813 - \$1,040 | \$22.63 | \$7.71 - \$10.26 | \$30.34 - \$32.89 |
| Wind | 35% | 15% | \$284 - \$363 | \$22.63 | \$7.71 - \$10.26 | \$30.34 - \$32.89 |

Alternative Avoided Cost Proposals and Comments

Staff asked for comments to its strawman by Wednesday, February 24, 2016. Staff received Comments from Consumers Energy, Varnum Law Firm, on behalf of the Independent Power Producer Coalition (IPPC), and jointly filed comments from the Environmental Law and Policy Center (ELPC) and 5 Lakes Energy. This section will summarize those comments. Copies of the written comments received are provided in *Appendix C*.

Consumers Energy

Consumers Energy provided a proposal that utilized four QF capacity payments based on the utility's capacity need (resource adequacy) in the form of MISO ZRCs.

1. For zero capacity need, the utility would pay no capacity component and the energy payment should equal LMP.
2. For less than 200 ZRCs, the avoided capacity should be based on MISO's PRA, and the energy payment should equal LMP.
3. For 200 ZRCs but less than 1000 ZRCs, the capacity payment should be the combustion turbine fixed costs and the energy payment should equal LMP.
4. For a capacity need over 1000 ZRCs, the capacity payment should be based on a natural gas combined cycle plant and the energy payment should equal LMP.

Consumers Energy was concerned with the use of a levelized cost for determining Staff's avoided cost methodology. The company stated that levelizing the plant costs front-loads a disproportionate amount of plant costs over the term of the contract since the contract term would be a much shorter duration than the term used in the levelization calculation (typically 20 to 40 years). Instead, Consumers Energy proposed using an economic carrying charge, which would account for this and provide a capacity calculation that would escalate at a rate equal to inflation or similar index.

Consumers Energy supported paying for energy based on the actual LMP (price at delivery). However, if there is a legally enforceable obligation, PURPA may give the QF an option to be paid according to a forecast. Consumers Energy also explained that the energy payment should be the lesser of the LMP or the avoided plant variable costs. This, Consumers Energy stated, assures that the QF would receive the correct economic signals similar to the way Consumers Energy's plants are dispatched by MISO. If cheaper forms of energy are available, the less expensive energy plant is dispatched first. Consumers Energy did not support Staff's proposal to include a fixed ICE in the energy payment.

Independent Power Producers Coalition

The IPPC comments primarily supported Staff's transfer price methodology. The IPPC stated that the transfer price is the best representation of what a true avoided cost template is: "(t)ransfer price schedules are representative of what a Michigan electric provider would pay had it obtained the energy and capacity (the non-renewable market price component) through a new long term power purchase agreement for traditional fossil fuel generation. To best determine the value of the non-renewable component of Act 295 compliant generation, Commission Staff determined for purposes

of developing a uniform Transfer Price Schedule that the levelized cost of a new natural gas combined cycle (NGCC) would likely be analogous to the market price mentioned above.”

The IPPC stated that the actual LMP, even a levelized forecast, does not accurately account for the long term contract value of the energy and favors the levelized variable costs of a NGCC for the energy component. It states that utilities look at long-term trends related to fuel cost, load growth and other factors in its planning horizon and spot markets prices do not reflect these values.

Environmental Law and Policy Center / 5 Lakes Energy

ELPC and 5 Lakes Energy support Staff’s strawman. Additionally, ELPC and 5 Lakes Energy are supportive of a technology specific capacity credit that is more detailed than simply average ELCC. They support a generator specific ELCC to account for technological and location specific benefits such as solar tracking and higher wind speed areas. ELCP and 5 Lakes also support the addition of certain cost adders to the avoided cost that account for the nature of QF generation. These adders are:

1. Avoided Transmission Costs – the distributed nature of the sub-transmission voltage interconnected generation, at least, partially reduces the need for transmission costs to the utility.
2. Avoided Line Losses – again, distributed generation that serves load in the local area avoid line and transformer losses.
3. Hedge Value – long term contracts reduce the Company’s fuel price uncertainty.
4. Avoided Emissions and Environmental Compliance Costs – While renewable energy credits can accrue to the QF, carbon credits or allowances may be allocated elsewhere.

PURPA Regulations, Section 292.302, Filing Requirements

To develop an on-going, routine Commission administrative process for determining avoided cost for 20 MW and smaller PURPA projects, Staff recommends the Commission order the following minimum biennial data collection and reporting requirements for each electric utility regulated by the Commission.

1. The requirements listed in 292.302 of Title 18 of the Code of Federal Regulations:
 - a. To provide to the State regulatory authority and maintain for public inspection the following:
 - i. The estimated avoided cost on the electric utility’s system, solely with respect to the energy component, for various levels of purchases from qualifying facilities. Such levels of purchases shall be stated in blocks of not more than 100 megawatts for systems with peak demand of 1000 megawatts or more, and in blocks equivalent to not more than 10 percent of the system peak demand for systems of less than 1000 megawatts. The avoided costs shall be stated on a cents per kilowatt-hour basis, during daily and seasonal peak and off-peak periods, by year, for the current calendar year and each of the following five years.

- ii. The electric utility's plan for the addition of capacity by amount and type, for purchases of firm energy and capacity, and for capacity retirements for each year during the succeeding 10 years.
 - iii. The estimated capacity costs at completion of the planned capacity additions and planned capacity firm purchases, on the basis of dollars per kilowatt, and the associated energy costs of each unit, expressed in cents per kilowatt hour. These costs shall be expressed in terms of individual generating units and of individual planned firm purchases. [18 CFR 292.302(b)(1)–(3).]
 - iv. With regard to an electric utility which is legally obligated to obtain all its requirements for electric energy and capacity from another electric utility, provide the data of its supplying utility and the rates at which it currently purchases such energy and capacity. [18 CFR 292.302(c)(1)(ii).]
2. Additional biennial filing requirements as recommended by Staff:
- a. The complete and detailed calculation of the avoided costs to be paid to a qualifying facility based on energy and capacity forecasts.
 - i. The capacity cost portion of the avoided cost is to be based on the fixed cost component capacity cost associated with CT.
 - ii. The energy cost portion of the avoided cost is to be a result of an energy fixed ICE in addition to either LMP, as determined by MISO or PJM, at the electric utilities' node, forecasted LMP or levelized NGCC plant variable costs. The electric utility shall provide the above data to calculate all three options within its biennial filing to the Commission. Such data will include a 17.5 year forecast of LMP.
 - iii. The utility will file its standard offer for QFs with nameplate capacity equal to or less than 5 MW.
 - iv. The effective load carrying capability for intermittent renewable generation such as solar and wind energy.

Additional Considerations

Market Changes since the Passage of PURPA

Since the passage of PURPA, RTOs and ISOs have come into existence. The open access provided by these organizations spawned the creation of markets for electricity, including capacity and other energy products. Michigan electric providers can participate in either or both RTOs. While the calculation and formulation of an energy price is similar in the two organizations, the constructs to determine capacity prices are quite different. If the Commission decides to use wholesale markets for guidance, it will need to decide the best of PJM and MISO processes when considering and devising alternatives for determining the capacity component of a new avoided cost methodology.

There are barriers to QF participation in the RTO/ISO markets. In addition to administrative costs and technical requirements to become a market participant, for QFs connected to the utility's distribution system, it would be necessary to use the utility's distribution system to reach wholesale

markets. This activity would almost certainly be cost prohibitive and would represent a barrier to the QF's ability to participate in the markets. Consumers Energy stated that for QFs 20 MW and smaller and interconnected to its distribution system, it would provide free access to the MISO market (register the QF in the market and transfer market payments to the QF). This may be an attractive option to QFs under certain circumstances.

Presence of Alternate Electric Suppliers (AES)

The presence of AESs presents complications when discussing PURPA, as they are not subject to mandatory purchase obligations. One utility mentioned that the introduction of AESs and the hybrid choice market in Michigan is the single largest change that has occurred in Michigan since PURPA was introduced in 1978. In Michigan's customer choice program, AESs are limited to supplying up to 10% of a utility's load. If PURPA were to cause the cost of a utility's electricity to increase, then it is possible that the utility could be susceptible to losing additional load to an AES.

If the avoided cost methodology is done correctly, and other variables are equal, the electricity supply market should have no preference between AES, utility owned supply or utility contracted PURPA generation. This is just another reason why setting the avoided cost, and the terms associated with it, is so important.

The two major Michigan utilities are already at the statutory cap for customer choice so the utilities could be at-risk for losing additional load if legislative changes were to adjust the customer choice cap upward without requiring AESs, and others who wish to serve Michigan retail customers, to have the same obligation to show that they hold and can provide capacity similar to utilities. Without an appropriately set avoided cost methodology, AESs could attract more of the utility's load while only the utility retains a mandatory purchase obligation for PURPA. This situation could result in premature retirement of generation assets and potentially stranded cost. The Commission may want to consider passing some costs paid by utilities under PURPA's mandatory purchase obligation onto AESs. AESs have expressed resistance to any PURPA related costs being passed on to them.

Ancillary Services

PJM has additional generator payments that do not exist in MISO. Some of these are for performance criteria, black start capability and the ability to ramp generation down to supply only station power to stay operational during a utility system outage. Staff believes that the capabilities of QFs could be compensated if the services they provide are not already included in the cost of the selected proxy plant. In the case of Staff's proposed modified proxy plant methodology, it can be assumed that the proxy provides some items such as voltage support and quick ramping capability. It cannot be assumed that the proxy plant has black start capability unless the costs of the proxy plant include a battery bank or diesel generator to black start the combustion turbine. The Commission has the latitude to consider compensating QFs for these generation services even if the utility and QF are located in MISO and there is no market in MISO for these services.

Renewable Energy Credits and Environmental Attributes

Renewable Energy Credits (RECs) and the related market were created in Michigan as part of Act 295. Since the original PURPA contracts did not foresee the creation of a REC value, it was determined through the legislative process that 80% of the RECs would belong to the utility and 20% would belong to the QF. At least one utility has recommended that all RECs should be provided to the utility at no cost as compensation for the utility must purchase obligation.

On the other hand, the choice of a natural gas proxy plant results in a proxy that generates no RECs. Therefore the benefits of renewable energy are not included in the avoided cost calculated by the natural gas proxy plant. Staff recommends that all RECs belong to the QF when the choice of proxy plant does not generate RECs and that the sale of RECs to the utility can be negotiated and included in the price of the contract if both the QF and the utility mutually decide to do so.

Carbon benefits are difficult to quantify using information that is currently known. It is possible in the future that such information will become more developed and will influence the calculation of PURPA avoided cost. Staff recommends that carbon benefit compensation be considered at a later time, possibly when Michigan finalizes its State Implementation Plan under the Clean Power Plan or at a time when carbon benefits are more clearly understood and dependably quantifiable.

Avoided Transmission Costs and Avoided Line Loss

Distributed generation has the potential to reduce transmission costs, and can help to mitigate line losses. This benefit is location specific because it depends on the unique supply and load characteristics of the local area. Staff recommends that transmission costs and line loss mitigation with respect to the avoided cost calculation be evaluated on a case by case basis for inclusion in the avoided cost rate, at the request of the QF.

Standard Rate Offer

PURPA Regulations, Section 292.304, require utilities to offer a standard rate for purchases:

(c) *Standard rates for purchases.*

(1) There shall be put into effect (with respect to each electric utility) standard rates for purchases from qualifying facilities with a design capacity of 100 kilowatts or less.

(2) There may be put into effect standard rates for purchases from qualifying facilities with a design capacity of more than 100 kilowatts.

(3) The standard rates for purchases under this paragraph:

(i) Shall be consistent with paragraphs (a) and (e) of this section; and

(ii) May differentiate among qualifying facilities using various technologies on the basis of the supply characteristics of the different technologies.

Staff supports a standard rate for existing QFs (at the time of contract renewal) and QFs that are 5 MW and smaller which includes the full avoided cost capacity rate, one of Staff's proposed energy options and the fixed ICE. Making the standard offer rate available to existing QFs and QFs that are 5 MW and smaller aligns with Staff's Option 1 for capacity purchases.

A review of the 37 existing PURPA contracts with QFs 20 MW or smaller in Consumers Energy's and DTE's portfolios shows that 26 are 5 MW and smaller. Based on this historical information, a majority of QFs would fall under the standard rate offer. A standard rate offer for new QFs that are 5 MW and smaller may reduce transaction costs by reducing the time necessary for the QF to negotiate with the utility and provides certainty for obtaining QF financing. The length of the standard rate offer is discussed in the Contract Length section of this report.

Contract Length

Historically, PURPA contracts in Michigan have been long term, with some more than 30 years. Staff recommends a contract term that spans the shorter of either the QF financing period or 17.5 years for new QFs as provided in Act 81 for both standard rate offer contracts and those above 5 MW. Determining the appropriate contract length for existing QF contract renewals is more complex. For these QFs, Staff recommends a case by case determination which includes consideration of the QF's financing needs and potentially other factors.

Act 81 says in part:

The financing period for a qualifying facility during which previously approved capacity charges shall not be subject to commission reconsideration shall be 17.5 years, beginning with the date of commercial operation, for all qualifying facilities, except that the minimum financing period before reconsideration of the previously approved capacity charges shall be for the duration of the financing for a qualifying facility which produces electric energy by the use of biomass, waste, wood, hydroelectric, wind, and other renewable resources, or any combination of renewable resources, as the primary energy source. [MCL 460.6j(13)(b)(ii).]

Standby Service and Interconnection

The PURPA law includes two additional major areas of regulation: standby service and interconnection. While establishing the goals of PURPA TAC, Staff asked the group to forgo both topics to keep the focus on developing a workable administrative process and investigate avoided cost methodologies.

In the case of standby service, there is currently a separate Staff working group addressing that issue with a report due in August 2016. Regarding interconnection, the Commission has established Electric Utility Interconnection & Net Metering Standards.²⁶

²⁶ See http://w3.lara.state.mi.us/orrsearch/107_97_AdminCode.pdf

Interconnection Procedures for smaller projects that are 150 kW and less are in place and working well.²⁷ Staff recommends that a workgroup be started where the goal would be to develop Interconnection Procedures for larger projects.

FERC PURPA Technical Conference

Several members of the Senate and House of Representatives in Washington, DC have called for FERC to re-examine the current need for PURPA. FERC has announced that it will hold a technical conference on June 29, 2016. The focus of the conference will be on two items: the mandatory purchase obligation and the determination of avoided costs. On March 4, 2016 FERC put out a “call for speakers” for the technical conference.

It is likely that the speakers who are selected will have a variety of opinions. A consensus understanding of the two issues being discussed seems unlikely. What seems more likely is that this FERC conference will be a catalyst for more conferences, or a FERC response, which in turn, could lead to more discussion and possibly shaping of a FERC rulemaking or draft legislation in Congress.

While the discussion of PURPA at FERC and the federal level is helpful and should be monitored, it is unlikely to be timely enough for Michigan to wait for the federal government to act. Once Michigan puts in place a routine for examining PURPA, it is likely that any changes made to PURPA can be incorporated into future contested cases in Michigan.

Conclusion

Staff would like to thank all PURPA TAC participants for their contributions to the group’s efforts. The input helped shape Staff’s recommendations in this report.

Staff recommends the use of its modified proxy plant methodology and supports a standard rate which includes the full avoided cost capacity rate, one of Staff’s proposed energy options and the fixed ICE for existing QFs at the time of contract renewal and new QFs that are 5 MW and smaller.

Summary of Substantive Revisions to the Draft Report

On March 15, 2016 Staff released a draft version of this report the PURPA TAC requesting comments by April 1, 2016 (April 1 comments). Consumers Energy Company, DTE Electric Company, EnStar Energy, LLC., Energy MI, Varnum Law on behalf of the Independent Power Producers Coalition and Environmental Law and Policy Center filed jointly with 5 Lakes Energy filed written comments. The April 1 comments are included in *Appendix D*. Substantive changes made to the report based on comments provided are listed below:

²⁷ See http://www.michigan.gov/mpsc/0,4639,7-159-16393_48212---,00.html

- The report was clarified to show that the Staff proposed recommendation includes existing QFs being offered the full avoided cost capacity rate adjusted for ELCC at the time their contracts are renewed.
- The Fixed Charge Rate used for determining the NGCC plant levelized costs is now presented as a range of values.
- References to using the capacity needs of an LRZ to determine whether a utility needs capacity were removed.
- Staff's proposal is revised to reflect that a QF may request a determination of avoided transmission costs and line loss benefits be included in its avoided cost rate.

Appendix A- PURPA TAC Meeting Summaries

A series of five in-person PURPA TAC meetings were held from December 2015 through March 2016. All meetings were available in-person or via webinar. Meeting attendance was between 30 and 40 in-person attendees and approximately 20 webinar participants. Presentations from each meeting are available at the Staff's [PURPA website](#). A brief summary of each meeting is included below.

December 8, 2015

The initial PURPA TAC meeting was held on December 8, 2015. Carolyn Elefant, J.D., a noted PURPA expert, provided an overview of PURPA. She outlined the goals, requirements and state and federal responsibilities. She explained six common avoided cost methodologies; Proxy Unit Methodology, Peaker Unit, Differential Revenue Requirement, IRP based avoided cost methodology, market based pricing and competitive bidding. She also described PURPA implementation examples from select states: North Carolina, Montana, Utah, Idaho, Oregon and Vermont. Staff presented the timing for future meetings and proposed PURPA TAC goals.

January 13, 2016

Staff gave an overview of the original U-6798 implementation process and discussed U-8871. Staff presented its administrative process strawman.

February 3, 2016

The February 3 meeting was added at the request of the Independent Power Producers Coalition (IPPC) of Michigan to present their thoughts on PURPA and describe the varying characteristics of each type of QF. Ken Rose, Independent Consultant, presented an overview of PURPA. Tim Lundgren from Varnum Law described the overall benefit of having small QF's on the power grid. Bill Stockhausen of Elk Rapids Hydro explained the benefits of hydroelectric facilities. Darwin Baas of Kent County presented the benefits of having an integrated solid waste management system. Marc Pauley of Granger presented the benefits of utilizing landfill gas. Thomas Vine of Viking Energy presented the benefits of biomass. Douglas Jester of 5 Lakes Energy discussed combined heat and power and solar.

February 10, 2016

Jesse Harlow, Staff Engineer, presented the Staff's avoided cost methodology strawman. Julie Baldwin, Staff Manager of the Renewable Energy Section, outlined a revised and updated PURPA administrative process. Written comments on both proposals were requested by Staff.

March 3, 2016

The final meeting provided an opportunity to discuss the written comments that were provided by Consumers Energy, IPPC and the Environmental Law and Policy Center/5 Lakes Energy.

Appendix B

| Consumers Energy PURPA Contracts | | | | | | | | | | | |
|----------------------------------|--|-----------------|-------------|----------|---|---|---|-----------------------|------------------------|---------------|---------------------------|
| Line No. | Generator | Technology Type | Capacity MW | 2014 MWh | Energy | 2014 Actual Variable Energy Cost \$/MWh | Capacity | Administrative Charge | 2014 Total Cost \$/MWh | 2014 Total \$ | Contract Termination Date |
| 1 | Hillman Power Company LLC | Biomass | 18 | 135,550 | Twelve-month rolling average cost of CE coal generation | \$38.78 | 3.85¢/kWh On-Peak 3.27¢/kWh Off-Peak | 0.10¢/kWh | \$73.79 | \$10,002,823 | 12/31/2015 |
| 2 | Thornapple Association, Inc | Hydro | 1.4 | 6,548 | 3.30¢/kWh On-Peak 2.59¢/kWh Off-Peak | \$33.28 | 3.35¢/kWh On-Peak 2.85¢/kWh Off-Peak | 0.10¢/kWh | \$63.96 | \$418,791 | 12/31/2016 |
| 3 | White's Bridge Hydro Company | Hydro | 0.75 | 3,759 | Twelve-month rolling average cost of CE coal generation | \$38.92 | 3.76¢/kWh On-Peak 3.20¢/kWh Off-Peak | 0.10¢/kWh | \$73.36 | \$275,723 | 12/31/2016 |
| 4 | Black River Limited Partnership | Hydro | 1 | 3,780 | Twelve-month rolling average cost of CE coal generation | \$38.52 | 2.09¢/kWh On-Peak 1.78¢/kWh Off-Peak | 0.125¢/kWh | \$57.53 | \$217,498 | 12/31/2017 |
| 5 | Commonwealth Power Company – LaBarge | Hydro | 0.7 | 4,525 | Twelve-month rolling average cost of CE coal generation | \$39.06 | 4.45¢/kWh On-Peak 3.90¢/kWh Off-Peak | 0.10¢/kWh | \$80.14 | \$362,607 | 12/31/2017 |
| 6 | STS Hydropower Ltd – Fallasburg Hydro Plant | Hydro | 0.9 | 5,719 | 3.30¢/kWh On-Peak 2.59¢/kWh Off-Peak | \$33.27 | 3.09¢/kWh On-Peak 2.63¢/kWh Off-Peak | 0.10¢/kWh | \$61.58 | \$352,155 | 12/31/2017 |
| 7 | Grenfell Hydro, Inc (Belding) | Hydro | 0.3 | 1,865 | Twelve-month rolling average cost of CE coal generation | \$39.02 | 4.02¢/kWh On-Peak 3.42¢/kWh Off-Peak | 0.10¢/kWh | \$75.83 | \$141,412 | 12/31/2018 |
| 8 | Michiana Hydroelectric Co Bellevue | Hydro | 0.08 | 265 | Twelve-month rolling average cost of CE coal generation | \$39.16 | 5.36¢/kWh On-Peak 4.76¢/kWh Off-Peak | 0.10¢/kWh | \$89.42 | \$23,714 | 12/31/2018 |
| 9 | STS Hydropower Ltd – Cascade Hydro Plant | Hydro | 1.4 | 8,165 | 3.30¢/kWh On-Peak 2.59¢/kWh Off-Peak | \$33.30 | 4.25¢/kWh On-Peak 3.61¢/kWh Off-Peak | 0.10¢/kWh | \$72.20 | \$589,526 | 12/31/2018 |
| 10 | Viking Energy of Lincoln Limited Partnership | Biomass | 16.3 | 144,866 | Twelve-month rolling average cost of CE coal generation | \$38.84 | 4.30¢/kWh On-Peak 3.66¢/kWh Off-Peak | 0.10¢/kWh | \$78.18 | \$11,326,133 | 12/31/2018 |

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| Consumers Energy PURPA Contracts | | | | | | | | | | | |
|----------------------------------|--|----------------------|-------------|-----------|---|---|---|---|------------------------|---------------|---------------------------|
| Line No. | Generator | Technology Type | Capacity MW | 2014 MWh | Energy | 2014 Actual Variable Energy Cost \$/MWh | Capacity | Administrative Charge | 2014 Total Cost \$/MWh | 2014 Total \$ | Contract Termination Date |
| 11 | Viking Energy of McBain Limited Partnership | Biomass | 16.3 | 142,677 | Twelve-month rolling average cost of CE coal generation | \$38.86 | 4.30¢/kWh On-Peak 3.66¢/kWh Off-Peak | 0.10¢/kWh | \$78.20 | \$11,156,645 | 12/31/2018 |
| 12 | STS Hydropower Ltd – Morrow Hydro Plant | Hydro | 0.8 | 4,483 | 3.30¢/kWh On-Peak 2.59¢/kWh Off-Peak | \$33.26 | 3.97¢/kWh On-Peak 3.37¢/kWh Off-Peak | 0.10¢/kWh | \$69.50 | \$311,787 | 12/31/2019 |
| 13 | Kent County | MSW | 18 | 100,834 | Twelve-month rolling average cost of CE coal generation | \$39.31 | 5.34¢/kWh On-Peak 4.54¢/kWh Off-Peak | 0.10¢/kWh (not to exceed \$2,000/month) | \$88.06 | \$8,879,269 | 2/11/2022 |
| 14 | Boyce Hydro: Sanford Dam Edenville Dam Secord Dam Smallwood Dam | Hydro | 11 | 34,693 | 4.67¢/kWh On-Peak 3.66¢/kWh Off-Peak | \$44.33 | 2.33¢/kWh On-Peak 1.97¢/kWh Off-Peak | None | \$65.34 | \$2,266,751 | 5/31/2022 |
| 15 | Beaverton, City of | Hydro | 0.5 | 2,855 | 3.30¢/kWh On-Peak 2.59¢/kWh Off-Peak | \$33.27 | 3.51¢/kWh On-Peak 2.75¢/kWh Off-Peak | 0.10¢/kWh | \$64.08 | \$182,955 | 12/31/2023 |
| 16 | Midland Cogeneration Venture Limited Partnership | Co-Gen | 1,240 | 2,384,059 | Cost of Production | \$52.43 | 1.014¢/kWh | 0.10¢/kWh (not to exceed \$2,000/month) | \$125.76 | \$299,821,614 | 3/16/2025 |
| 17 | T.E.S. Filer City Station Limited Partnership | Multiple Coal, Wood, | 50 | 499,256 | Twelve-month rolling average cost of CE coal generation | \$39.52 | 6.24¢/kWh On-Peak 5.30¢/kWh Off-Peak | 0.10¢/kWh (not to exceed \$2,000/month) | \$84.47 | \$42,170,565 | 6/17/2025 |
| 18 | Ada Cogeneration Ltd Partnership | Co-Gen | 30 | 202,738 | Twelve-month rolling average cost of CE coal generation | \$32.24 | 4.024¢/kWh On-Peak 3.822¢/kWh Off-Peak | Administrative Charge: 0.10¢/kWh (not to exceed \$2,000/month) | \$86.83 | \$17,604,385 | 1/5/2026 |
| 19 | Granger Electric of Byron Center | Landfill Gas | 3.2 | 24,252 | Twelve-month rolling average cost of CE coal generation | \$32.79 | 4.184¢/kWh On-Peak 3.970¢/kWh Off Peak | 0.10¢/kWh (minimum of \$258/month, but not to exceed \$2,576/month) | \$79.48 | \$1,927,556 | 4/10/2026 |

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| Consumers Energy PURPA Contracts | | | | | | | | | | | |
|---|--|-----------------|-------------|---------------|---|---|--|---|------------------------|---------------|---------------------------------------|
| Line No. | Generator | Technology Type | Capacity MW | 2014 MWh | Energy | 2014 Actual Variable Energy Cost \$/MWh | Capacity | Administrative Charge | 2014 Total Cost \$/MWh | 2014 Total \$ | Contract Termination Date |
| 20 | <i>WM Renewable Energy, LLC. (formerly Bio Energy Partners) May be Venice Park</i> | Landfill Gas | 1.5 | Approx 11,826 | Twelve-month rolling average cost of CE coal generation | \$32.59 | 4.19¢/kWh On-Peak 3.98¢/kWh Off-Peak | 0.10¢/kWh (minimum of \$200/month, but not to exceed \$2,000/month) | \$79.50 | \$941,125 | 5/4/2027 |
| 21 | Grayling Generating Station Limited Partnership | Biomass | 36.17 | 198,262 | Twelve-month rolling average cost of CE coal generation | \$33.14 | 4.18¢/kWh On-Peak 3.97¢/kWh Off-Peak | 0.10¢/kWh (minimum of \$346/month, but not to exceed \$3,464/month) | \$104.58 | \$20,734,954 | 12/31/2027 |
| 22 | Granger Electric of Pinconning | Landfill Gas | 3.2 | 17,736 | Twelve-month rolling average cost of CE coal generation | \$32.39 | 4.348¢/kWh On-Peak 4.136¢/kWh Off Peak | 0.10¢/kWh (minimum of \$236/month, but not to exceed \$2,357/month) | \$81.17 | \$1,439,669 | 1/22/2028 |
| 23 | <i>Cadillac Renewable</i> | Biomass | 34 | 175,400 | <i>Not included on Exhibit A-3 U-17678</i> | \$32.88 | <i>Not included on Exhibit A-3 U-17678</i> | <i>Not included on Exhibit A-3 U-17678</i> | \$101.90 | \$17,872,880 | 2028 According to Cadillac RE Website |
| 24 | Granger Electric Company – Ottawa | Landfill Gas | 4.57 | 29,380 | Twelve-month rolling average cost of CE coal generation | \$32.60 | 4.374¢/kWh On-Peak 4.155¢/kWh Off-Peak | 0.10¢/kWh (minimum of \$346/month, but not to exceed \$3,464/month) | \$81.31 | \$2,388,712 | 6/21/2029 |
| 25 | Granger Electric Company – Grand Blanc | Landfill Gas | 3.81 | 22,008 | Twelve-month rolling average cost of CE coal generation | \$32.62 | 4.402¢/kWh On-Peak 4.182¢/kWh Off-Peak | 0.10¢/kWh (minimum of \$346/month, but not to exceed \$3,464/month) | \$81.62 | \$1,796,313 | 7/27/2029 |
| 26 | Adrian Energy Associates | Co-Gen | 2.4 | 17,678 | Twelve-month rolling average cost of CE coal generation | \$38.86 | 4.476¢/kWh On-Peak 4.253¢/kWh Off-Peak | Administrative Charge: 0.10¢/kWh (not to exceed \$2,000/month) | \$82.34 | \$1,455,611 | 12/13/2029 |
| 27 | C&C Energy, formerly Gas Recovery Systems | Landfill Gas | 2.75 | 13,679 | Twelve-month rolling average cost of CE coal generation | \$32.46 | 4.374¢/kWh On-Peak 4.155¢/kWh Off-Peak | 0.10¢/kWh (minimum of \$346/month, but not to exceed \$3,464/month) | \$81.29 | \$1,111,914 | 2/20/2030 |
| 28 | Commonwealth Power Company – Irving | Hydro | 0.6 | 2,352 | Twelve-month rolling average cost of CE coal generation | \$40.86 | 4.034¢/kWh On-Peak 3.832¢/kWh Off-Peak | 0.10¢/kWh (not to exceed \$2,000/month) | \$71.95 | \$169,198 | 8/25/2030 |

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| Consumers Energy PURPA Contracts | | | | | | | | | | | |
|---|---|-----------------|-------------|-----------|---|---|---|---|------------------------|---------------|---------------------------|
| Line No. | Generator | Technology Type | Capacity MW | 2014 MWh | Energy | 2014 Actual Variable Energy Cost \$/MWh | Capacity | Administrative Charge | 2014 Total Cost \$/MWh | 2014 Total \$ | Contract Termination Date |
| 29 | North American Natural Resources, Inc.- (Peoples) | Landfill Gas | 3.2 | 17,659 | Twelve-month rolling average cost of CE coal generation | \$32.72 | 4.374¢/kWh On-Peak 4.155¢/kWh Off-Peak | 0.10¢/kWh (minimum of \$346/month, but not to exceed \$3,464/month) | \$81.41 | \$1,437,616 | 9/8/2030 |
| 30 | Michigan Power Limited Partnership | Co-Gen | 123 | 1,010,269 | Twelve-month rolling average cost of CE coal generation | \$39.78 | 3.880¢/kWh On-Peak 3.686¢/kWh Off-Peak | 0.10¢/kWh (not to exceed \$2,000/month) | \$77.40 | \$78,195,962 | 10/23/2030 |
| 31 | Granger Electric Company – Seymour | Landfill Gas | 0.75 | 5,980 | Twelve-month rolling average cost of CE coal generation | \$32.88 | 4.374¢/kWh On-Peak 4.155¢/kWh Off-Peak | 0.10¢/kWh (minimum of \$346/month, but not to exceed \$3,464/month) | \$81.73 | \$488,742 | 11/21/2030 |
| 32 | Genesee Power Station Limited Partnership | Biomass | 35 | 151,014 | Twelve-month rolling average cost of CE coal generation | \$31.64 | 4.65¢/kWh On-Peak 4.42¢/kWh Off-Peak | 0.10¢/kWh (minimum of \$200/month, but not to exceed \$2,000/month) | \$126.35 | \$19,080,740 | 12/13/2030 |
| 33 | Commonwealth Power Company – Middleville | Hydro | 0.35 | 1,496 | Twelve-month rolling average cost of CE coal generation | \$39.61 | 4.034¢/kWh On-Peak 3.832¢/kWh Off-Peak | 0.10¢/kWh (not to exceed \$2,000/month) | \$76.40 | \$114,415 | 1/1/2031 |
| Contract information compiled by MPSC Staff from Consumers Energy's PSCR Plan Case and Act 295 Annual Report. | | | | | | | | | | | |

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DTE PURPA Contracts

| Line No. | Generator | Technology Type | Capacity MW | 2014 MWh | Contract Termination Date |
|----------|---|-----------------|-------------|----------|---------------------------|
| 1 | Riverview Energy Systems | LFG | 5.4 | 46,431 | 2023 |
| 2 | Greater Detroit Resource Recover Facility | MSW | 70 | 272,996 | 6/30/2024 |
| 3 | Wayne Energy Recovery | LFG | 1.2 | 3,181 | 2027 |
| 4 | Ford Lake Hydroelectric Station | Hydro | 1.92 | 9,843 | 2028 |
| 5 | Turbine Power Limited Partnership - Arbor Hills | LFG | 17.3 | 124,546 | 2031 |
| 6 | Pine Tree Acres | LFG | 8.6 | 72,359 | 2033 |
| 7 | Sumpter Energy Associates - City Sand | LFG | 11.8 | 7,410 | 2033 |
| 8 | Sumpter - Carleton Farms Phase 1 | LFG | 6.4 | 46,798 | 2033 |
| 9 | Sumpter - Carleton Farms Phase 2 | LFG | 5.6 | 34,863 | 2033 |
| 10 | Superior Dam | Hydro | 0.6 | 2,706 | 2036 |
| 11 | Barton Dam | Hydro | 0.9 | 5,926 | 2036 |
| 12 | French Landing Dam | Hydro | 1.8 | 8,323 | 2039 |

Contract information compiled by MPSC Staff from DTE's PSCR plan case, DTE Staff and Act 295 annual report.

A CMS Energy Company

February 23, 2016

Michigan Public Service Commission
Attn: Mr. Paul Proudfoot, Director – Electric Reliability Division
7109 W. Saginaw Highway
Lansing, MI 48917

David F. Ronk Jr.
Executive Director
Electric Transactions
and Wholesale Settlements

Dear Mr. Proudfoot,

On February 10, 2016, the Michigan Public Service Commission (MPSC) Staff conducted a meeting to discuss a proposed methodology for the calculation of utility avoided cost as part of the Public Utility Regulatory Policies Act of 1978 (PURPA) technical advisory committee. At the conclusion of the meeting you requested that all interested parties provide comments on the proposed methodology in writing by February 24, 2016. In addition to comments on the proposed methodology, Consumers Energy provides responses to several questions and discussions that arose at the February 10, 2016 meeting.

MPSC Staff's Proposed Methodology:

MPSC Staff proposed a standard methodology to establish the avoided cost to be paid to a Qualifying Facility (QF) based on the Capacity Cost associated with a Combustion Turbine (CT) and the Energy Cost resulting from: (a) either: (i) the Locational Marginal Price (LMP) as determined by Midcontinent Independent System Operator, Inc. (MISO); (ii) levelized LMP; or (iii) levelized Natural Gas Combined Cycle (NGCC) plant variable costs; and (b) a NGCC Energy Price Adjustment. MPSC Staff's proposed method incorporates several concepts that the Company supports. However, MPSC Staff's proposal is unlikely to adequately reflect a utility's avoided cost at all times and requires additional flexibility to accommodate the different planning horizons ahead. The following comments are provided to assist in modifying MPSC Staff's proposal to provide that flexibility.

Identifying Need:

A utility's avoided cost is highly dependent on the utility's capacity need. At Consumers Energy we put a significant emphasis on meeting customer demands using the lowest cost resources available. In support of this endeavor, Consumers Energy has different strategies for meeting capacity shortfalls depending on the size of the shortfall. As a result, the method used to determine the avoided costs that should be paid to a QF will vary significantly depending on the capacity need in a given year. Consumers Energy proposes the following tiered approach to determining avoided costs based on the utility's need for capacity over the planning horizon:

- 1) For those periods when the Capacity Need is expected to be less than zero (0) Zonal Resource Credits (ZRCs), we propose that the methodology recognize that no capacity payment is avoided and that the avoided energy payment is equal to LMP.
- 2) For those periods when the Capacity Need is greater than zero (0) ZRCs but less than 200 ZRCs the avoided capacity cost should be based on MISO's Planning Resource Auction (PRA) and the avoided energy payment should be equal to LMP.
- 3) For those periods when the Capacity Need is greater than 200 ZRCs but less than 1000 ZRCs the avoided Capacity Payment should be based on CT fixed costs, and the avoided energy payment equal to lesser of CT variable cost and LMP.
- 4) For those periods when the Capacity Need is greater than 1000 ZRCs the avoided Capacity Payment should be based on NGCC fixed costs, and the avoided energy payment equal to lesser of NGCC variable costs and LMP.

Capacity Component:

First, in order to consider various capacity options on a comparable basis and allow for the tiered capacity payments discussed above, MPSC Staff's methodology should consider the economic carrying charge associated

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with the avoided proxy plant. The use of economic carrying charge ensures that payments made in a given year represent the appropriate value received for the capacity in that year. The use of a levelized cost would result in “front loading” compensation. Use of levelized costs require: (i) the same avoided proxy plant is used; (ii) the term of the contract covers the entire life of the proxy plant; and (iii) deliveries commence at the same time for all contracts compensated under those rates, regardless of the utility’s need for capacity. Use of the economic carrying charge allows for flexibility in the payments and would enable the tiered approach Consumers Energy is advocating.

Second, Consumers Energy only realizes the benefit of a generator’s capacity to the extent that MISO recognizes the resource as capable of delivering capacity directly to the grid or through modification of a market participant’s load. To accomplish this, MISO awards ZRCs to all registered generators. Consumers Energy currently receives ZRCs for all existing QFs for which it pays for capacity. These ZRCs are determined through various rules that are established in MISO’s Business Practice Manuals (BPMs). Payment for capacity must tie back, in some fashion, to the amount of ZRCs received, or expected to be received, from a given generator. For example, if the avoided plant is considered a CT, the investment is made with an expectation of a given performance and resulting ZRCs. Using MISO’s current rules, Consumers Energy would expect to initially receive 0.9431 ZRCs for every MW of capacity verified through an appropriate capacity test. To the extent that an existing generator receives more or less ZRCs per verified MW of capacity, that should be reflected in the payments to that generator. This is best accomplished by determining the appropriate \$/ZRC-Year payment rate for the avoided plant and providing payment to QFs based on the number of ZRCs QF is able to supply through MISO’s resource adequacy procedures for determining annual unforced capacity. Annual capacity value should be allocated into monthly payment amounts. That way, customers pay for the capacity commensurate with when it is used and costs are recovered across the two PSCR years in which they occur (since the MISO capacity planning year runs from June 1 through May 31 of the following year).

Energy Component:

Use of the LMP in determining the energy component is critical.

First, the LMP truly represents the avoided cost of energy to the utility. Absent the delivery of energy from a QF, Consumers Energy would either (i) lose the revenue associated with a sale occurring at the LMP, (ii) increase purchases being made at the LMP, or (iii) some combination of both. If Consumers Energy actually built the avoided plant, its customers would receive the net energy value (NEV) associated with operation of the plant in the market. Therefore, it is important that the energy component be modified appropriately to reflect the NEV that would have been received if the utility had constructed the avoided plant.

Second, the use of actual LMP, capped at the appropriate avoided plant variable cost, ensures that QFs receive the appropriate economic signals. Consumers Energy’s participation in MISO gives our customers access to the lowest cost generation resources in the midcontinent region. Consumers Energy identifies the costs for generating electricity at its facilities and offers those costs in the form of an asking price into to the MISO energy market. To the extent that lower cost options are available, MISO provides signals to have the lower cost generator produce energy and reduces the output from Consumers Energy’s generators. The MISO energy market relies on the LMP to provide these signals. By leveraging the LMP for avoided cost payments, Consumers Energy’s customers are ensured that QFs are incented to produce the maximum amount of energy possible when it produces the most value and the minimum amount of energy possible when it produces the least value.

Some QFs may assert that they cannot be dispatched to higher and lower output levels due to the technology of their facility. Paying the QF the lower of the avoided plant’s cost of production or the MISO LMP takes this factor into account so that the cost to customers is effectively the same as it would have been had the utility constructed the plant and fully dispatched it according to MISO energy market price signals. The QF can run as much as or as little as it wants, getting paid based on the energy it produces at the prices determined through this guideline.

NGCC Energy Adjustment:

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For the same reasons discussed above, there is no need for the NGCC Energy Adjustment payment as it is included, if justified, in the payments made based on the capacity need. The NGCC Energy Adjustment, therefore, should be eliminated. This simplifies the calculation of avoided costs significantly. First, it eliminates the need to use the fixed costs for two different generation technologies in determining avoided costs for a given year. Second, there is no need to convert fixed costs into a volumetric value. Conversion of fixed costs to volumetric costs would be highly dependent on the assumed operating characteristics of the NGCC plant and market price forecasts. Relying on the appropriate fixed costs and the lesser of actual LMP and avoided variable costs is much simpler and will deliver the same value as using an NGCC energy adjustment payment. Additionally, using actual LMP will take forecasting the future out of the equation, and ensure customers only pay for actual avoided energy costs.

General Comments:

Consumers Energy has concerns regarding the table provided on the last page of MPSC Staff's avoided cost presentation. The presentation of the proposed methodology in that table creates the impression that a fixed \$/MWh amount will be agreed to and paid to QFs for each MWh of energy produced. Avoided costs should be presented as they will be paid, based on a combination of capacity (a fixed monthly payment based on the ZRCs supplied by the QF) and energy (a volumetric monthly payment based on actual energy delivered). If illustrations are necessary to ensure all parties understand the proposal, it should be clearly laid out using a series of hypothetical scenarios based on real world data for various generators.

Questions to Consider:

On February 10, 2016, MPSC Staff presented several "Questions to consider." Consumers Energy offers the following responses:

1. Q: Should capacity be paid hourly, monthly, yearly and if the latter two, should there be a true up?
A: Capacity can be paid on any mutually agreed upon time frame (although a monthly settlement would be the most appropriate), but should be based on the ZRCs received within the MISO construct. The use of a payment(s) based on ZRCs would eliminate the need for any true up because they are awarded, based on the MISO rules, in advance of and for the entire capacity season.
2. Q: Should capacity be discounted by ELCC?
A: Capacity should be reflective of the Effective Load Carrying Capability (ELCC) of the resource. By basing payments on ZRCs received, ELCC is applied as appropriate for all technologies.
3. Q: Should capacity be reduced to 75% of the full amount to account for "all or nothing" capacity need cycles?
A: Given that the proposed methodology is not attempting to represent the MISO capacity market construct, it would be inappropriate to apply the 75% concept. If the intent were to reflect a forecast of the MISO market value of capacity, then applying the 75% concept to the calculated Cost of New Entry (CONE) would be an approach to capture the "all or nothing" nature of the MISO market construct.
4. Q: Should LMPs be actual average hourly/monthly or should a projection be used and should there be a true up?
A: As discussed above, the use of actual LMPs (capped at the variable cost of a CT or NGCC plant, if and as applicable) would represent the best avoided cost and provide the appropriate market signals to the QFs. Projected costs carry significant risk for both customers and the QF. A true up mechanism could be used in concert with projected costs; however using actual LMPs would probably be just as efficient. We should all remember that it is the customer that pays for these costs. Using actual LMPs ensures customers pay no more and no less than the true avoided cost of energy for the utility.
5. Q: Who should own the RECs/CO2 attributes and if IPPs own RECs/CO2 attributes should there be a utility obligation to purchase?

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A: RECs should belong to the utility. The reason a utility has a must purchase obligation is because of the use of “qualifying” technology. To the extent that a facility qualifies because it is renewable, the utility should receive the RECs. Regarding CO2 attributes, there is substantial uncertainty how current proposed rules will be implemented, therefore, to the extent that the utility’s purchase from a QF results in additional carbon emissions that the utility would otherwise avoid or additional energy expense, the utility should be awarded the carbon allowances.

Term:

It is impossible to understand what the future may hold. Changes in regulation, technology, economic development, and many other factors drive our business and the cost of producing energy. Changes in any of these factors can quickly make the terms of a very appealing contract turn sour. In order to minimize the risk to our customers of significantly over-market obligations, we must limit the term-length of all PURPA avoided cost contracts. The more market based the methodology, the more comfortable Consumers Energy is with longer-term agreements. For example, under a methodology that simply passed actual market rates for energy and capacity onto QFs, a long-term contract would be acceptable. Under a methodology where compensation rates must be fixed at the time of contract execution, Consumers Energy advocates for terms of 5 years or less in length.

Administrative Process:

During the February 10, 2016 meeting, discussion arose regarding the necessity of having separate contested case proceedings for approval of each PPA entered into between the utility and a QF. Consumers Energy recommends that the Commission approve these contracts on an *ex parte* basis. Since each utility’s avoided costs will be determined in a contested case before the MPSC, it would be an inefficient use of the MPSC’s resources to re-litigate the utility’s previously established avoided costs when reviewing and approving the PPA. This is a similar approach to the approval of Renewable Energy Purchase Agreements under 2008 PA 295.

Conclusion:

Under MPSC Staff’s proposed avoided cost methodology as modified by these comments, ratepayers are ensured costs will never exceed those that would be incurred if the utility did not purchase the energy and capacity produced by a QF. This is in perfect harmony with PURPA. Regular filing with the MPSC on capacity needs and avoided costs will ensure that the appropriate payments are made to all QFs.

Respectfully,



David F. Ronk, Jr.
Executive Director – Transactions and Wholesale Settlements

February 24, 2016

Submitted Via E-mail Only.

Michigan Public Service Commission Staff
7109 W. Saginaw Hwy., 3rd Floor
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harlowj@michigan.gov

Commission Staff:

The Environmental Law and Policy Center (“ELPC”) and 5 Lakes Energy hereby submit the following comments in response to the Staff Strawman Proposal regarding the methodology for establishing avoided costs under the Public Utility Regulatory Policies Act of 1978, Pub. L. No. 95-617, 92 Stat 3117 (“PURPA”).

I. Introduction

On October 27, 2015, the Michigan Public Service Commission (“Commission”) issued an order commencing investigation into PURPA and the avoided cost payments that a public utility may be obligated to pay to a Qualifying Facility (“QF”).¹ In its Opening Order, the Commission noted that the passage of time and significant changes in the energy industry merited a comprehensive examination of PURPA and avoided cost issues. One of these changes is the increased availability of renewable energy.

By the Commission’s order, a Technical Advisory Committee (“TAC”) was established consisting of Staff, representatives of electric utilities and electric cooperatives, QFs, small power producers, and advocates. ELPC and 5 Lakes Energy appreciate the opportunity to be involved in the TAC and to provide comments responsive to the straw man proposal created by Staff. The Strawman Proposal includes preliminary avoided cost calculations for five different methodologies: Hydro, Biomass, Landfill Gas, Solar, and Wind. The avoided cost for each of these technologies must be fair and non-discriminatory, which requires an evaluation of the specific characteristics of the type of renewable generation. While ELPC and 5 Lakes Energy’s comments support a robust avoided cost methodology for all QFs, we provide specific analysis related to solar and co-generation. ELPC and 5 Lakes Energy have participated in working groups established by the Commission addressing the characteristics of solar generation; these comments are a natural extension of that work. Other participants in the TAC have focused on

¹ Case No. U-17973, Dkt. #1, (Mich. PSC 2015).

the specific attributes of other renewable technologies which should also be given full and careful consideration in establishing avoided cost rates.

II. The Strawman Proposal Methodology Should Be Expanded To Calculate The Utility's Full Avoided Cost, Taking Into Account Technology-Specific Values.

In order to encourage the development of co-generation and small power production facilities, Section 210 of PURPA requires large electric utilities to purchase available energy and capacity from small power producers, known as “qualifying facilities”.² The Federal Energy Regulatory Commission (“FERC”) has delegated to state commissions the responsibility to set rates for purchases from qualifying cogenerators and small power producers by electric utilities under their ratemaking authority.³ In doing so, FERC stated that it “believe[d] that providing an opportunity for experimentation by the States is more conducive to the development of these difficult rate principles.”⁴

PURPA leaves the specific methodology to be used in determining avoided cost to the states’ discretion.⁵ In Michigan, where the state legislature has not mandated the use of a particular avoided cost methodology, the appropriate methodology is left to the Commission.

PURPA requires that rates for the purchase of energy from QFs not discriminate against qualifying cogenerators or qualifying small power producers and be just and reasonable to the consumers of the electric utility and in the public interest.⁶ Under FERC’s implementing regulations, upheld by the U.S. Supreme Court in 1983, avoided cost rates are set at the utility’s **full avoided cost**.⁷ Under these regulations, a utility’s full avoided cost is the incremental cost the utility would bear if it were required itself to supply or purchase the electricity produced by the small power producer.⁸

Neither PURPA nor its implementing regulations support the interpretation of avoided cost as the price of energy on the spot market or the short-term marginal cost to the utility of generating one additional unit of electric energy. To the contrary, PURPA encourages states to look beyond the cost of “alternative sources which are instantaneously available to the utility” and evaluate factors such as the reliability of the power and cost savings that could accrue to the

² See 16 U.S.C. § 824a-3 (2005); *American Paper Inst. v. Am. Elec. Power Serv. Corp.*, 461 U.S. 402, 405 (1983) (“Section 210 of PURPA was designed to encourage the development of cogeneration and small power production facilities.”).

³ *State ex rel. Utilities Com’n v. North Carolina Power*, 450 S.E.2d 896, 899 (1994); see also *Small Power Production and Cogeneration Facilities Regulations Implementing Section 210 of PURPA* (Order No. 69), 45 Fed. Reg. 12214, 12215 (Feb. 25, 1980).

⁴ *Id.* at 12231.

⁵ See *California Public Utilities Com’n Order Denying Rehearing*, 134 FERC ¶ 61,044, 61,160 (2011) (granting state commissions the authority to decide what particular capacity is being avoided in setting avoided cost rates).

⁶ See 16 U.S.C. § 824a-3(b) (2005); 18 C.F.R. § 292.304(a)(1) (2015).

⁷ See *American Paper Inst.*, 461 U.S. 402 (1983).

⁸ See *Public Service Co. v. Public Utilities Com.*, 687 P.2d 968, 973 (Colo. 1984); 18 C.F.R. § 292.304(b) and (e).

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utility in the future.⁹ In order to be just and reasonable, the avoided cost rate does not need to be set at the lowest possible rate available.¹⁰

FERC explicitly sets out those factors that must, to the extent practicable, be taken into account when determining avoided costs. These factors should be evaluated in light of the underlying purpose of PURPA. As the Court explained in *FERC v. Mississippi*, “Congress believed that increased use of these sources of energy would reduce the demand for traditional fossil fuels,” and it recognized that electric utilities had traditionally been “reluctant to purchase power from, and to sell power to, the nontraditional facilities.”¹¹ The factors that must be considered are:

- (1) [Utility system cost] data provided pursuant to § 292.302(b), (c), or (d), including State review of any such data;
- (2) The availability of capacity or energy from a qualifying facility during the system daily and seasonal peak periods, including:
 - (i) The ability of the utility to dispatch the qualifying facility;
 - (ii) The expected or demonstrated reliability of the qualifying facility;
 - (iii) The terms of any contract or other legally enforceable obligation, including the duration of the obligation, termination notice requirement and sanctions for non-compliance;
 - (iv) The extent to which scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the utility’s facilities;
 - (v) The usefulness of energy and capacity supplied from a qualifying facility during system emergencies, including its ability to separate its load from its generation;
 - (vi) The individual and aggregate value of energy and capacity from qualifying facilities on the electric utility’s system; and
 - (vii) The smaller capacity increments and the shorter lead times available with additions of capacity from qualifying facilities; and
- (3) The relationship of the availability of energy or capacity from the qualifying facility as derived in paragraph (e)(2) of this section, to the ability of the electric utility to avoid costs, including the deferral of capacity additions and the reduction of fossil fuel use; and
- (4) The costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a qualifying facility, if the

⁹ See *Public Service Co.*, 687 P.2d at 973 (Colo. 1984)(citing H.R. Conf. Rep. No. 95-1750, 95th Cong., 2d Sess., reprinted in 1978 U.S.C.C.A.N. 7797, 7832-33).

¹⁰ See *American Paper Inst.*, 461 U.S. 413, 414 (1983).

¹¹ *FERC v. Mississippi*, 456 U.S. 751 (1982) (footnote omitted).

purchasing electric utility generated an equivalent amount of energy itself or purchased an equivalent amount of electric energy or capacity.¹²

Commission Staff's Strawman Proposal properly takes into account both energy and capacity impacts on avoided costs on a technology-specific basis. ELPC supports the Strawman Proposal's technology-specific methodology and further notes that a 2010 FERC ruling confirmed that avoided cost rates can differentiate among QFs using various technologies on the basis of the supply characteristics of the different technologies.¹³ Avoided cost methodology should differ by technology, because each of the available technologies has different attributes that impact avoided cost in different ways. However, the methodology must be non-discriminatory and result in a full and fair avoided cost rate for each of the different methodologies.

Staff raised a number of additional questions and issues for discussion in the TAC that acknowledge the factors outlined in the FERC implementing regulations. The Commission must now explicitly include each of these factors into technology-specific avoided cost methodology. It is not only practicable to include each of these factors into the avoided cost methodology, but as discussed below, it is the trend in other states that are undertaking similar evaluations of avoided costs under PURPA.

a. Effective Load Carrying Capacity

We appreciate and support Staff's proposal to base capacity value on effective load-carrying capacity (ELCC). This is the appropriate way to determine the effect on firm capacity requirements of resource-limited QFs such as solar, hydropower, and cogeneration. However, we urge staff to recognize that effective load-carrying capacity is potentially facility-specific and technology-dependent. Given a fixed solar array facing south, a fixed solar array facing southwest, a single-axis tracking solar array, and a dual-axis tracking array, each will have a different ELCC. A cogeneration facility that operates whenever the host facility needs process heat will likely have an ELCC that is nameplate capacity less its forced outage rate, which according to Oak Ridge National Laboratory can be as low as 2.5%, while a dispatchable cogeneration facility may also fail to produce due to low spark spread. Thus, while we support use of technology-average ELCC as a starting point in the Commission's methodology, we also urge room for case-specific determination.

With specific respect to solar QFs, we note that the ELCC calculation methods commonly used by utilities and RTOs fail to account for the fact that solar generation is specifically correlated with peak loads because solar heat gain during times of high insolation causes a part of peak loads. Typical averaging methods miss this phenomenon. While we do not expect the Commission to overcome this deficiency and use capacity credits that would not be accepted by regional transmission organizations ("RTOs"), the Commission should understand that it will be undervaluing solar capacity by using these methods.

¹² 18 C.F.R. § 292.304(e)(1)-(4).

¹³ See Order Granting Clarification and Dismissing Rehearing, 133 FERC ¶ 61,059 (Oct. 21, 2010).

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We further note that if a QF is required to purchase stand-by capacity against the potential that the QF will not be generating at all times, then the QF is effectively providing 100% capacity through the bundle of QF operations and standby power agreements; therefore, the QF should accordingly be credited for said capacity.

b. Avoided Transmission Costs

With respect to all generation technologies, the Commission must include appropriate treatment of avoided transmission costs in its methodology. Michigan regulated electric utilities do not directly own or operate transmission facilities, but purchase transmission services through either the Midcontinent Independent System Operator (“MISO”) or PJM Interconnection (“PJM”), pursuant to tariffs adopted by those organizations and approved by FERC. Most costs of transmission are broadly “socialized” within the footprints of these RTOs and are allocated to individual utilities based on the twelve monthly peak hours of power delivery to step-down substations in each utility’s service territory. Thus, any QF that is interconnected at sub-transmission voltage and whose power output partially or fully reduces power delivery from the transmission system to such a substation during monthly peak hours directly reduces transmission charges to its utility. This reduction constitutes an avoided cost to the utility, one that the Commission must determine and consider as an avoided cost. The amount of such avoided cost will necessarily be based on the specific circumstances of the QF, but the method of determination can be addressed now by the Commission.

In addition to this basic allocation of transmission costs to utilities, at certain times (not necessarily at monthly peak hours) transmission congestion charges are allocated to a utility when power cannot be delivered to a substation from the least-cost generation resource due to constraints in the transmission system. Specific substations may experience congestion charges at high frequency or in high amounts. These congestion charges are intended to provide a market signal as to the need for additional transmission capacity or alternative resources such as load reduction or distributed generation. A QF that is interconnected through such a substation will reduce such congestion charges, and the Commission must determine either that any avoided congestion charges are an avoided cost to the utility or that any deferred or avoided capacity investments are an avoided cost to the utility. In certain circumstances where transmission congestion, substation capacity, or line length and load prevent the utility from delivering adequate voltage to customers on the same distribution circuits as the QF, the avoided transmission cost may take the form of improved service to those other customers and this should be accounted for as an avoided cost. The amount of such avoided cost will necessarily be based on the specific circumstances of the QF but the method of determination can be addressed now by the Commission.

c. Avoided Line Losses

To the extent that any QF interconnected at sub-transmission voltage serves local load and does not place that power on the transmission system, it avoids line and transformer losses. Thus the value of energy and capacity provided by the QF should each be scaled by the appropriate line-loss factor. The Commission routinely considers and adopts line-loss factors in general rate cases and applies those line-loss factors in power supply cost recovery cases. At minimum, the Commission should use the most recent line-loss study of the relevant utility and make the appropriate adjustments to both energy and capacity avoided costs. It is important to

note that the line-loss factors for energy and capacity are distinct and separately determined. We further note that while it is Commission practice to use annual average line-loss factors in adjusting energy costs, actual physical losses are the sum of some losses in transformers and similar equipment that are constant with respect to current and a substantial majority of actual physical losses that are proportional to the square of current. Consequently, any marginal reduction of load due to distributed generation reduces losses equal to nearly twice the proportional reduction in load. Thus, if the Commission only applies the line-loss factors determined in its rate cases, it will systematically understate the avoided costs of distributed generation.

d. Hedging Value

Solar and other distributed generation provided through long-term QF contracts at a fixed price or price schedule also acts as a hedging mechanism, reducing a utility's fuel price uncertainty. This hedge has real value and should be included in avoided costs. The standard method to value such a hedge is to determine the levelized cost of the contracted power to the utility using a zero-risk discount rate, for which US treasury inflation-protected securities are normally the proxy. If the contract is indexed to a macroeconomic measure, such as general inflation, then the discount rate used in the levelized cost calculation should be adjusted for the index. For example, if the contract is indexed to inflation then the discount rate should be based on (non-inflation-protected) US treasury securities.

e. Avoided Emissions and Environmental Compliance Costs

Utilities should also include avoided carbon costs and other emissions allowances in the calculation of avoided energy costs. While environmental considerations are not included in FERC's regulations, planning numbers associated with regulation of greenhouse gas emissions reflect imminently real, non-zero, costs. While there are challenges to quantifying this benefit, the value should not be set at zero. Unless such costs are quantified and included in the avoided costs on which a QF's contract is based, then the value of any such future avoided costs to the utility should accrue to the QF at such time as regulatory changes cause such costs to be manifest. Some care is needed on this point, as some environmental benefits, such as renewable energy credits, can accrue to the QF in the ordinary course of regulation. But others, such as avoidance of emissions allowances by utility generation, may accrue to the utility in the ordinary course of regulation.

III. The Commission Should Consider a Value of Solar Analysis to Help Establish Avoided Costs for Distributed Solar Resources in Michigan.

States and utilities are undertaking increasingly sophisticated evaluations of the true avoided cost of solar. These evaluations not only acknowledge the factors FERC requires be considered in determining avoided costs, but also demonstrate the feasibility of incorporating these factors into an avoided cost methodology that captures the full, technology-specific avoided costs of solar PV. Staff's 2014 Solar Working Group report discussed several programs that have attempted to establish a fair "value of solar" ("VOS") rate based on avoided utility costs, including the Austin Energy VOS Program, the Minnesota VOS methodology, a dynamic pricing program proposed by 5 Lakes Energy, and a Michigan-specific white paper developed by

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the National Renewable Energy Lab (NREL).¹⁴ The Solar Energy Industries Association (SEIA) maintains a webpage with links to more than 30 other recent solar cost-benefit studies.¹⁵

Although the details vary, the benefits and costs studied in VOS analysis generally fall into the following categories: energy (including line-losses), capacity (both generation capacity and transmission and distribution capacity), grid support services (also referred to as ancillary services), financial risk (fuel price hedging and market price response), security risk (reliability and resilience), environmental benefits (carbon emissions, criteria air pollutants, and others) and social benefits. Many of these values relate to solar generation's innate characteristics – its natural coincidence with peak demand; its ability to avoid transmission capacity costs and line-losses by siting smaller systems on the distribution grid closer to load; its scalability; its lack of fuel volatility; and other characteristics.

The growing body of VOS analysis consistently demonstrates that solar energy has value that significantly exceeds more narrowly calculated avoided costs. While not every factor can be quantified precisely, a VOS analysis generally provides a more accurate estimate of the “full avoided costs” associated with solar generation over the life of the solar generation system. Thus, several states and utilities have established or are considering the use of a VOS analysis to establish a technology-specific avoided cost under PURPA that explicitly accounts for the unique values of distributed solar PV.¹⁶

The firm Clean Power Research (CPR) has conducted a number of comprehensive market-based VOS studies that have been used by a number of states and utilities to help inform program and tariff design. CPR has just completed a new report that describes a proposed methodology and other recommendations for valuing distributed solar energy resources in Michigan.¹⁷ The report concludes that a properly-designed VOS analysis could be used to establish a technology-specific avoided cost for distributed PV resources in Michigan. The Commission should carefully consider this report, as well as the other VOS analyses performed for other states and utilities in order to develop a technology-specific rate that fairly reflects the “full avoided costs” associated with solar generation.

¹⁴ See Michigan Public Service Commission, *Solar Working Group – Staff Report* (June 30, 2014) available at <http://efile.mpsc.state.mi.us/efile/docs/17302/0106.pdf>. (The MPSC's Solar Working Group website also includes links to other value of solar (VOS) resources and documents. The website is available at the following link:

http://www.michigan.gov/mpsc/0,4639,7-159-16393_55246_55249-321593--,00.html).

¹⁵ See SEIA, *Distributed Solar Cost-Benefit Studies*, <http://www.seia.org/policy/distributed-solar/solar-cost-benefit-studies> (last visited Feb. 24, 2016).

¹⁶ For example, Georgia Power recently filed a new VOS framework that it intends to “serve as the basis for new avoided cost calculations, renewable program development, project evaluation, and rate design.” See Georgia Public Service Commission, Docket 40161 (Georgia Power Company's 2016 Integrated Resource Plan) at 10-103.

¹⁷ Clean Power Research, *PV Valuation Methodology, Recommendations for Regulated Utilities in Michigan* (February 2016) (attached as Exhibit 1).

IV. The Commission Should Consider Expanding the Availability of Standard Rates For Purchases to Further the Purposes and Objectives of PURPA.

In addition to creating an avoided cost methodology that encourages cogeneration and small power production facilities, the Commission must also evaluate the framework under which energy and capacity are provided by QFs. This framework must include the availability of standard rates to QFs that reduce transaction costs and are of sufficient length to provide certainty regarding financing. Long-term contracts enable investors to calculate return on investment with certainty and instill confidence that the borrower will be in a position to repay any loan extended. With increased price certainty for a project, investors typically require a lower return, which, in turn, reduces the cost of financing. Unlike the electric utilities to which they provide energy and capacity, a QF is not guaranteed a rate of return on its activities. Without some continuity and certainty, QFs are placed in a position of considerable risk in proceeding forward in a cogeneration or small power production enterprise.

The establishment of standard rates under PURPA provides the certainty necessary to encourage development of cogeneration and small power production facilities. PURPA regulations require electric utilities to establish standard rates for purchases from QFs with capacity of 100 kilowatts (“kW”) or less, and give state commissions the authority to develop standard rates for larger QFs.¹⁸ In contrast to an individualized rate, a standard rate is the avoided cost rate that would apply to any QF eligible for that rate that provides energy or capacity to the utility. The availability of a standard rate reduces transaction costs for individual QFs, avoiding the cost and burden of establishing an individualized avoided cost rate and reducing barriers to entry. Although standard rates do not differentiate among individual QFs, they can be technology-specific and “differentiate among qualifying facilities using various technologies on the basis of the supply characteristics of the different technologies.”¹⁹

Standard rates allow QFs to create a legally enforceable obligation on the part of the utility to purchase energy and capacity. Under a standard rate for purchases, a QF has the option to either provide energy “as available” or to provide energy or capacity pursuant to a legally enforceable obligation.²⁰ If the QF chooses to sell pursuant to a legally enforceable obligation, it has the express right to choose a rate based on either the avoided costs calculated at the time of delivery, or the avoided costs calculated at the time the obligation is incurred.²¹ FERC established this legally enforceable obligation in order to reconcile the requirement that rates for purchases equal avoided costs with the need for QFs to enter into contractual commitments based on estimates of future avoided costs. In promulgating regulations, FERC agreed with comments stressing the need for certainty with regard to return on investment in new technologies.²² Standard rates are essential for small QFs to obtain financing. FERC acknowledged that “in order to be able to evaluate the financial feasibility of a cogeneration or small power production

¹⁸ 18 C.F.R. § 292.304(c)(1), (2).

¹⁹ *Id.* at 292.304(c)(3)(ii).

²⁰ *Id.* at 292.304(d).

²¹ *Id.*

²² 45 Fed. Reg. 12224 (1980).

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facility, an investor needs to be able to estimate, with reasonable certainty, the expected return on a potential investment before construction of a facility.”²³

The mechanism is framed as a “legally enforceable obligation” in order to prevent utilities from circumventing the requirement that provides capacity credit for a QF simply by refusing to enter into a contract.²⁴ Intermittent QF resources, including solar, can enable a utility to avoid capacity, and the aggregate capacity value of such facilities must be considered in the calculation of rates for purchases.²⁵

Michigan should establish standard rates for QFs with generating capacity above 100 kW because it will further the purposes of PURPA by promoting growth of cogeneration and small power production facilities. In fact, the FERC gave states the discretion to establish standard rates for larger QFs **precisely because** standard rates significantly encourage cogeneration and small power production.²⁶ Other states have recognized the benefit of extending the standard rate to larger QFs. In upholding the propriety of continuing to offer standard rate contracts to QF’s under 5MW, the North Carolina Utilities Commission considered Public Staff testimony that:

. . . setting the standard threshold at a [5 MW] level that allows QFs to receive the benefit of reduced transaction costs and appropriate economies of scale provides ratepayers with the assurance that the utilities’ resource needs are being met by the lowest cost options that may be available.²⁷

Extending standard rates for larger QFs in Michigan will not only serve the purposes of encouraging the growth of cogeneration and small power production facilities, it will benefit ratepayers by providing them with the lowest cost option to meet resource needs.

The Commission should offer standard rates with conditions that are conducive to growth of cogeneration and small power production. Specifically, the Commission should require utilities to offer long-term levelized capacity payments and energy payments for a variety of terms, including terms long enough to provide a QF with sufficient certainty to obtain financing for and undertake capital expenditures.

Although the issue of standard rates has not been a primary focus of the TAC meetings, it should be addressed in the Staff report and considered by the Commission as an important part of the PURPA avoided cost framework. It is essential that both the avoided cost methodology and the mechanism by which QFs access avoided costs be fair, non-discriminatory, and promote development of cogeneration and small power production facilities.

²³ *Id.* at 12218.

²⁴ *Id.* at 12224.

²⁵ See *JD Wind 1, LLC*, 130 FERC ¶ 61,127 (2010) (“[FERC] always intended that nonfirm, intermittent QF resources are included in the phrase ‘each qualifying facility’ that has the option to choose to sell pursuant to a legally enforceable obligation.”).

²⁶ 45 Fed. Reg. 12223 (1980).

²⁷ See Order Setting Avoided Cost Input Parameters, Docket No. E-100, SUB 140, (North Carolina Utilities Commission, Dec. 31, 2014).

V. Conclusion

The Staff straw man proposal's preliminary estimate of technology-based avoided costs is a solid start towards developing an updated avoided cost methodology in Michigan. The proposed methodology should be expanded to account for the utility's full avoided cost, taking into account all of the factors FERC has directed states to evaluate. Evaluation of factors such as ELCC, transmission costs, hedging value, and avoided emissions is not only practicable, it is essential to developing technology-specific avoided cost rates that are fair and non-discriminatory. Staff should not lose sight of other important attributes of avoided cost, and should support standard rates that are available to QFs over 100 kW and that can be incorporated into legally enforceable obligations of sufficient duration to allow QFs to obtain appropriate financing. Michigan should join the other states and utilities undertaking these comprehensive analyses, the result of which will be a more robust avoided cost methodology that furthers the goals of PURPA.

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PV Valuation Methodology

Recommendations for Regulated Utilities in Michigan



February 23, 2016

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CPR's Solar Valuation Background

CPR holds a unique position in the solar valuation field, having developed the first value of solar tariff offered in North America. Austin Energy approved CPR's value-based pricing presented in a 2011 study, and offered it as a new form of compensation to its solar customers. CPR had performed an earlier valuation study for Austin Energy in 2006.

In 2014, CPR worked with utilities and stakeholders in Minnesota to develop the first detailed, public methodology to be used by utilities in setting rates. This methodology, guided by state legislative requirements, was approved by the Minnesota Public Utilities Commission for utilities seeking a value-based compensation tied to the costs and benefits of distributed solar generation. It is the only such Commission-approved methodology in North America.

In April 2015, CPR published a comprehensive market-based value of solar study that was commissioned by the Maine Public Utilities Commission. This study was also a stakeholder-driven process, and included a wide set of scenarios and assumptions for the purpose of informing public policy. It included three detailed studies for three utility regions.

CPR has performed a number of related studies, including net metering cost/benefit studies and solar fleet shape modeling for Duke Energy, We Energies, Portland General Electric, USD/San Diego Gas and Electric, Solar San Antonio, and NYSERDA/ConEdison. CPR has also worked with solar industry organizations, such as the Solar Electric Power Association (SEPA) and the Solar Energy Industries Association (SEIA) to evaluate other value-based compensation schemes, such as annual versus levelized VOS, long-term inflation-adjusted VOS, value of export energy, and others.

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PART 1 - INTRODUCTION

Introduction

Clean Power Research (CPR) was engaged by the Midwest Renewable Energy Association to develop a methodology for valuing distributed solar energy resources. Many studies have been performed by CPR and others over recent years to in which methodologies have been developed to perform these valuations.

Distributed solar differs from conventional generation in several respects. First, it is not dispatchable and therefore requires a means for evaluating its “effective” capacity to put it on a comparable economic footing with in-market resources.

Second, it is distributed, meaning that it avoids the losses associated with long-distance transmission, voltage step down at distribution substations, and the distribution lines. This requires that a loss savings factor be incorporated into the study.

Third, its production profile varies considerably, depending upon the orientation (azimuth and tilt angle) of the system and its location. As a practical approach, the concept of an aggregate “fleet” of resources is introduced to address this, and the valuation is designed to value output of the fleet.

Finally, solar provides a number of societal benefits, such as the ability to produce energy without harmful air emissions and protection against uncertainty in fuel price fluctuations. These benefits are “out of market” in the sense that the societal costs of conventional generation are not included in conventional ratemaking. It is left to the user of the methodology as to whether such benefits should be included in a valuation study.

Purpose

This report describes in general terms a methodology that may be used for such a valuation. For readability, the report is devoid of detailed equations and tables, and it does not include an actual valuation example based on this methodology. However, it does incorporate the lessons learned in a number of such valuation studies performed by CPR over the years.

In addition to the methodology, the report describes some options for implementation. These include the use of the methodology in evaluating existing net energy metering cross-subsidies,

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considerations for community shared solar, the adaptation of methods for energy exports and other DER technologies, and the use of results in value-based compensation schemes.

It is hoped that such a valuation exercise could be conducted using the methods described here.

Overview of Methodology

The methodology is described in three major parts. The first is a technical analysis where many of the key intermediate technical metrics are calculated. This include the definition of the study period, the rating conventions, the development of hourly fleet production profiles, the determination of “effective” capacity in relation to resource adequacy and the distribution system, and the treatment of loss savings.

The second part is the economic analysis of in-market benefits. This methodology includes avoided energy costs, avoided resource adequacy costs, avoided transmission capacity costs, and avoided distribution costs. It is important to note that this methodology incorporates some benefits that have been broken out as separate categories on other studies. For example, the energy benefit includes the economic impacts of both a change in load and a change in price. The resource adequacy benefit includes the contribution toward meeting both peak load and the planning margin.

Next, two out-of-market benefits are included. These are the benefits most commonly included in studies of this sort, and they include the avoided environmental cost and the fuel price guarantee. These benefits are more speculative and do not represent benefits for which a monetized transaction currently takes place in the energy marketplace.

PART 2 – TECHNICAL ANALYSIS

The Marginal PV Resource

The methodology incorporates in its framework the concept of a “Marginal PV Resource” for which the value of production is sought. Existing solar resources are not included in the analysis except to the extent that they shape the existing loads used in the analysis. It is understood that as the amount of solar in a system increases, the technical contribution towards capacity decreases. This is because the peak load shifts to non-daytime hours. Due to this effect, the initial solar resources (the “early adopters”) provide more technical benefits than systems

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installed in later years (the actual value depends on other factors such as fuel prices and these may increase or decrease).

With this in mind, it is necessary to state up front which of the solar resources are being evaluated: all resources to date? All resources anticipated over the next 20 years? This methodology is based on a marginal analysis of the next PV resource of unit size to come on line.

As described below, a PV Fleet Production Profile is developed that takes into account the diversity of locations and design attributes of the distributed solar fleet. The unit output of this fleet is, in effect, the Marginal PV Resource, even though such a resource does not exist in practice. The concept is helpful because it eliminates a set of complicating value scenarios (What is the value of a west-facing system? a tracking system? a system in the southern or northern part of the service territory?) The Marginal PV Resource therefore is the next installed increment of solar capacity that represents the geographical and design diversity of the distributed PV fleet.

Load Analysis Period and Economic Study Period

There are two separate periods of interest in performing the valuation: the Load Analysis Period and the Economic Study Period. The Load Analysis Period is used to evaluate technical parameters, such as the ability of the resource to deliver energy during peak times. Such analyses require the use of historical, measured data. For example, an evaluation of effective capacity may compare a year of hourly solar production against the same year of utility load. In this case, the Load Analysis Period would be defined as the year over which this technical analysis was based. The analysis could take place over several years (e.g., three years) in order to account for year-to-year load and weather variation.

The second period of interest is the Economic Study Period. This is the period over which the two economic alternatives are evaluated: the production of energy by the Marginal Resource and the delivery of energy using conventional generation. The costs and benefits of these alternatives occur in the future, so the Economic Study Period is selected over one or more future years.

The selection of Economic Study Period is often tied to the final metrics for presenting the benefits and costs, and the assumed useful service life of the resource (e.g., the 20 to 30 year life of solar PV) may be used. For example, if a 25 year service life is assumed, the study objective may be to estimate the levelized value over 25 years. Such an analysis would take into

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account anticipated capacity additions over this period, expected changes in wholesale energy costs, and load growth rates.

A valuation study may be designed to calculate a one-year, or first-year, value of generation. This is in contrast to a long-term levelized rate. Such an approach offers the advantage of accuracy because it is less dependent on long term forecasts (e.g., it would require a one-year fuel price forecast rather than a 25-year fuel price forecast). In this case, the investor in renewables takes the risk of future fluctuations in value. Rather than “locking in” a 25-year rate, the rate fluctuations year to year are unknown, and this may be an important factor in the investment decisions.

In the one-year analysis approach, long term benefits that fall outside of the analysis period, such as the avoidance of future generation capacity additions, may still be included. For example, a future year capacity addition could be included by amortizing the capacity cost of the addition over its expected life, calculating the present value of the annualized avoided costs that occur during the life of the Marginal Resource, and then amortizing this value over the life of the Marginal Resource. This results in the annual value attributed to the present resource in avoiding or deferring the need for future resources.

PV System Rating Convention

The methodology requires the establishment of a rating convention to be used for the Marginal Resource. There are several rating methods available, such as DC power under “Standard Test Conditions,” DC power under “PVUSA Test Conditions” (DC-PTC), and an AC rating that includes the effect of inverter efficiency.

The selection of rating convention is somewhat arbitrary, but must be used consistently. For example, if a DC rating is used, then the Marginal Resource would have a unit rating of 1 kW DC. When determining the annual energy produced, the same convention would be used: annual energy would be expressed as AC energy delivered to the grid per kW DC. Likewise, the effective generation capacity would be expressed as the effective generation capacity per kW DC.

Load Data and PV Fleet Production Profile

The capacity-related technical metrics that follow (see sections on Effective Load Carrying Capability and Peak Load Reduction below) are heavily dependent upon the assumed production profile of the Marginal PV Resource. If there is a good match between solar production and load, then the effective capacity is high. On the other hand, if the peak load

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occurs during times when solar production is poor, then the effective capacity will be low. This directly affects the economic capacity value.

Before calculating the match, it is necessary to obtain the load data and develop a solar production profile. Both the load and production profile are time series with start and end times corresponding to the Load Analysis Period described above. An hourly interval is most common for studies of this type, although other intervals could be used. MISO pricing is available in hourly intervals, and this will form the basis of the energy valuation. Therefore, hourly intervals are assumed here.

Two sets of load data are required: the MISO system load data and the utility distribution load data. The system load data will be used to calculate effective generation capacity, so the load data should correspond to the MISO zone associated with the utility. The distribution load data will be used to calculate the effective distribution capacity.

In addition, a production profile representing the output of the Marginal Resource is required over the Load Analysis Period. This can be either simulated or measured from sample PV resources, but must accomplish the following:

- The data must accurately reflect the diversity of geographical locations across the utility and the diversity of design orientations (range of azimuth angles and tilt angles, etc.). Typically, this requires the aggregation of several hundred systems comprising a representative “fleet” of solar resources.
- The data must not represent “typical year” conditions, but rather must be taken from the same hours and years as the load data. It must be therefore “time synchronized” with load.
- The gross energy output of the resource is required, not the net export energy which includes on-site consumption.

The fleet comprises a large set of real or anticipated PV systems having varying orientations (different tilt angles and azimuth angles) at a large number of locations. The intention is to calculate costs and benefits for the PV fleet as a whole, rather than for a specific system with specific attributes.

Effective Load Carrying Capability (ELCC)

Distributed solar is not dispatchable in the market, but it does have an indirect effect on the amount of power that is dispatched. If distributed solar produces energy during peak load

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hours, then the required amount of dispatchable capacity is lowered. Therefore, it is important to quantify how effective distributed solar is in reducing capacity requirements.

Effective Load Carrying Capability (ELCC) is the metric used for this purpose. It is typically expressed as a percentage of rated capacity. For example, if solar is credited with an ELCC of 50%, then a 100 kW solar resource is considered to provide the same effective capacity as a 50 kW dispatchable resource.

MISO is working to develop a process¹ for solar accreditation and several alternatives used at other ISOs are under consideration. When such a process becomes defined, it could be used to calculate ELCC using the PV Fleet Production Profile.

Before the process is developed, it will be necessary to select an interim method, and one such method is described here. This method has been used in other studies by CPR² and can be used as an easily implemented method until the MISO process is available.

Under the MISO tariff, Load Serving Entities (LSEs) are required to meet both a local clearing requirement (LCR) in their local resource zone (LRZ) as well as MISO-level planning reserve margin requirement (PRMR). Both of these requirements ensure that reliability meets a 1 day in 10 year loss of load standard. Each of the two requirements is considered separately.

First, the contribution of distributed solar in meeting the LCR requirement is dependent upon the load match of solar production with the zonal load. This could be evaluated as the average of the PV Fleet Production Profile during the peak 100 hours per year in the LRZ. The contribution of these distributed resources not only reduce the required resources to meet the peak zonal load but also reserve requirements. For example, if the average production during the peak 100 hours in the LRZ was 0.5 kWh per hour per kW of rated solar capacity and if the local resource requirement per unit of peak demand was 1.1, then the effective contribution of solar would be $0.5 \times 1.1 = 55\%$ of rated capacity.

Second, the contribution of distributed solar in meeting the PRMR requirement is dependent upon the load match with the MISO system load. In this case, the contribution could be calculated by averaging the PV Fleet Production Profile during the peak 100 hours per year in the MISO footprint and applying the planning reserve margin. For example, if the load match

¹ See "MISO Solar Capacity Credit" at:

<https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/SAWG/2015/20150806/20150806%20SAWG%20Item%2007%20Solar%20Capacity%20Credit.pdf>

² E.g., a 2014 valuation study for the Maine PUC.

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was 40% and the margin was 7%, then the effective contribution of solar would be $0.4 \times 1.07 = 43\%$ of rated capacity.

Finally, the LSEs may use the same resource to serve both the LCR requirement and the PRMR requirement. The effective capacity, or ELCC, would be selected as the lower of the two results. Continuing the example, if the effective solar capacity was 55% for LCR but only 43% for PRMR purposes, then the overall ELCC would be 43%.

Peak Load Reduction (PLR)

The ELCC is a measure of effective capacity for resource adequacy. It is an essential input to evaluating the benefit of avoided generation capacity costs. However, it is not necessarily a good metric for evaluating avoided transmission and distribution (T&D) capacity benefits for two reasons: (1) it is based on the loads of the MISO zone, rather than the utility's distribution loads (peaks make occur at different times); and (2) it averages output over many hours, whereas distribution planning requires that the resource be there for a small number of peak hours.

Therefore, a different measure of effective capacity can be used in evaluating the distribution benefits. The Peak Load Reduction (PLR) is defined as the maximum distribution load over the Load Analysis Period (without the Marginal PV Resource) minus the maximum distribution load over the Load Analysis Period (with the Marginal PV Resource).

The distribution load is the power entering the distribution system from the transmission system (i.e., generation load minus transmission losses). In calculating the PLR, it is not sufficient to limit modeling to the peak hour. All hours over the Load Analysis Period must be included in the calculation. This is because the reduced peak load may not occur in the same hour as the original peak load.

Loss Savings Analysis

Distributed solar resources not only displace energy delivered to the load. They also avoid losses in the transmission and distribution lines. To account for this, Loss Savings Factors are calculated and incorporated into the analysis.

Loss Savings Factors depend on the benefit and cost category under evaluation. For example, one Loss Savings Factor could be determined for the avoided energy costs by determining the losses that would be incurred in the absence of PV the solar hours of a given year, and comparing this to the losses that would be incurred during those same hours if the Marginal

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Resource were present. The difference could be expressed in a Loss Savings Factor associated with the avoided energy costs.

The Loss Savings Factor associated with avoided distribution capacity costs, however, would be different from the one associated with energy. This is due to two factors. First, as described in the PLR metric, only the peak distribution hours are of interest in calculating the PLR. Avoided losses during non-peak hours (e.g., mid-morning hours) are not relevant to the determination of avoided distribution capacity costs. Second, only the avoided losses in the distribution system are relevant to the distribution benefit calculation. Avoided losses in the transmission system should not be included.

Three Loss Savings Factors should be developed as shown in Table 1.

Table 1. Loss Savings Factors

| Loss Savings Factor | Loss Savings Considered |
|------------------------------|--|
| Avoided Annual Energy | Avoided transmission and distribution losses for every hour of the Load Analysis Period. |
| ELCC | Avoided transmission and distribution losses during the 100 peak hours in each year of the Load Analysis Period. |
| PLR | Avoided distribution losses (not transmission) at the distribution peak. |

When calculating avoided marginal losses, the analysis should satisfy the following requirements:

1. Avoided losses should be calculated on an hourly (not an annual) basis over the Load Analysis Period. This is because solar tends to be correlated with load and losses during high load periods exceed average losses.
2. Avoided losses should be calculated on a marginal basis. The marginal avoided losses are the difference in hourly losses between the case without the Marginal PV Resource, and the case with the Marginal PV Resource. Avoided average hourly losses are not calculated. For example, if the Marginal PV Resource were to produce 1 kW of power for an hour in which total customer load is 1000 kW, then the avoided losses would be the calculated losses at 1000 kW of customer load minus the calculated losses at 999 kW of load.
3. Calculations of avoided losses should not include no-load losses (e.g., corona, leakage current). Only load-related losses should be included.

- Calculations of avoided losses in any hour should take into account the non-linear relationship between losses and load (load-related losses are proportional to the square of the load, assuming constant voltage).

PART 3 – ECONOMIC ANALYSIS

Avoided Energy Costs

Distributed solar reduces the wholesale cost of energy in two respects. First, it reduces the quantity of energy procured in the MISO market for delivery to customers. Solar production displaces energy that would have been procured at a given price in a given hour. Second, it lowers demand for energy, resulting in lower clearing prices for all transactions, an effect sometimes referred to as the “market price response.”

The goal of the valuation analysis is illustrated in Figure 3, which shows the relationship between price and load in a given hour. As load increases (or decreases), the price similarly increases (or decreases). This relationship reflects the supply and demand of resources participating in the market.

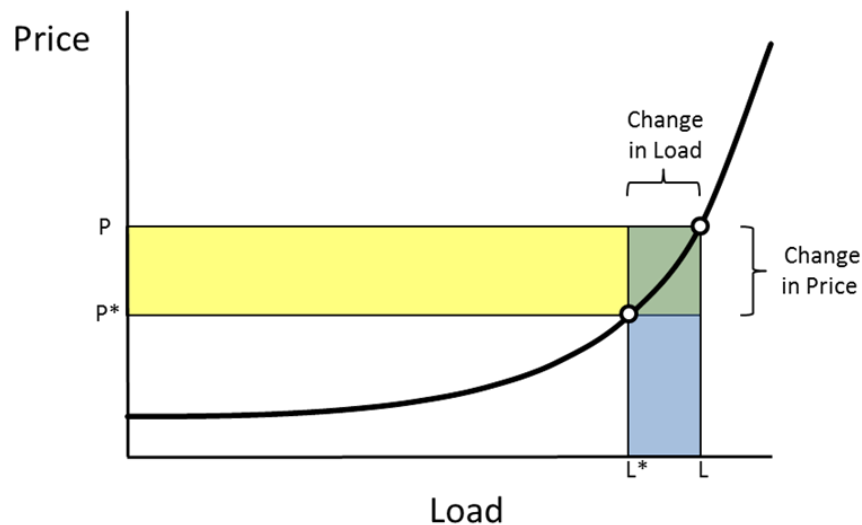


Figure 1. Avoided Energy Cost (Illustrative)

In this illustration L represents the measured load in any given hour, and P represents the corresponding price (the MISO day-ahead clearing price). The Marginal PV Resource reduces load from L to L^* and price from P to P^* . This reduces the total wholesale cost of energy from LP to L^*P^* and the savings are represented by the shaded regions.

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The calculation of savings may be performed in two steps. The first step is to multiply the observed market price P by the change in load (the blue area). The change in load is the PV fleet production for the hour. This is done for each hour of a sample year and summed.

The second step is to multiply the resulting load L^* by the reduction in price. This requires an estimate of the change in price which may be obtained from a model such as the one illustrated in Figure 2. This shows hourly load-price points for a given month at a sample ISO. From these points a model F may be developed as a least squares curve fit. Then, the analysis can assume that the change in price from P to P^* is proportional to the change in F . The calculation is done for each hour of the year and summed.

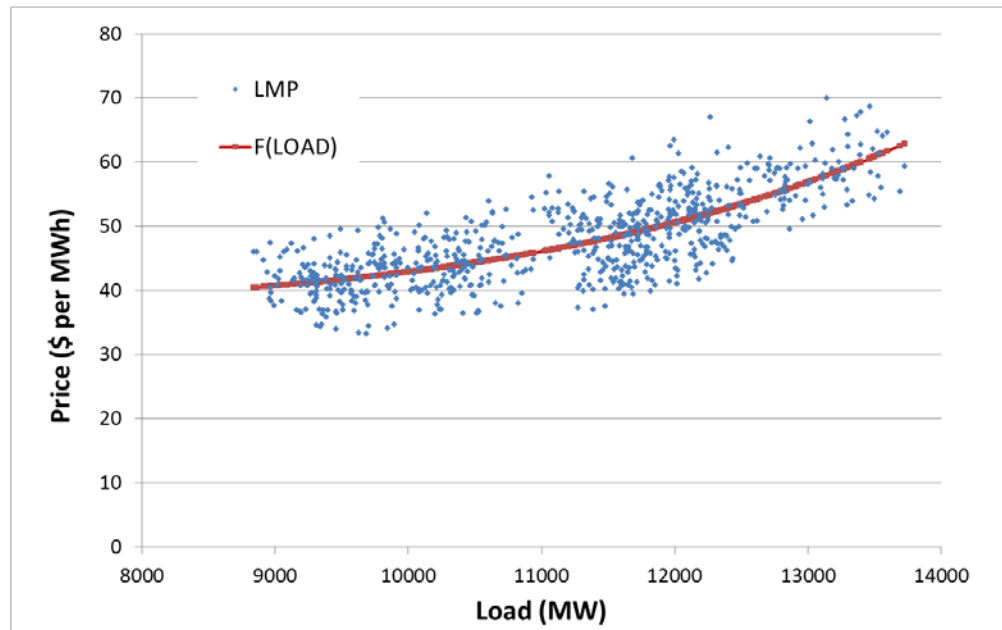


Figure 2. Load Versus Price Model F

Avoided Cost of Resource Adequacy

Part 2 described a method for calculating ELCC, a measure of the effectiveness of distributed solar resources in meeting resource adequacy requirements. The avoided cost, then, is calculated by multiplying the ELCC by the cost of new entry (CONE) for the LRZ. CONE indicates the annualized capital cost of constructing a new plant.

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CONE is calculated by MISO³ by annualizing the net present value (NPV) of the capital cost, long term O&M costs, insurance and property taxes. There are other measures of capital cost,⁴ such as the MISO planning auction, but these do not necessarily correspond to the long-term (e.g., 25 year) service provided by solar.

Voltage Regulation

Distribution utilities have the responsibility to deliver electricity to customers within specified voltage windows as required by State rules. When PV or other distributed generation resources are introduced onto the grid, this can affect line voltages depending upon generator rating, available solar resource, load, line conditions, and other factors. Furthermore, at the distribution level (in contrast to transmission) PV systems are more geographically concentrated. Depending upon concentration and weather variability, PV could cause fluctuations in voltage that would require additional regulation.

In some cases, these effects will require that utilities make modifications to the distribution system (e.g., adding voltage regulation or transformer capacity) to address the technical concerns. For purposes of this methodology, it is assumed that such costs are born by the solar generator. Consequently, no cost is assumed related to interconnection costs.

Advanced Inverters

Advanced inverter technology is available to provide additional services which may be beneficial to the operation of the distribution system. These inverters can curtail production on demand, source or sink reactive power, and provide voltage and frequency ride through. These functions have already been proven in electric power systems in Europe and may be introduced in the U.S. in the near term once regulatory standards and markets evolve to incorporate them.

Based on these considerations, it is reasonable to expect that at some point in the future, distributed PV may offer additional benefits, and voltage regulation benefits may be included in a future methodology.

³ See “Cost of New Entry: PY 2016/17,” at:

<https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/SAWG/2015/20151029/20151029%20SAWG%20Item%2004%20CONE%20PY%202016-2017.pdf>

⁴ See “Michigan Public Service Commission Solar Working Group – Staff Report” at

<https://efile.mpsc.state.mi.us/efile/docs/17752/0045.pdf>

Avoided Transmission Capacity Cost

Distributed PV has the potential to avoid or defer transmission investments, provided that they are made for the purpose of providing capacity, and provided that the solar production is coincident with the peak. The challenge is finding the cost of future transmission that is avoidable or deferrable as a result of distributed generation. As a proxy for this price, transmission tariffs used to recover historical costs may be used.

In the MISO footprint, network transmission service to load is provided under the Open Access Transmission Tariff (OATT) as a per-MW demand charge that is a function of monthly system peaks. Using the PV Fleet Production Profile and the hourly loads of the zone, the average monthly reduction in network load may be calculated for the Marginal PV Resource. For example, the reduction in January network load for a given year would be calculated by first subtracting the PV Fleet Production from load every hour of the month. Then, the peak load for the month without PV is compared to the peak load with PV, and the difference, if any, is considered the reduction in network load for that month. A similar analysis would be performed for the remaining 11 months of the year. For each month, the reduction in peak demand would be multiplied by the zonal network price in the OATT Schedule 9.

Avoided Distribution Capacity Cost

In calculating the avoided distribution cost, the PLR is used as the load match factor. This is multiplied by the NPV of distribution capacity over the Economic Study Period. For example, if the Economic Study Period is 25 years, then the cost of new distribution capacity within the geographical area of interest should be estimated for each year in this period.

Detailed cost estimates are generally available only for areas facing near term capacity upgrades, making it difficult to perform this analysis. Therefore future costs outside the planning horizon may be made based on a projection of costs and peak loads over a representative historical period, such as the last 10 years, and must correspond to anticipated growth rates. Costs for reliability-related purposes should not be included because they are not avoidable by distributed solar.

PART 4 – OUT OF MARKET BENEFITS

Avoided Environmental Cost

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With distributed PV, environmental emissions including carbon dioxide (CO₂), sulfur dioxide (SO₂), and nitrous oxides (NO_x) may be avoided. In general, it is relatively straightforward to calculate the technical impact—for example, through the use of the Environmental Protection Agency’s AVERT tool—but the estimates of avoided social costs are more difficult to quantify.

Estimates of social costs must be taken from external studies. The social cost of carbon, for example, may be based on results from the Interagency Working Group on Social Cost of Carbon.⁵

It should be noted that costs to comply with environmental standards (scrubbers, etc.) are embedded in the energy costs already described. The technical calculations of emissions should therefore already take into account the compliance measures used to reduce emissions. The social costs are therefore associated with the emissions after compliance has been met (the “net” emissions) and the costs are therefore in addition to compliance.

Fuel Price Guarantee

This value accounts for the fuel price volatility of natural gas generation that is not present for solar generation. To put these two generation alternatives on the same footing, the cost that would be incurred to remove the fuel price uncertainty may be included. This can be accomplished by estimating the natural gas displaced by PV over the Economic Study Period and determining the cost of natural gas futures required to eliminate the uncertainty.

Note that price volatility is also mitigated by other sources (wind, nuclear, and hydro). Therefore, the methodology is designed to quantify the hedge associated only with the gas that is displaced by PV.

PART 5 – IMPLEMENTATION OPTIONS

Evaluation of Existing Net Metering Programs

A valuation using the above methods would result in the avoided costs per kWh of distributed solar generation. This valuation could then be used to evaluate the question of whether solar

⁵ The annual Social Cost of Carbon values are listed in table A1 of the Social Cost of Carbon Technical Support Document, found at: <http://www.whitehouse.gov/sites/default/files/omb/assets/inforeg/technical-update-social-cost-of-carbon-for-regulator-impact-analysis.pdf>.

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customers under net energy metering (NEM) rates are subsidizing non-solar customers or whether non-solar customers are subsidizing NEM customers.

NEM customers are only billed (or credited) for the difference between their consumption charges and their generation credits. It has been argued that fixed costs recovered through volumetric rates may not be recovered equitably because NEM customers are able to reduce their monthly net consumption. On the other hand, NEM customers may provide additional benefits, resulting in savings to other customers. For example, a NEM customer may be delivering energy and capacity to the grid at times when it is most valuable. Using the methods described here can help to determine whether cost shifting is taking place and the direction of cost shifting (whether solar customers are subsidizing or being subsidized by non-solar customers, as the case may be).

Considerations for Community Shared Solar

Some customers do not have good options to install solar on their rooftops. They may not own their building (especially in the case of commercial customers), the building may be heavily shaded, or it may not lend itself to solar due to architectural considerations. For these, customers, community shared solar may be an option. Systems built for this purpose may be sited in more desirable locations with good solar access and may be built with higher ratings at lower cost per kW.

However, the methodologies described above may have to be adjusted. There are two factors that must be considered. First, the production profile of these systems will be different than that of the overall fleet as described in Part 2. These systems will be built at optimal orientation (e.g., south facing at an optimal tilt angle) in order to maximize the energy production. Therefore, the production profile associated with such an optimal design should be used rather than the fleet profile.

It should also be noted that the shared solar resource may be electrically distant from the member-customer. In a sense, the energy would have to travel from the shared resource to the customer, and this would include additional losses not accounted for in the methodology. However, the energy in practice would not be delivered to the specific customer but simply accounted for and credited through metering. The energy produced by the resource would still result in avoided losses, except that the losses would be avoided in delivering energy to non-members rather than to the members themselves. The methodology would provide a reasonable accounting of this benefit. Such would not be the case if the shared resource were outside of the service territory of the utility.

Value of Exported Solar Energy

In some studies, the value of export energy is sought rather than the value of gross solar production. This may be the case, for example, in developing a tariff in which self-consumption is used to reduce a customer's electricity bill. Such a rate would effectively provide the customer-generator with two benefit streams: the benefit of lower utility bills due to self-consumption and the benefit of a bill credits associated with the value of export energy. From the utility perspective, such a mechanism also results in two impacts: lost revenue from the self-consumption and lost revenue associated with those bill credits that are exercised.

Regardless of perspective—customer or utility—the economic analysis requires as study inputs the hourly load profile and the relative size of the solar system and the load. This data is necessary to calculate the hourly export profile, and this is a different shape and magnitude than the gross production. If solar generation is self-consumed during the daytime, the mid-day export may be low or non-existent, in contrast to the PV Fleet Production Profile described in this methodology. This means that the capacity value will be different since it is dependent upon the match of between solar and load.

Customers have a choice in sizing their systems. Depending upon size, more or less energy will be delivered to the grid as export energy. Therefore, a study of the export energy value would have to include scenarios that handle these size variations. For example, scenarios could be developed in which solar provides 100%, 75%, 50% and 25% of the annual energy.

Finally, the details of the customer load profile are important. One residential customer, for example, may have a different load profile than another. The export energy profile will therefore be different even if other factors such as system design are the same.

Including multiple scenarios of relative size and profile shape may prove impractical due to the additional technical effort to address each scenario as well as the complexity in determining which result to apply to a given customer. Therefore, the study approach might consider just one or a small number of representative scenarios as an approximation.

Qualifying Facilities Rates

Many of the methods described here could be used to help identify a solar-specific avoided cost rate for qualifying facilities under PURPA. The resulting rate would incorporate many of the solar-specific attributes, such as the hourly production profile, intermittency, and loss savings.

Applicability to Other DER Technologies

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Aspects of this methodology may be used for other DER technologies, such as storage and efficiency. However, the PV Fleet Production Profile would have to be replaced with a profile suitable to the technology. For example, energy storage may have a profile that includes off-peak charging and on-peak discharging. If the profile were known, or if they were assumed in a scenario analysis, then the rest of the methodology could be used to calculate the value of these resources.

Real Time Pricing with AMI

In some cases, such as storage (a dispatchable resource), the customer has control of its operation, so the generation profiles may not be known. Value-based rates calculated using an assumed production profile might therefore not be valid for these cases.

If the goal of the valuation is to develop a mechanism for compensation, the methodology may be adapted for use in a technology-neutral value-based rate using real-time pricing. In this case, the DER profile may be determined at the conclusion of the billing month and applied against actual energy prices (e.g., LMPs). In the case of storage, the charging or discharging periods would correspond to energy charges and credits. Capacity value could be fixed for non-dispatchable resources but could require adherence to resource qualification standards similar to the MISO standards and utility control (or penalties for not dispatching during critical peaks).

Value of Solar Tariffs

Value of solar tariffs (or VOST) were introduced by Austin Energy in 2012 and by Hawaiian Electric in 2015. These tariffs intend to provide compensation for solar based on value. Austin Energy, for example, uses a methodology similar to the one described here and incorporating market-based prices in ERCOT. The Hawaiian Electric “grid supply” option provides for self-consumption and a rate for export energy based on marginal energy costs.

Baldwin, Julie (LARA)

From: Robert Evans <robertevans@nanr.net>
Sent: Thursday, March 03, 2016 8:59 AM
To: Baldwin, Julie (LARA)
Subject: PURPA TAC Comments

Julie: I have several comments on Staff's Strawman Avoided Cost Proposal. The following items should be considered:

1. Interim Additions. Interim Additions are those capital costs that are incurred over the life cycle of a generating station that are necessary and inescapable to maintain plant operations, whether dictated by regulation or equipment service life. In the case of a coal plant, those capital costs over the life cycle of the generating station might equal or exceed the initial cost of the plant's construction and commissioning.

In the case of a combined cycle facility (with its industrial grade gas turbine (jet engine)) should that type facility be used as the basis for determining a capacity cost, over a twenty- five year period, a substantial portion of the plant will be upgraded or replaced four or five time, including the turbine's hot section, gear box for speed reduction to the generator, etc.

Although the operational cost of a qualifying facility is not relevant to the avoided cost determination under PURPA, landfill gas generating stations also incur the same equipment replacement capital costs almost every five years.

Interim Additions are not operational, nor maintenance. They are for equipment upgrade or replacement, are capital cost in nature, and should be included in determining a capacity charge.

2. Interconnection Cost. The cost to interconnect any generating station to the utility grid, including substation, power line extension, relaying, switching, and coordination and interface with the transmissions system away from the plant, are capital in nature and should be significant elements in determining a capacity cost.

One SW Michigan utility charged a Qualifying Facility \$2,500,000 to interface its 4.8 MW landfill gas generating station to its 69 kV sub-transmission system. And that was after the QF built its own 69 kV substation and approximately one mile of 69 kV line to reach the utility.

Without an interconnection and the associated costs, a generating station cannot operate and therefore, has no value.

Interconnection is a significant portion of every power plant's cost to build.

3. RECs. In determining the capital cost and the energy cost of the avoided unit, no renewable value is considered.

Under PURPA, the REC should be a value added to the utility that should be considered in the same way that a QF's location on the distribution system (saving transformer loss and transmission loss) should be considered as a value added.

Thank you.

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February 24, 2016

**RESPONSES OF THE INDEPENDENT POWER PRODUCERS COALITION OF MICHIGAN (IPPC)
GROUP TO THE STAFF'S AVOIDED COST STRAWMAN PROPOSAL**

The IPPC Group appreciates the effort and thought that went into the Staff Strawman Proposal. While this response includes several suggestions for changes to the Staff model, we nevertheless believe that the Staff proposal is moving in the right direction and is responsive to many of the concerns that IPPC has expressed.

I. THE STAFF'S TRANSFER PRICE SCHEDULE MEETS THE FEDERAL LAW'S REQUIREMENT THAT AVOIDED COSTS BE JUST AND REASONABLE, IN THE PUBLIC INTEREST, AND NOT DISCRIMINATE AGAINST THE STATE'S QUALIFIED FACILITIES.

The IPPC strongly believes that there is no better representation of what a true avoided cost template should look like than that which has been used over the past 9 years by the Commission in its Transfer Price Schedule. As this Commission recently stated in its 2016 Renewable Energy Report, "(t)ransfer price schedules are representative of what a Michigan electric provider would pay had it obtained the energy and capacity (the non-renewable market price component) through a new long term power purchase agreement for traditional fossil fuel electric generation. To best determine the value of the non-renewable component of Act 295 compliant generation, Commission Staff determined, for purposes of developing a uniform

Transfer Price Schedule, that the levelized cost of a new natural gas combined cycle (NGCC) plant would likely be analogous to the market price mentioned above.”¹ Use of the Transfer Price Schedule as the proxy for avoided cost, since it is itself based on a NGCC unit – which as we discuss below, is the appropriate proxy for the avoided cost, and would satisfy the obligation under the Public Utility Regulatory Policy Act of 1979 (PURPA) to be just and reasonable and in the public interest. In fact, it has already been found to satisfy those criteria in multiple Commission proceedings. Furthermore, since the Transfer Price Schedule offers a projected cost over a multi-year horizon, it also offers the opportunity to establish an avoided cost schedule that could be the basis of a multi-year power purchase agreement.

II. IPPC'S COMMENTS ON THE STAFF'S STRAWMAN PROPOSED MODEL

IPPC believes that the previous work of the Commission, reflected in dockets U-6798 and U-8871, should be respected; and while it needs to be updated, the essential model adopted there is still appropriate and relevant for establishing avoided costs for Michigan's PURPA Qualifying Facilities (QF). We believe that the Transfer Price Schedule, using as it does a proxy generation unit, is consistent with the approach taken in the previous dockets. We are pleased that the Staff proposal follows the structures embraced by the previous model and does not attempt to establish an entirely new vision of how avoided costs should be set. That said, the IPPC has some suggestions for revision to the Staff proposal as follows.

¹ Report on the Implementation of the P.A. 295 Renewable Energy Standard and the Cost-Effectiveness of the Energy Standards, Michigan Public Service Commission, February 12, 2016 ("2016 Renewable Energy Report"), at pp. 32-33.

A. Levelized Costs, and not LMP Day Ahead Prices, are the Appropriate Cost Measure

In its proposed calculation of the energy component, Staff provides three options. While the concept of offering options is not itself objectionable, IPPC is concerned that the options provided are so far away from each other in methodology and result that they are likely to be a continuing source of controversy that could lead to further proceedings before the Commission to settle disputes over them.

First of all, IPPC believes that the MISO Locational Marginal Price (LMP) at the appropriate node is not a reasonable proxy for avoided energy costs of the utility. For one thing, QF contracts in Michigan have traditionally been long-term contracts, and the LMP does not reflect any long-term forecast of energy costs. Staff's second option, the levelization of projected LMP over the contract term, at least has the benefit of attempting to account for the value over time of the energy being provided. That being said, the LMP, even levelized over time, does not capture the true avoided costs, as required by PURPA.

IPPC believes that the most appropriate and reasonable manner to address the energy component is to use the third option the Staff has provided – the levelized variable costs of a combined cycle natural gas plant over the contract term, consistent with how the Commission utilizes this proxy for its Transfer Price Schedule. As IPPC believes that such a plant should be the basis for the capacity calculation (see below), this would have the virtue of being a consistent application of the proxy model across all costs, which is the most reasonable way to apply the model.

Using a levelized cost rather than spot market costs better reflects the utility's long-range planning horizon. It would not be prudent operation for any utility to base its determinations about making long-term purchases of energy, or about building more generation, on spot market

prices. Instead, any prudent utility looks at long-term trends in fuel costs, load growth, and other factors. None of these factors is reflected in the spot market price, and so that price does not satisfy the federal requirement that the avoided cost must reflect the costs that the utility is avoiding by not having to generate itself or purchase from another source because of the (long-term) contracts that it has entered into with QFs. See 18 CFR 292.101(b)(6).

Use of levelized costs and long-term contracts also provides a hedge for the utility against fuel and generation cost increases over the planning horizon. Again, this is not a benefit that can be reflected in the spot market cost, but which the avoided cost rate should reflect.

B. PURPA Imposes Legal Obligations on the Regulated Utility

PURPA imposes a number of legal obligations on regulated utilities. In the PURPA – TAC meetings we have heard representatives of Michigan’s two largest regulated utilities question this and whether if others should be bearing those obligations, such as Alternative Electric Suppliers (AESs) and transmission owners. As Staff knows, PURPA imposes a mandatory purchase obligation on each "electric utility," as that term is defined by federal rules and law, which is broadly defined as "any person, State agency, or Federal agency, which sells electric energy."² AESs, of course, are not defined as utilities in this state. And federal law remains clear that it is the electric utilities that must offer to purchase electric energy from any QF that can deliver power to the utility.³ At the very least, we are pleased that the Staff has not let itself be distracted by these red herrings. If the utilities have complaints to make about the functioning of federal law, this workgroup is not the place to try to address them.

² PURPA §3(4), 16 U.S.C. §2602(4); in essence, the requirement rests on the local distribution company.

³ PURPA §210(a).

That said, PURPA requires that purchases by electric utilities from QFs subject to the “must purchase” obligation be 1) “just and reasonable to the electric consumers of the electric utility and in the public interest,” 2) non-discriminatory “against qualifying generators or qualifying small power producers,” and 3) that federal rules shall not require “a rate which exceeds the incremental cost to the electric utility of alternative electric energy” or its “avoided cost.” See 16 U.S.C. § 824a-3(b) and 18 CFR 292.101 *et seq.*

We have heard representatives from the utilities arguing in the workgroup meetings that it would be somehow unfair or unreasonable if satisfying their federal PURPA obligations causes them to spend more than they would if they just obtained the cheapest energy or capacity they could at the moment. However, that is not what the federal law says. Instead, it requires that the resulting costs to the utility to meet its must purchase obligations be “just and reasonable to the electric consumers” and “in the public interest,” not that it be the cheapest source available. Conversely, it would also not meet the federal law's standards if the QFs proposed a cost that was the highest cost available. The Commission must find that balance that meets a just and reasonable cost to the utility’s customers and is in the public interest – and is non-discriminatory to the QF. Simply finding “the lowest incremental cost” possible would violate PURPA's requirement of a just and reasonable rate to the QF.

As the IPPC group presentations illustrated, there are a number of public interests involved in continuing the operations of these QFs besides the obtaining of cost-effective capacity and energy. It is consistent with federal law for the avoided cost determination to reflect such public interests. Furthermore, as Ken Rose noted in his presentation, avoided cost means “the incremental cost of the utility to generate or purchase itself without the QF or QFs – over the relevant utility planning horizon.” And he added, “that is, long term that takes into

account capital expenditures.” See Ken Rose presentation to PURPA – TAC, 02-03-2016, slide 8.

C. Staff’s Capacity Payment Component Should be Consistent with the Energy Component.

Staff’s proposal for capacity payment used a combustion turbine natural gas plant (simple cycle, or CT) as the proxy. This is problematic as it is widely acknowledged that the next build – if new generation is required – is most likely to be a combined cycle gas plant (NGCC). The only basis provided for this choice in Staff’s proposal is that it “[r]epresents the most cost-effective new entry into the energy market.” The problem with that rationale is that it is not a reasonable basis for the proxy choice under federal law or the proxy method, which require not the lowest cost choice, but the one that the utility itself would build if it were not for the presence of the QFs. See, *PURPA Title II Compliance Manual*, “Proxy resource method,” p. 35. Consumers Energy recently demonstrated what its choice for its next planned addition would be when it proposed the combined cycle natural gas plant at Thetford (see Case No. U-17429). There has been nothing presented to the workgroup that would make a compelling case for anything different as the proxy unit.

D. Intermittent and Baseload Generation Technologies Need Different Proxies to Reflect Differences in Benefits to the System and Costs Avoided.

IPPC understands from the workgroup discussion on February 10, 2016, that Staff provided the “NGCC Energy Adjustment” in an effort to counter the concerns expressed above regarding using CT as the capacity measure, and that by shifting the costs from capacity to energy via that Adjustment there was an intent to account for differences between intermittent

and baseload technologies. IPPC nevertheless believes that this can be accomplished more cleanly, simply, and accurately by establishing different proxies for intermittent and baseload technologies. Thus, solar and wind, to take two examples, as intermittent technologies might have a CT proxy for capacity and energy, while the IPPC member units, which are all baseload units, would have a NGCC proxy for capacity and energy.

Such a distinction is anticipated in the Federal rules, which state that “[t]he standard rates for purchases under this paragraph . . . [m]ay differentiate among qualifying facilities using various technologies on the basis of the supply characteristics of the different technologies.” 18 CFR 292.304(c)(3). This is a more reasonable way to address the fundamental difference between baseload and intermittent technologies than the method proposed in the Staff’s February 10, 2016 proposal.

E. The Utility’s Long-Range Planning Includes the Existing Capacity from QFs Under Contract

While Staff’s proposal covered payment for capacity, it did not address the issue of when a utility is obligated to purchase capacity from a QF. As the utilities’ obligation to purchase energy and capacity from QFs has existed for over 25 years, those facilities that have long been part of a utility’s long-range planning for capacity and energy should enjoy a presumption, when their contracts are due for replacement or renewal, that the utility will continue to be obligated to purchase their capacity going forward. This presumption simply recognizes that the utility has a continuing federal legal obligation to purchase capacity and energy from the QF so long as the QF continues to offer it, even upon termination of the existing contract. A utility should not be able to claim that it no longer needs the QF’s capacity (perhaps in the hope that it will be able to

build and rate base a new generation source itself) unless there is some extraordinary reason, such that the continued purchase of the QF's capacity is no longer in the public interest.

F. PURPA QFs Should Retain the Renewable Credits

Because the proxy that Staff is proposing is based on a fossil fuel fired generation source, and so does not account for any of the renewable benefits of the QFs, those renewable benefits should belong to the QF unless they are otherwise contracted for between the QF and the utility. To do otherwise is to arbitrarily take value provided by the QF and give the utility the benefit of that value without concomitant payment to the QF. IPPC recognizes that the value of RECs and other means of measuring the renewable benefits provided by QF generation are difficult to project and subject to dispute, and so we propose that rather than trying to assign these a value they be left with the QF, unless the utility wishes to acquire them, in which case their value will be determined in arms-length negotiation between the parties.

III. SOURCES OF COST DATA

The IPPC has identified several possible sources of cost data that the Staff could use, all of which have been used in one way or another in MPSC cases recently, or are otherwise government-authorized numbers and so are less likely to be subject to accusations of bias in their derivation. If not used directly, these data at a minimum should be used to verify the reasonableness of the avoided cost derived through the MPSC prescribed methodology.

A. Transfer Price Schedule

As discussed above, this schedule, which provides yearly and forecasted costs, would make an excellent proxy to establish the avoided costs of the utility. Attached is the schedule recently supported by Consumers Energy in Case No. U-17792, as Exhibit A-17.

B. EIA Data

In its Annual Energy Outlook 2015, EIA provided levelized costs and avoided costs for new generation both nationally and on a regional level. These numbers are updated annually.

http://www.eia.gov/forecasts/aeo/electricity_generation.cfm

C. Thetford Filing Data

Consumers provided what it at the time argued were its just and reasonable costs for its next source of generation in the Certificate of Necessity docket, U-17429. Consumers provided levelized cost of generation in Exhibit A-35: \$100.89 – 125.05 / MWH.

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April 1, 2016

Mr. Paul Proudfoot
Director – Electric Reliability Division
Michigan Public Service Commission
7109 W. Saginaw Highway
Lansing, MI 48917

**Re: MPSC Case No. U-17973
PURPA Technical Advisory Committee
Report on the Continued Appropriateness of the
Commission’s Implementation of PURPA¹**

Dear Mr. Proudfoot:

On March 15, 2016, the Michigan Public Service Commission (“MPSC”) Staff issued its draft “Report on the Continued Appropriateness of the Commission’s Implementation of PURPA” (“Draft Report”) for review by the participants in the Commission’s PURPA Technical Advisory Committee (“PURPA TAC”). This letter constitutes Consumers Energy Company’s (“Consumers Energy” or the “Company”) comments on the Draft Report. Consumers Energy thanks the MPSC Staff for the hard work it put into the PURPA TAC meetings and the consideration given to all the comments provided by PURPA TAC participants.

The Draft Report identified four goals to be addressed by the PURPA TAC: 1) determine potential on-going routine administrative processes for approving avoided cost to be paid to PURPA Qualified Facilities (“QF”); 2) determine potential methodologies for establishing avoided cost to be paid to PURPA QFs; 3) develop a recommendation of the process and methodology to be utilized for establishing and approving avoided cost to be paid to PURPA QFs; and 4) determine if support for the recommendation is a consensus or if alternate recommendations are supported.

Goal 1 – Determine Potential On-going Routine Administrative Processes for Approving Avoided Cost to be Paid to PURPA QFs.

MPSC Staff recommends an initial process to establish a methodology to replace the historical coal based methodology of determining a utility’s avoided costs employed by the MPSC since PURPA was enacted in 1978, followed by biennial updates to “refresh” the determinants for determining a utility’s avoided costs. Thereafter, contracts filed by the utility and shown not to be in excess of the utility’s avoided costs would be approved by the MPSC.

¹ Public Utility Regulatory Policies Act of 1978.

In the initial avoided cost methodology determination process, MPSC Staff recommends that each utility file a separate case before the Commission, but instead of conducting each such case separately the MPSC conduct three consolidated cases to address: (i) In-State Utilities without all-requirements Purchase Obligations; (ii) In-State Utilities with all-requirements Purchase Obligations; and (iii) Multi-State Utilities. While the Company appreciates that circumstances may affect the three groups of utilities in different ways, we disagree that separate contested cases should be conducted. The Company therefore recommends that the Commission conduct a single consolidated contested case to establish an avoided cost methodology applicable to all utilities that accommodates any special circumstances in an equitable manner.

The MPSC Staff biennial process recommendation appears to serve two purposes: (i) provide a basis for updating the standard contract terms that apply to QFs of 100 kilowatts (“kW”) or less and (ii) provide a basis for updating the avoided cost calculation to be used in any new contract to be negotiated in the subsequent two year period. MPSC Staff recommends that each utility file its respective case and then determine if any intervener requests a contested case. The Company believes that the biennial process should be conducted as an expedited contested proceeding because the matters to be addressed in this update proceeding are administrative in nature.

In addition to the above, the Draft Report discusses the approval process for QF Power Purchase Agreements (“PPA”) which incorporate the avoided cost methodology ultimately set by the Commission. MPSC Staff recommends approval during part of an *ex parte* filing or contested case proceeding depending on the Commission’s determination. The Company believes that it would not be an efficient use of the Commission’s resources to approve such QF PPAs as part of contested case proceedings. The use of contested case proceedings in these situations would cause unnecessary delay in the approval process and could complicate capacity planning and generator financing. Furthermore, contested case proceedings could needlessly duplicate the contested proceedings which will occur in the avoided cost methodology case. Therefore, the Company continues to support *ex parte* approval of all QF PPA’s which incorporate the avoided cost methodology ultimately set by the Commission.

Goal 2 – Determine Potential Methodologies for Determining Avoided Cost to be Paid to PURPA QFs

The Draft Report identified six basic methods for determining avoided cost, including the Proxy Unit method that has been widely used in Michigan for the last 35 years. Additionally, MPSC Staff presents a Modified Proxy Plant Method that combines elements of the Proxy Unit Methodology and Market Based Pricing Methodology as a strawman proposal and its recommendation for adoption by the MPSC.

Goal 3 – Develop a Recommendation on the Process and Methodology to be used in Establishing and Approving Avoided Costs to be Paid to QFs

While we appreciate the effort and rationale supporting MPSC Staff's recommendation, we have significant concerns using this approach. MPSC Staff's recommendation regarding the methodology for determining Avoided Cost to be paid to QFs is inconsistent with PURPA and is likely to result in higher cost to customers than authorized by PURPA.

A. PURPA Requirements:

The regulations for implementing the Public Utility Regulatory Policies Act of 1978 ("PURPA") are set forth in Title 18, Chapter I, Subchapter K, Part 292 of the Code of Federal Regulations ("CFR"). The principal requirements of these regulations for purposes of establishing avoided costs are as follows:

1. Avoided costs are defined as: "the **incremental** costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility **would** generate itself or purchase from another source." 18 CFR §292.101(b)(6) (emphasis added).
2. Utilities are required to provide to its State regulatory authority, and shall maintain for public inspection estimated capacity costs at completion of the planned capacity additions and planned capacity firm purchases, on the basis of dollars per kilowatt, and the associated energy costs of each unit, expressed in cents per kilowatt hour. 18 CFR §292.302(b)(3).
3. Power purchase rates shall:
 - a. Be **just and reasonable to the electric consumer** of the electric utility and **in the public interest**; and
 - b. Not discriminate against qualifying cogeneration and small power production facilities.
 - c. **Not require any electric utility to pay more than the avoided costs for purchases.** 18 CFR §292.304(a) (emphasis added).
4. Power purchase rates based on estimates of avoided costs do not violate (3) above if such rates differ from avoided costs at the time of delivery. 18 CFR §292.304(b)(5).
5. Standard rates for purchases are to be put into effect for Qualifying Facilities (QFs) with a design capacity of 100 kW or less. 18 CFR §292.304(c).
6. Each QF has the option:
 - a. To provide energy as the QF determines such energy to be available for such purchases, in which case the rates for such purchases shall be based on the purchasing utility's avoided costs calculated at the time of delivery; or
 - b. To provide energy or capacity pursuant to a legally enforceable obligation for the delivery of energy or capacity over a **specified term**, in which case the rates for such purchases shall, at the option of the qualifying facility exercised prior to the beginning of the specified term, be based on either:
 - i. The avoided costs calculated at the time of delivery; or

- ii. The avoided costs calculated at the time the obligation is incurred. See 18 CFR §292.304(d) (emphasis added).
7. In determining avoided costs, the following factors shall, **to the extent practicable**, be taken into account:
- a. The estimated avoided costs provided by each utility in accordance with 18 CFR §292.302;
 - b. The availability of capacity or energy from a qualifying facility during the system daily and seasonal peak periods, including:
 - i. The ability to dispatch the qualifying facility;
 - ii. The reliability of the qualifying facility;
 - iii. The terms of any contract or other legally enforceable obligation, including the duration of the obligation, termination notice requirement and sanctions for noncompliance;
 - iv. The extent to which scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the utility's facilities;
 - v. The usefulness of energy and capacity supplied from a qualifying facility during system emergencies, including its ability to separate its load from its generation;
 - vi. The individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system; and
 - vii. The smaller capacity increments and the shorter lead times available with additions of capacity from qualifying facilities; and
 - c. The relationship of the availability of energy or capacity from the qualifying facility as derived in (b) above, to the ability of the electric utility to avoid costs, including the deferral of capacity additions and the reduction of fossil fuel use; and
 - d. The costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a qualifying facility, if the purchasing electric utility generated an equivalent amount of energy itself or purchased an equivalent amount of electric energy or capacity. See 18 CFR §292.304(3) (emphasis added).

B. Intent of FERC's Regulations:

It is important to know how the Federal Energy Regulatory Commission ("FERC") originally intended the foregoing regulations be understood. On February 19, 1980, in Docket No. RM79-55, FERC issued Order 69 that formally adopted the regulations implementing PURPA. Highlighted below are portions of FERC's discussion on PURPA's requirements and its adopted regulations:

§292.101 Definitions.

“ In the proposed rule, subparagraph (6) defined ‘avoided costs’ as the costs to an electric utility of energy or capacity or both which, but for the purchase from a qualifying facility the electric utility would generate or construct itself or purchase from another source.

This definition is derived from the concept of ‘the incremental cost to the electric utility of alternative electric energy’ set forth in section 210 (d) of PURPA. It includes both the fixed and the running costs of an electric utility system which can be avoided by obtaining energy or capacity from qualifying facilities.

* * *

“If, by purchasing electric energy from a qualifying facility, a utility can reduce its energy costs or can avoid purchasing energy from another utility, the rate for a purchase from a qualifying facility **is to be based on those energy costs which the utility can thereby avoid.** If a qualifying facility offers energy of sufficient reliability and with sufficient legally enforceable guarantees of deliverability to permit the purchasing electric utility to avoid the need to construct a generating unit, to build a smaller, less expensive plant, or to reduce firm power purchases from another utility, **then the rates for such a purchase will be based on the avoided capacity and energy costs.**”

“The Commission has added the term ‘incremental’ to modify the costs which an electric utility would avoid as a result of making a purchase from a qualifying facility. Under the principles of economic dispatch, utilities generally turn on last and turn off first their generating units with the highest running cost. At any given time, an economically dispatched utility can avoid operating its highest-cost units as a result of making a purchase from a qualifying facility. The utility’s avoided incremental cost (and not average system costs) should be used to calculate avoided costs. With regard to capacity, if a purchase from a qualifying facility permits the utility to avoid the addition of new capacity, then the avoided cost of the new capacity and not the average embedded system cost of capacity should be used.

Many comments noted that the definition of "avoided cost" in the proposed rule failed to link the capacity costs which a utility might avoid as a result of purchasing electric energy or capacity or both from a qualifying facility with the energy costs associated with the new capacity. **If the Commission required electric utilities to base their rates for purchases from a qualifying facility on the high capital or capacity cost of a base load unit and, in addition, provided that the rate for the avoided energy should be based on the high energy cost associated with a peaking unit, the electric utilities' purchased power expenses would exceed the incremental cost of alternative electric energy, contrary to the limitation set forth in the last sentence of section 210(b)."**
FERC Order 69, 45 Fed. Reg. 12214,
12226, February 25, 1980 (emphasis added).

§292.301 Scope.

“The Commission interprets its mandate under section 210(a) to prescribe ‘such rules as it determines necessary to encourage cogeneration and small power production ...’... **to mean that the total costs to the utility and the rates to its other customers should not be greater than they would have been had the utility not made the purchase from**

the qualifying facility or qualifying facilities.” FERC Order 69, 45 Fed. Reg. 12214, 12217-12218, February 25, 1980 (emphasis added).

§292.302 Availability of electric utility system cost data.

“The Commission points out that the determination of a rate for purchases from a qualifying facility which enables a utility to defer or avoid the addition of a new unit **must also reflect the hours of expected use of the deferred or avoided capacity addition.**” FERC Order 69, 45 Fed. Reg. 12214, 12218, February 25, 1980 (emphasis added).

§§ 292.304(b)(5) and (d) Legally enforceable obligations

“Paragraphs (b)(5) and (d) are intended to reconcile the requirement that the rates for purchases equal the utilities’ avoided cost with the need for qualifying facilities to be able to enter into contractual commitments based, by necessity, on estimates of future avoided costs. Some of the comments received regarding this section stated that, if the avoided cost of energy at the time it is supplied is less than the price provided in the contract or obligation, the purchasing utility would be required to pay a rate for purchases that would subsidize the qualifying facility at the expense of the utility's other ratepayers. The Commission recognizes this possibility, but is cognizant that in other cases, the required rate will turn out to be lower than the avoided cost at the time of purchase. The Commission does not believe that the reference in the statute to the incremental cost of alternative energy was intended to require a minute-by-minute evaluation of costs which would be checked against rates established in long term contracts between qualifying facilities and electric utilities.” FERC Order 69, 45 Fed. Reg. 12214, 12224, February 25, 1980.

“The Commission intends that rates for purchases be based, at the option of the qualifying facility, on either the avoided costs at the time of delivery or the avoided costs calculated at the time the obligation is incurred. This change enables a qualifying facility to establish a fixed contract price for its energy and capacity at the outset of its obligation or to receive the avoided costs determined at the time of delivery.” FERC Order 69, 45 Fed. Reg. 12214, 12224, February 25, 1980.

§292.304(c) Factors affecting rates for purchases

Capacity Value.

“An issue basic to this paragraph is the question of recognition of the capacity value of qualifying facilities.

In the proposed rule, the Commission adopted the argument set forth in the Staff Discussion Paper that **the proper interpretation of section 210(b) of PURPA requires that the rates for purchases include recognition of the capacity value provided by qualifying cogeneration and small power production facilities.** The Commission noted

that language used in section 210 of PURPA and the Conference Report as well as in the Federal Power Act supports this proposition.” FERC Order 69, 45 Fed. Reg. 12214, 12225, February 25, 1980 (emphasis added).

§292.304(e) Factors affecting rates for purchases

“Clause (vi) refers to the aggregate capability of capacity from qualifying facilities to displace planned utility capacity. **In some instances, the small amounts of capacity provided from qualifying facilities taken individually might not enable a purchasing utility to defer or avoid scheduled capacity additions. The aggregate capability of such purchases may, however, be sufficient to permit the deferral or avoidance of a capacity addition.** Moreover, while an individual qualifying facility may not provide the equivalent of firm power to the electric utility, the diversity of these facilities may collectively comprise the equivalent of capacity.” FERC Order 69, 45 Fed. Reg. 12214, 12227, February 25, 1980 (emphasis added).

§292.308 Standards for operating reliability

“Section 210(a) of PURPA states that the rules requiring electric utilities to buy from and sell to qualifying facilities shall include provisions respecting minimum reliability of qualifying facilities (including reliability of such facilities during emergencies) and rules respecting reliability of electric utilities during emergencies. The Commission believes that the reliability of qualifying facilities can be accounted for through price; namely, the less reliable a qualifying facility might be, the less it should be entitled to receive for purchases from it by the utility.” FERC Order 69, 45 Fed. Reg. 12214, 12230, February 25, 1980 (emphasis added).

C. Conclusions Regarding the Requirements of PURPA

A number of conclusions can be drawn from the above examination of the PURPA regulations:

1. The avoided costs to be used to establish the payment rates to a QF are to be based on what the electric utility would actually plan to build or purchase to provide capacity and energy to its customers and what the QFs are actually able to help the electric utility avoid. Moreover, the avoided cost rates should be determined based on the best efforts to accurately reflect the electric utility’s avoided costs, notwithstanding the use of estimates.
2. Capacity rates should not be paid on the basis of per unit energy delivered, but on the per kW amount of capacity provided, as required to be provided by the utility, taking into account the reliability of the QF. As a result, it is important that capacity payments to QFs be based on the capacity credit provided to the utility by its reliability authority (e.g.; MISO’s² Zonal Resource Credits (“ZRC”)) which not only reflects the actual capacity credit that the electric utility can use to meet its reliability requirements, but also reflect the reliability of the resource.

² Midcontinent Independent System Operator, Inc.

3. Capacity rates should be based on the capacity that the electric utility is actually able to avoid building or purchasing from others by purchasing capacity from QFs instead.
4. Avoided cost rates should reflect when energy from the avoided resource would have been provided. Hence, if the avoided resource were, for example, a natural gas combined-cycle facility, the avoided cost rates should reflect the times when such a facility would be dispatched.
5. The energy payment rate should be linked to the avoided capacity resource. Consequently, if the avoided resource were, for example, a combustion turbine, the energy payments must be associated with the energy costs that the utility would have incurred had it installed a combustion turbine.
6. While FERC established an option for QFs to be paid on fixed, estimated costs, it did so based on the assumption that some estimates would be too high and an equal number of estimates would be too low and that the overall effect would be a balanced result. Thirty-six years later it is clear that FERC's assumption was erroneous as all of Consumers Energy's QF contracts have substantially exceeded market costs for the duration of their terms to-date. The Idaho Public Utilities Commission recently reached the same conclusion, stating "Based upon our record, we find that 20-year contracts exacerbate overestimations to a point that avoided cost rates over the long-term period are unreasonable and inconsistent with the public interest" (Order No. 33357, August 20, 2015).

Consumers Energy believes that Staff's estimated Natural Gas Combined Cycle ("NGCC") variable costs in the Draft Report's Figure 10 is a prime example of estimated costs that, if adopted, would result in significant payments in excess of the Company's avoided costs, even if it were assumed that the Company needs capacity and that the capacity it would need is an NGCC generating unit. Staff's fuel cost of \$5.01/MMBtu is substantially higher than Consumers Energy's projected fuel cost of less than \$3/MMBtu for 2016, so to the extent that Staff's estimate is in error (which we believe it is), that error will be systemic for the entire term of a contract. Moreover, since an NGCC only produces energy when it is economic to do so, paying the estimated variable costs for every megawatt-hour ("MWh") a QF produces will result in significantly more costs than what would be experienced if the energy produced by the QF would instead be purchased from the NGCC when the NGCC is economic and from the market when the NGCC is not economic.

Consequently (given FERC's expressed desire for reasonably achievable accuracy), since the nature of forecasted costs is to be too high, it is important to limit the length of contracts based on fixed, estimated costs to minimize the difference between forecast and actual avoided costs and ensure that the contract with the QF is just and reasonable and in the public interest. As a result, Consumers Energy recommends a maximum term of five (5) years for contracts under which all payment rates are based on fixed, estimated costs.

D. Draft Report Vs. PURPA

In light of the foregoing, this section will address how the proposals in the Draft Report meet the requirements of PURPA.

Act 295 of 2008 (“Act 295”) Transfer Price

While the Draft Report does not specifically propose Transfer Price as an avoided cost substitute to be used for purposes of PURPA, it is important to make it clear that the use of the Transfer Price does not satisfy PURPA’s requirements for the following reasons:

1. The Transfer Price method is not based on the actual capacity and energy costs avoided by the electric utility.
2. The Transfer Price method determines capacity costs based on all energy delivered from a renewable resource, ignoring when the proxy plant would actually deliver energy.
3. The Transfer Price method ignores whether the purchases by the utility from QFs could enable the utility to avoid the proxy plant.
4. The Transfer Price method requires customers to pay more than avoided costs.
5. The Act 295 Transfer Price and PURPA Avoided Costs are not analogous. The Transfer Price is used in Act 295 to allocate known costs between two different cost recovery mechanisms. As proposed in the context of the PURPA Avoided Cost determination, the Transfer Price method would be used to determine the price to be paid to QFs. The MPSC’s approval of the Transfer Price method in MPSC Case No. U-17321 did not contemplate use for this purpose. Additionally, reliance on the Transfer Price to determine Avoided Costs could become problematic if the Michigan Legislature were to repeal or amend the provisions of Act 295 which address the Transfer Price.

Staff’s Modified Proxy Plant Methodology (Staff’s Strawman)

Staff’s Strawman contains the same deficiencies as the Transfer Price, but also suffers from the additional deficiency of not linking the energy payment (uncapped locational marginal price (“LMP”) plus natural gas combined-cycle fixed incremental energy costs) to the resource providing capacity (combustion turbine). The linking of the energy and capacity payment is a factor that should be taken into consideration when establishing avoided costs.

Determination of Capacity Need

The Draft Report suggests that zonal capacity need be used to determine whether a capacity payment is required. This directly violates PURPA’s requirement that avoided costs be the avoided costs of the specific electric utility. Moreover, this exacerbates the subsidies provided by utility customers to Alternative Electric Suppliers (“AES”) in situations where the MISO zone is capacity deficient because one or more AES has secured insufficient resources and that shortfall causes a utility to pay for capacity it does not need.

The Draft Report also suggests capping the PURPA capacity purchase obligation by a percentage of total peak ZRC demand. This suggested limitation ignores the electric utility’s

actual capacity need and appears arbitrary. Moreover, the suggested calculation uses all current PURPA contract resources even though certain affected utilities have been exempted from future requirements to purchase from QFs of more than 20 megawatts (“MW”) in size.

Standard Offer Proposal

The Draft Report recommends that a standard rate be established and offered to all QFs that are 5 MW in size or smaller. Further the recommendation proposes to include the “full avoided cost capacity rate” in the standard offer. To the extent that standard offers are efficient in providing small QFs with access to avoided cost rates we recommend that standard offers attempt to utilize the determinants and replicate the resulting payment rates that the non-standard avoided cost methodology would produce at any given time. Further we recommend that the use of standard offers be limited to QFs capable of producing 0.1 ZRC or less, the minimum quantity recognized by MISO.

Capacity and Energy Options

It is unclear whether the proposed capacity options are intended to reflect the capacity credit that the utilities will actually receive from their reliability authorities. While the capacity options take care to reflect electric load carrying capability (“ELCC”), it is unclear whether the proposal intends to reflect the ELCC credited by the reliability authority or some other calculation of ELCC. For utilities in MISO, capacity payments should be based on the ZRCs credited to the QF. ZRCs are the units of measure for capacity used by MISO for the meeting of reliability requirements and reflect both ELCC (if applicable) and the reliability of the resource as required by PURPA.

By offering three options for energy payments, Staff’s Strawman ignores PURPA’s requirement that the energy payment be linked to the energy cost of the generating unit or purchase being avoided and would result in costs borne by utility customers that are above avoided costs. The following example illustrates the deficiencies of Staff’s Strawman and assumes that the Option 1 capacity payment and Option 3 energy payment is adopted as well as a \$3/MMBtu cost for gas.

Below is a one-day (January 2, 2007) snapshot that compares Staff’s Strawman for a 1.4 MW hydro plant against a scenario in which MISO ZRCs are used for capacity, the Staff’s capacity cost is based on ZRCs, and the energy price is the lower of LMP or the production cost of Staff’s combustion turbine (i.e., the actual avoided cost of a combustion turbine).

| 1.4 MW Hydro Example | | | | | | | | | | | | | | | | |
|----------------------|----------------|-------------------------|---------------------------|---------------|--------------------------|-------------------------|------------------------|------|------------------|--------------------------|---------------------------|---------------|--------------------------|-------------------------|------------------------|--|
| Hour | Capacity | | Capacity Payment \$ | Energy | | Energy Payment \$ | Total Payment \$ | Hour | Capacity | | Capacity Payment \$ | Energy | | Energy Payment \$ | Total Payment \$ | |
| | Capacity MW | Hourly Rate \$/MW | | Energy MWh | Energy Rate \$/MWh | | | | Capacity ZRCs | Hourly Rate \$/ZRC | | Energy MWh | Energy Rate \$/MWh | | | |
| 1 | 1.4 | 10.79 | 15.11 | 1.262 | 36.79 | 46.43 | 61.54 | 1 | 0.8 | 11.44 | 9.15 | 1.262 | 19.59 | 24.72 | 33.87 | |
| 2 | 1.4 | 10.79 | 15.11 | 1.263 | 36.79 | 46.47 | 61.58 | 2 | 0.8 | 11.44 | 9.15 | 1.263 | 23.79 | 30.05 | 39.2 | |
| 3 | 1.4 | 10.79 | 15.11 | 1.267 | 36.79 | 46.61 | 61.72 | 3 | 0.8 | 11.44 | 9.15 | 1.267 | 20.87 | 26.44 | 35.59 | |
| 4 | 1.4 | 10.79 | 15.11 | 1.268 | 36.79 | 46.65 | 61.76 | 4 | 0.8 | 11.44 | 9.15 | 1.268 | 22.58 | 28.63 | 37.78 | |
| 5 | 1.4 | 10.79 | 15.11 | 1.27 | 36.79 | 46.72 | 61.83 | 5 | 0.8 | 11.44 | 9.15 | 1.27 | 22.33 | 28.36 | 37.51 | |
| 6 | 1.4 | 10.79 | 15.11 | 1.27 | 36.79 | 46.72 | 61.83 | 6 | 0.8 | 11.44 | 9.15 | 1.27 | 29.25 | 37.15 | 46.3 | |
| 7 | 1.4 | 10.79 | 15.11 | 1.271 | 36.79 | 46.76 | 61.87 | 7 | 0.8 | 11.44 | 9.15 | 1.271 | 29.25 | 37.18 | 46.33 | |
| 8 | 1.4 | 10.79 | 15.11 | 1.271 | 36.79 | 46.76 | 61.87 | 8 | 0.8 | 11.44 | 9.15 | 1.271 | 29.25 | 37.18 | 46.33 | |
| 9 | 1.4 | 10.79 | 15.11 | 1.271 | 36.79 | 46.76 | 61.87 | 9 | 0.8 | 11.44 | 9.15 | 1.271 | 29.25 | 37.18 | 46.33 | |
| 10 | 1.4 | 10.79 | 15.11 | 1.257 | 36.79 | 46.25 | 61.36 | 10 | 0.8 | 11.44 | 9.15 | 1.257 | 29.25 | 36.77 | 45.92 | |
| 11 | 1.4 | 10.79 | 15.11 | 1.254 | 36.79 | 46.13 | 61.24 | 11 | 0.8 | 11.44 | 9.15 | 1.254 | 29.25 | 36.68 | 45.83 | |
| 12 | 1.4 | 10.79 | 15.11 | 1.253 | 36.79 | 46.1 | 61.21 | 12 | 0.8 | 11.44 | 9.15 | 1.253 | 28.01 | 35.1 | 44.25 | |
| 13 | 1.4 | 10.79 | 15.11 | 1.254 | 36.79 | 46.13 | 61.24 | 13 | 0.8 | 11.44 | 9.15 | 1.254 | 29.04 | 36.42 | 45.57 | |
| 14 | 1.4 | 10.79 | 15.11 | 1.256 | 36.79 | 46.21 | 61.32 | 14 | 0.8 | 11.44 | 9.15 | 1.256 | 29.25 | 36.74 | 45.89 | |
| 15 | 1.4 | 10.79 | 15.11 | 1.256 | 36.79 | 46.21 | 61.32 | 15 | 0.8 | 11.44 | 9.15 | 1.256 | 22.94 | 28.81 | 37.96 | |
| 16 | 1.4 | 10.79 | 15.11 | 1.254 | 36.79 | 46.13 | 61.24 | 16 | 0.8 | 11.44 | 9.15 | 1.254 | 22.23 | 27.88 | 37.03 | |
| 17 | 1.4 | 10.79 | 15.11 | 1.257 | 36.79 | 46.25 | 61.36 | 17 | 0.8 | 11.44 | 9.15 | 1.257 | 21.37 | 26.86 | 36.01 | |
| 18 | 1.4 | 10.79 | 15.11 | 1.258 | 36.79 | 46.28 | 61.39 | 18 | 0.8 | 11.44 | 9.15 | 1.258 | 29.25 | 36.8 | 45.95 | |
| 19 | 1.4 | 10.79 | 15.11 | 1.258 | 36.79 | 46.28 | 61.39 | 19 | 0.8 | 11.44 | 9.15 | 1.258 | 29.25 | 36.8 | 45.95 | |
| 20 | 1.4 | 10.79 | 15.11 | 1.259 | 36.79 | 46.32 | 61.43 | 20 | 0.8 | 11.44 | 9.15 | 1.259 | 29.25 | 36.83 | 45.98 | |
| 21 | 1.4 | 10.79 | 15.11 | 1.258 | 36.79 | 46.28 | 61.39 | 21 | 0.8 | 11.44 | 9.15 | 1.258 | 29.25 | 36.8 | 45.95 | |
| 22 | 1.4 | 10.79 | 15.11 | 1.259 | 36.79 | 46.32 | 61.43 | 22 | 0.8 | 11.44 | 9.15 | 1.259 | 29.25 | 36.83 | 45.98 | |
| 23 | 1.4 | 10.79 | 15.11 | 1.259 | 36.79 | 46.32 | 61.43 | 23 | 0.8 | 11.44 | 9.15 | 1.259 | 29.25 | 36.83 | 45.98 | |
| 24 | 1.4 | 10.79 | 15.11 | 1.259 | 36.79 | 46.32 | 61.43 | 24 | 0.8 | 11.44 | 9.15 | 1.259 | 21.3 | 26.82 | 35.97 | |
| | | | | | | | \$1,476.05 | | | | | | | | \$1,019.46 | |

As illustrated by the example above, Staff’s Strawman would result in about a 45% overpayment to the QF because: 1) run-of-river hydro plant capacity is generally less valuable than the proxy unit capacity; and 2) on this particular day the proxy unit was not economic to dispatch. The proxy plant chosen by MPSC Staff was uneconomic to dispatch about 35% of the time before adding the “NGCC Fixed Investment Cost Attributable to Energy” adjustment.

Fixed Investment Cost Attributable to Energy

Staff’s Strawman assumes that market energy prices are tempered by lower energy costs from natural gas combined-cycle facilities. In other words, while the capacity markets base capacity deficiency costs on combustion turbine facilities, the actual capacity being installed is from combined-cycle facilities and the energy markets actually reflect combined-cycle facility operation. It appears that Staff believes that the avoided capacity resource is a combined-cycle facility, but wants to implement that belief in a way that resembles how the market is operating today. The Company believes that it would be more reasonable and straight-forward to use a combined-cycle facility as the avoided capacity resource and use the lower of LMP and the dispatch cost of a combined-cycle facility. This particular attribute of Staff’s Strawman fails to properly consider the link between the energy payment with the avoided capacity resource and also inappropriately uses per kW fixed costs on a per kWh basis.

Barriers to QF Participation in RTO/ISO Markets

The Draft Report indicates that there are financial and technical barriers for QF participation in Regional Transmission Organization/Independent System Operator (“RTO/ISO”) markets. Consumers Energy does not agree. Nonetheless, Consumers Energy is willing to provide QFs of 20 MW or less in size and interconnected to the Company’s distribution system free access to the MISO market (i.e., register the QF in the market and transfer market payments to the QFs). The QF will be required to accept the LMP and Auction Clearing Price (“ACP”) determined at the time of delivery for energy and capacity as the Avoided Cost under such an arrangement. However; the QF then has access to markets the same as any other market participant.

Presence of Alternate Electric Suppliers

Consumers Energy is generally in agreement with the Draft Report’s discussion regarding AESs. PURPA should not cause the loss of additional load to AESs as long as purchases made pursuant to it are at avoided cost and the avoided cost reflect market prices. The Company strongly agrees that AESs or their customers should share in the over-market costs that have resulted from PURPA’s mandatory purchase obligation. One mechanism available to the MPSC to address this issue is to allow utilities that record QF expense greater than market to recognize that above market expense as a non-by-passable cost of providing distribution service.

Ancillary Services

To the extent that a QF can provide ancillary services that can actually be sold into the RTO/ISO markets, Consumers Energy believes that the QF should receive the appropriate revenue for the service provided. The Company does not agree, however, that QFs should be paid for services for which there is no market since that would likely result in customers paying twice for the same service (e.g., performance and ramping services are likely captured in Revenue Sufficiency Guarantee and Regulation charges and Black Start is a transmission requirement which is likely captured in transmission service charges). A QF with Black Start capabilities is free to become an Independent Power Producer, file a tariff with FERC, and establish the cost based rate it is entitled to recover for providing Black Start services. The Company is not aware of a rule that would entitle a utility to file a cost based tariff for a QF Black Start facility based on an estimate of the cost based rate the proxy plant would be entitled to receive.

Renewable Energy Credits and Environmental Attributes

Consumers Energy continues to rely on its earlier comments provided to Staff regarding renewable energy credits (“REC”) and environmental attributes. RECs should belong to the utility. The reason a utility and its customers have a must purchase obligation is because of the use of "qualifying" technology. To the extent that a facility qualifies because it is renewable, the utility should receive the RECs. Regarding CO₂ attributes, there is substantial uncertainty how current proposed rules will be implemented, therefore, to the extent that the utility's purchase from a QF results in additional carbon emissions that the utility would

otherwise avoid or additional energy expense, the utility should be awarded the carbon allowances.

Avoided Transmission Costs and Avoided Line Losses

Consumers Energy agrees with the Draft Report’s conclusion that transmission costs and line loss mitigation not be included in the avoided cost calculation at this time. This conclusion is consistent with PURPA’s guidance that such considerations be “practicable.”

Contract Length

The Draft Report proposes that contracts have a term that spans the shorter of either the QF financing period or 17.5 years for new QFs. Consumers Energy believes that Act 81 was intended to address QF contracts that were already in effect when the Act was passed into law (hence the reference in Act 81 to “previously approved capacity charges”) and should not be a basis for establishing term length for new contracts since at the time new contracts are executed no capacity charges will have been approved. Moreover, as the Company stated previously, long-term contracts using fixed, estimated costs have shown such estimates to be substantially in excess of actual costs. Consumers Energy agrees with the Idaho Public Utilities Commission statement in its August 20, 2015, Order No. 33357:

“We find shorter contracts reasonable and consistent with federal and state law for multiple reasons. First, shorter contracts have the potential to benefit both the QF and the ratepayer. By adjusting avoided cost rates more frequently, avoided costs become a truer reflection of the actual costs avoided by the utility and allow QFs and ratepayers to benefit from normal fluctuations in the market.

“Second, shorter contract lengths do not ultimately prevent a QF from selling energy to a utility over the course of 20 years — or longer. PURPA’s “must purchase” provision requires the utility to continue to purchase the QF’s power. As long as projects continue to offer power to utilities, utilities must continue to purchase such power under PURPA. A shorter contract length merely functions as a reset for calculation of the avoided costs in order to maintain a more accurate reflection of the actual costs avoided by the utility over the long term.” (Page 24).

Goal 4 - Determine if Support for the Recommendation is a Consensus or if Alternate Recommendations are Supported

In the Company’s February 23, 2016 Letter (Appendix C, page 1 through 4), the Company discusses the need to provide a flexible mechanism to determine avoided costs depending on the amount of capacity deficiency expected to be addressed over the planning horizon. While the methodology proposed by the Company has the potential to be more complex than the MPSC Staff’s Strawman Proposal, it provides for some judgement to apply the right solution to the right set of facts, a process that the regulatory process is adept at executing.

Conclusion:

Consumers Energy finds the strawman proposals contained in the Draft Report to be inconsistent with the requirements of PURPA and believes that implementing such proposals will result in higher costs to our customers than an approach which is consistent with PURPA's requirements and which properly considers the impacts on customers. We recommend the Commission to adopt an approach similar to the approach contained in the Company's February 23, 2016 Letter contained in Appendix C, page 1 through 4 of the Draft Report.

Respectfully,



David F. Ronk, Jr.

Executive Director – Transactions and Wholesale Settlements
Consumers Energy Company



April 1, 2016

Mr. Paul Proudfoot
Director – Electric Reliability Division
Michigan Public Service Commission
7109 W. Saginaw Highway
Lansing, MI 48917

**Re: MPSC Case No. U-17973
PURPA Technical Advisory Committee
Report on the Continued Appropriateness of the
Commission’s Implementation of PURPA**

Dear Mr. Proudfoot:

DTE Electric (DTE) hereby submits the following comments regarding the MPSC Staff’s (Staff) draft Technical Advisory Committee Report (Draft Report) that was provided to participating parties for review on March 15, 2016. Staff requested that comments be submitted to Staff by April 1, 2016 for consideration in their Final Technical Advisory Committee Report which would then be posted on the PURPA TAC website and filed in the docket for Case U-17973.

As a preliminary matter, DTE would like to recognize and commend the efforts of the Commission’s Electric Reliability Division in carrying out the directives of the Commission in their October 27, 2015 Order in Case U-17973. Within that Order the Commission directed Staff to commence the process of forming a Technical Advisory Committee (TAC) to assess the continuing appropriateness of the Commission’s current regulatory construct regarding the Public Utility Regulatory Policies Act of 1978 (PURPA). The Staff facilitated the creation of the TAC and conducted 5 meetings between December 2015 and March 2016. Despite

substantive differences of opinion within the TAC on some issues, the Staff conducted the meetings in a transparent, inclusive, and professional manner.

While DTE agrees with a number of the conclusions of the Draft Report, our comments will focus on the primary issues we believe require additional consideration at this point in time. Failure to address a particular issue should not be construed as DTE's agreement on that issue and DTE reserves its right to contest any matter in this proceeding or other proceedings.

DTE Focus

The Draft Report identifies that a contributing factor to the Commission's October 27, 2015 Order in Case U-17973 was the expiration of certain existing PURPA contracts and the inquiry of potential new qualifying facilities (QFs) about avoided costs and other factors. DTE currently has 12 active PURPA contracts, the first of which expires in 2023. Only 4 contracts will expire before 2030. While we recognize that the near term resolution and timing of issues in the contract renewal process is extremely important to those parties involved with expiring contracts, DTE's focus in the TAC is directed towards forward looking capacity and energy need issues relative to PURPA.

Supply Adequacy and Purchase Obligation

The nature of (and limitations upon) any utility obligation to purchase capacity, energy, or both from QFs at the utility's avoided cost pursuant to PURPA, was discussed during the TAC meetings. DTE firmly believes that PURPA imposes no obligation on an electric utility to purchase QF capacity when that electric utility does not need capacity to serve its retail customers. If a utility has adequate capacity to serve its retail customers, any obligation to purchase is, at most, limited to energy only. Furthermore, any capacity or energy supplied by a QF is to be priced at the utility's avoided cost and be just and reasonable to the electric consumers of the electric utility. PURPA defines avoided costs as:

“the **incremental** costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying

facility or qualifying facilities, such utility **would** generate itself or purchase from another source.” (§292.101(b)(6), emphasis added).

A paramount consideration in developing any new PURPA policy in Michigan must be the hybrid Electric Choice Program. Nominally, 10 percent of the retail electric load within the DTE and Consumers Energy service territories participate in the Electric Choice Program where those retail customers receive their electric supply directly from alternative electric suppliers (AESs). While the continuation of, or modifications to that program are currently the subject of legislative discussions, DTE has stated within the context of the TAC meetings that the need for utility capacity in PURPA discussions should be limited to the provision of supply to full service retail customers only, while the Electric Choice Program continues to exist. DTE would submit that the creation of the hybrid Electric Choice Program in Michigan is the most significant change affecting need for capacity discussions in Michigan since the Commission initially dealt with PURPA implementation in the U-6798 et.al. cases. The Draft Report recognizes the existence of the Electric Choice program in Michigan and the possibility that, absent the current statutory cap, utilities could be susceptible to losing additional load to an AES if obligatory PURPA purchases were to cause the utilities’ rates to increase. DTE strongly agrees. However, the resultant Staff recommendation only suggests that the Commission may want to consider passing on some costs paid by utilities under the PURPA mandatory purchase obligation to AESs.

Within the context of this PURPA review process, DTE strongly recommends that the Commission find that electric utilities affected by Electric Choice have no obligation to purchase capacity for distribution load being served by an AES. DTE currently believes that it will have sufficient supply resources to reliably serve full service retail load in the near term of the 10 year PURPA planning horizon suggested in the Draft Report. This should obviate the need for any new obligatory capacity purchase during those years when sufficient resources exist.

Given the current debate on the need for capacity in Michigan, AES's could and should have the same types of obligations as electric utilities with respect to any obligatory PURPA purchases. The Draft Report recommends the use of a 10 year planning horizon and suggests that zonal capacity need, in contrast to a utility-specific capacity need, be a primary consideration when determining the initiation of the capacity payments for PURPA purchases. DTE would disagree. Acceptance of that consideration would result in the imposition of an obligation to purchase and pay for PURPA capacity on utilities that have sufficient capacity during periods when the broader MISO Zone 7 (Zone 7) was determined to be short of capacity. Customers of the capacity sufficient utility would then be required to pay higher rates for the obligatory purchase even though the triggering Zone 7 capacity deficiency was caused by other load serving entities, including AESs. DTE believes that the other load serving entities contributing to or causing a capacity deficiency within Zone 7 should bear any purchase obligation.

The current capacity debate in Michigan also begs for consistency of method going forward to avoid confusion and methodological conflicts. Recognizing the multiplicity of discussions within the legislature and the MPSC (avoided cost and five year reviews), DTE believes that the revised PURPA process should use the MISO construct. The MISO construct breaks up the total zone, such as Zone 7, into subzones or local resource zones (LRZ). Within that LRZ the process then focuses each load serving entity within the LRZ and the resources that they have available to serve their expected need. Resultant shortfalls could be used to determine purchase obligations for non-regulated load serving entities, such as AES's. Finally, the Draft Report proposes three capacity payment options going forward for QFs larger than 5 MW and not larger than 20 MW. Each of the 3 pricing options again rely on a forward looking 10 year PURPA planning horizon to establish capacity need. It appears the Staff in the case of each of the three pricing options recommends use of utility-specific capacity needs and LRZ to establish need for capacity. It is not clear how this relates to Staff's earlier suggested approach to use Zone 7 capacity need as a primary consideration for the initiation of a capacity

payment requirement when using the 10 year PURPA planning horizon. DTE would request clarification on whether Staff is referring to the utility-specific capacity needs and LRZ or the broader zonal approach. This clarification is critical because the subsequent Administrative Process (Figure 3) recommends the Commission issue an Order directing the utilities to file avoided cost calculations and avoided cost data according to the Staff Recommended Proposal.

DTE would reiterate that any capacity purchase obligations cannot lawfully begin for a load serving entity until capacity is actually needed by that load serving entity within the LRZ. For new contracts, if capacity is not needed by the load serving entity at the time the contract is signed, the capacity payment should be zero. The Draft Report also appears to imply that, if capacity is needed at any point within the 10 year planning horizon, capacity payments should be paid for the entire period. DTE disagrees. Any obligatory payments made by electric utilities that have no local need for capacity violates PURPA, creates subsidies for developers, and results in higher rates for full retail service customers.

Energy and Capacity Payments

Staff's Strawman proposal recommends that capacity payments be based on a natural gas simple cycle combustion turbine (CT) with an Effective Load Carrying Capability (ELCC) applied to address the value of different generation types. DTE supports the application of an ELCC to the capacity payment and believes it is necessary to reflect the value the capacity is credited for in reliability planning requirements. DTE believes that unit reliability should also be taken into consideration when determining capacity value as that is what is done for reliability planning requirements.

Staff's Strawman proposal further recommends that energy prices be based on the wholesale energy market locational marginal prices (LMPs) with an adder (referred to as investment cost attributable to energy (ICE)) based on the fixed capacity cost difference between a natural gas combined cycle (NGCC) and CT. This concept is

flawed because the fixed capacity cost difference (or ICE) is in units of \$/kWh based on the expected output of a NGCC (61.77% capacity factor (CF) in Staff's example) then applied in the same units to the energy output of other generation technologies with very different CFs which can result in significant over/under payment. This methodology is overly complicated and incorrect. DTE understands the driver behind Staff's methodology. It is the crux of the current unreasonable and unjust AES free-riding that is occurring in Michigan. AESs are benefitting from the low capacity costs in the market (currently due to excess capacity) and capped by market rules at the lower capacity cost of a CT. Then they are benefitting from the lower costs of energy primarily based on frequently dispatched cheaper generation like wind, nuclear, coal, and NGCC – not the higher energy cost of a CT. DTE believes that the more accurate and simpler solution is to base the capacity payment on a NGCC and the energy payment on the lower of the energy of a NGCC or the wholesale energy market locational marginal prices (LMPs). This "lower of" energy payment addresses the fact that PURPA resources generate energy whether it is economic or not because they are not dispatched by the independent system operator like the electric utilities' other generating resources. The method proposed in the Draft Report creates unnecessary additional cost for electric utility customers.

Standard Offer Rate

The Draft Report recommends an expanded standard offer size for QFs in Michigan of 5 MW and smaller. No justification or basis for the increase was provided in the Draft Report. DTE Electric would submit that this 50 time increase in the size limit appears excessive and would limit the ability of the utilities to recognize unit specific characteristics going forward when negotiating payments for avoided costs. In addition, it appears that the Draft Report recommends that the standard offer rate be offered at full avoided cost to QFs 5 MW and smaller during periods when the utility has no need for capacity. DTE Electric recommends that standard offer utility capacity payments need not be offered during periods when capacity is not needed by that utility.

Finally, Figure 3 of the Draft Report indicates that standard offer contracts may not need Commission approval. DTE Electric would request clarification on whether Staff was referencing the current 100 kw limit for standard offer contracts or suggesting that standard offer contracts of 5 MW and below may not need Commission approval.

MPSC Administrative Process for PURPA Reviews

DTE believes that if a utility has an obligation to purchase capacity, or energy, or both from a QF pursuant to PURPA it has the right to recover the costs for those purchases from customers pursuant to applicable state law. The operative statute relative to capacity purchases, which was aptly discussed in the Draft Report, is MCL 460.6j, as amended. It is clear that capacity purchases exceeding 6 months in length or capacity charges associated contracts from a QF require Commission approval to be recovered. MCL 460.6j also distinguishes between actual contract approvals and the power supply reconciliation process. DTE believes that necessary contract approvals should be accomplished outside power supply plan or reconciliation cases.

The Draft Report proposes a contested case process for Establishing a New Avoided Cost Methodology. DTE supports that recommendation to establish the basic ground rules for the revised PURPA avoided cost process going forward. Figure 3 estimates that the Commission could issue an Order in June 2016 directing the utilities to file avoided cost calculations and Section 292.302 avoided cost data according to the Staff Recommended Proposal and any additional calculation methodology requested by the utility. Figure 3 further estimates that the Commission could issue a final Order approving the new avoided cost methodology in April 2017. DTE would request a filing date no earlier than 60 days from the date of the Commission order requiring this filing. If DTE is ordered to file an avoided cost calculation using the Staff method it may likely file a second calculation using the Company's preferred method.

Conclusion

DTE believes that the Draft Report has certain recommendations that would unduly impact that rates of its retail customers if the Draft Report was adopted in its entirety. Those recommendations are identified within the body of these comments and DTE respectfully requests that they be given due consideration.

Respectfully submitted,

/s/ James R. Padgett

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Director, Electric Regulatory Strategy

Cc: Julie Baldwin
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Response to the Staff Draft Report for the PURPA-TAC

The Staff's April 8, 2016 Draft Report circulated to the PURPA-TAC group suggests that "[t]he commission may want to consider passing some costs paid by utilities under PURPA's mandatory purchase obligation onto AESs." Draft Report, p. 29. While Energy Michigan has not been a participant in this Workgroup, the above suggestion has been brought to our attention and is of concern to the association as it implies that customers of AESs are somehow not paying costs that should be appropriately assigned to them. We would like to provide the following in response to that suggestion.

The suggestion is based on an assumption that is contrary to the way PURPA works, stating, "If PURPA were to cause the cost of a utility's electricity to increase" Draft Report, p. 29. This assumption ignores the *savings* that the utility and its customers receive under a purchase from a QF. The savings are exactly the "avoided costs" that are paid to the QF. Utility customers and shareholders are exactly neutral with respect to a mandatory purchase from a QF because the utility pays the QF the costs it would otherwise have paid for new utility generation. Therefore, customers will pay the same either for new utility generation or for purchasing the equivalent supply from a QF.

Consequently, as long as the utility plans prudently and the Commission reviews and approves an avoided cost that truly reflects the savings to the utility, there are *no additional* costs to utility customers that are created by purchase from a QF

With this as backdrop, we are providing the following specific comments.

First, it would be inappropriate, and perhaps unlawful, for AESs to be required to pay for the must carry obligation that Federal law imposes on utilities. As Staff is aware, an AES is not a "utility" under state law and so is not subject to PURPA's must carry obligation and avoided cost payments.

Secondly, even if AESs were subject to the must carry obligation, and consequently had to pay for QF energy and possibly capacity, then what they would be paying would be their own avoided cost rate, and not that of a regulated utility. Therefore, allocating to AESs (were they somehow deemed to be a utility) a share of another utility's costs derived from the other utility's future plans would be contrary to PURPA's requirements and structure.

Finally, the Staff comments express concerns about stranded costs. As Energy Michigan has attested in both MPSC proceedings and in testimony before both houses of the Legislature, stranded costs for existing utility assets were all paid several times over when Michigan's electric market was restructured. Customers, including Choice customers, have only just stopped paying for those costs in the last year, and the utilities have not built any significant new base load capacity that would form the basis for new stranded costs. Should that happen, the utilities have already testified before House and Senate committees that they do not intend to build for the customers on Choice, so assigning those customers a share of the costs would be inappropriate and a violation of cost of service principles.

In short, Staff's suggestion that utilities should be permitted to shift their PURPA costs to AESs or their customers is inconsistent with the structure and function of PURPA, and without some preliminary showing that there are truly QF-related costs imposed on the utility by Choice customers, any attempt to shift costs onto those customers would be unlawful and inappropriate under state law as well.

Comments of EnStar Energy on the MPSC Staff's Draft Report on the Continued Appropriateness of the Commission's Implementation of PURPA

At the March 3, 2016 meeting of the PURPA Technical Advisory Committee the Commission Staff requested members of the Committee to review its draft report to the Commission and submit any comments they might have.

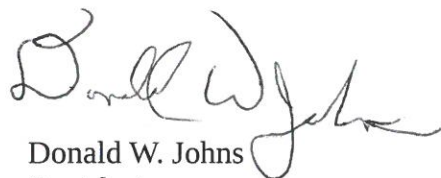
After reviewing the report, EnStar Energy sees a technical issue in one area of the report that will have a significant impact on the implementation of the Staff's recommendations if not corrected. To be specific, the Fixed Charge Rate set forth in Figure 9 on page 19 of the report of 9.30% does not appear to be the Fixed Charge Rate which would be appropriate for deriving the annual carrying cost of a natural gas fired combustion turbine using EIA data, but instead appears to be the weighted cost of capital which a utility would incur if constructing such generation. This same value was used again in Figure 11 on page 24 to derive the Fixed Cost Attributable to Energy based on the levelized incremental investment cost associated with an advanced (400 MW H class) Combined Cycle plant.

A true Fixed Charge Rate utilized to estimate the levelized capital cost of generation must contain all the charges that are a function of the capital investment in the generation facility. This includes not only, the weighted cost of debt and equity capital but also income taxes, property taxes, insurance and depreciation. An excerpt from a study defining this factor is attached.

In the current economic climate, the Fixed Charge Rate for Michigan Utilities such as Consumers Energy and Detroit Edison is likely to fall somewhere in the 15-17% range when investment tax credits and other factors are taken into account. A recent EIA study deriving the levelized cost of a Class F Combined Cycle Plant utilizes a Fixed Charge Rate (called a Capital Charge Factor in the study) of 16.4%. This value is consistent with Fixed Charge Rates used in such analyses and is approximately 43% higher than the Staff value of 9.30%. Accordingly, this will have a significant impact on the derivation of Avoided Costs for capacity using the proposed Avoided Plant Proxy recommended in the report as well as option 3 of the proposed energy payments set forth on page 21.

Given that the Staff appears to be utilizing similar EIA data in deriving its proposal, EnStar highly recommends that the source of its estimates for the Fixed Charge Rate be revisited prior to filing its report with the Commission. A 40% adjustment is significant but it will not change, in EnStar's view, the recommendations in the report which are otherwise well reasoned and should be adopted.

Thank you for the opportunity to participate in the TAC,



Donald W. Johns
President

Natural Gas Combined-Cycle Plants With and Without Carbon Capture & Sequestration

Technology Overview

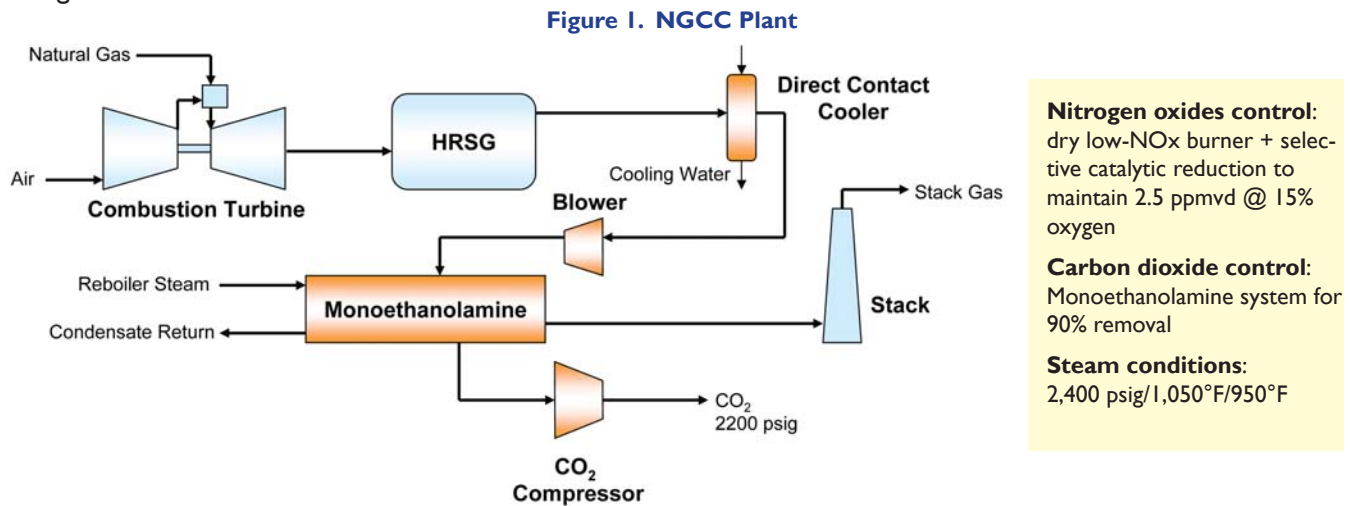
Two Natural Gas Combined-Cycle (NGCC) power plant configurations were evaluated, and the results are presented in this summary sheet. Both cases were analyzed using a consistent set of assumptions and analytical tools. The two configurations evaluated are based on an NGCC plant with and without carbon capture and sequestration (CCS).

- NGCC plant utilizing Advanced F-Class combustion turbine generators (CTGs).
- NGCC plant utilizing Advanced F-Class CTGs with CCS.

Each NGCC plant design is based on a market-ready technology that is assumed to be commercially available in time to support a 2010 startup date. The NGCC plants are built at a greenfield site in the midwestern United States and are assumed to operate in baseload mode at 85 percent capacity factor (CF) without sparing of major train components. Nominal plant size (gross rating) is 570 MWe without CCS and 520 MWe with CCS. All designs consist of two advanced F-Class CTGs, two heat recovery steam generators (HRSGs), and one steam turbine generator in a multi-shaft 2x2x1 configuration.

The NGCC cases were evaluated with and without CCS on a common thermal input basis. The case that includes CCS is equipped with the Fluor Econamine (FG) Plus™ process. The NGCC with CCS case also has a smaller plant net output resulting from the additional CCS facility auxiliary loads and steam consumption. After compression to pipeline specification pressure, the carbon dioxide (CO₂) is assumed to be transported to a nearby underground storage facility for sequestration.

The size of the NGCC designs was determined by the output of the commercially available combustion turbine. Therefore, evaluation of the NGCC designs on a common net output basis was not possible. For the cases with and without CCS, respective gross output was 520 and 570 MWe, and respective net output was 482 and 560 MWe. The natural gas (NG) flowrate was 165,182 lb/hr in both cases. See Figure 1 for a generic block flow diagram of an NGCC plant. The orange blocks in the figure represent the unit operations added to the configuration for CCS cases.



Orange blocks indicate unit operations added for CCS case.

Note: Diagram is provided for general reference of major flows only. For complete flow information, please refer to the final report.

Technical Description

The combined-cycle plant was based on two CTGs. The CTG is representative of the advanced F-Class CTGs with an International Standards Organization base rating of 184,400 kWe (when firing NG). This machine is an axial flow, single-shaft, constant-speed unit, with variable inlet guide vanes and Multi-Nozzle Quiet Combustor dry low-NOx (DLN) burner combustion system. Additionally, a selective catalytic reduction (SCR) system further reduces the nitrogen oxides (NOx) emissions. The Rankine cycle portion of both designs uses a single-reheat 16.5 MPa/566°C/510°C (2,400 psig/1,050°F/950°F) cycle. Recirculating evaporative cooling systems are used for cycle heat rejection. The efficiency of the case without CCS is almost 51 percent, with a gross rating of 570 MWe.

The CCS case requires a significant amount of auxiliary power and extraction steam for the process, which reduces the output of the steam turbine. This results in a lower net plant output for the CCS cases of about 482 MWe for an average net plant efficiency of almost 44 percent higher heating value (HHV).

The CCS case is equipped with the Fluor Econamine Flue Gas (FG) Plus™ technology, which removes 90 percent of the CO₂ in the FG exiting the HRSG unit. Once captured, the CO₂ is dried and compressed to 15.3 MPa (2,215 psia). The compressed CO₂ is transported via pipeline to a geologic sequestration field for injection into a saline formation, which is located within 50 miles of the plant. Therefore, CO₂ transport, storage, and monitoring costs are included in the analyses.

Fuel Analysis and Costs

The design NG characteristics are presented in Table 1. Both NGCC cases were modeled with the design NG.

A NG cost of \$6.40/MMkj (\$6.75/MMBtu) (January 2007 dollars) was determined from the Energy Information Administration AEO2007 for an eastern interior high-sulfur bituminous coal.

Environmental Design Basis

The environmental design for this study was based on evaluating both of the NGCC cases using the same regulatory design basis. The environmental specifications for a greenfield NGCC plant are based on the pipeline-quality NG specification in Table 1 and EPA 40 CFR Part 60, Subpart KKKK. Table 2 provides details of the environmental design basis for NGCC plants built at a midwestern U.S. location. The emissions controls assumed for each of the two NGCC cases are as follows:

- Dry low-NOx burners in conjunction with SCR for NOx control in both cases.
- Econamine process for CO₂ capture in the CCS case.

NGCC plants produce negligible amounts of SO₂, particulate matter (PM), and mercury (Hg); therefore, no emissions controls equipment or features are required for these pollutants.

Table 1. Fuel Analysis

| Natural Gas | | |
|----------------|--------------------------------|-------------------|
| Component | | Volume Percentage |
| Methane | CH ₄ | 93.9 |
| Ethane | C ₂ H ₆ | 3.2 |
| Propane | C ₃ H ₈ | 0.7 |
| n-Butane | C ₄ H ₁₀ | 0.4 |
| Carbon dioxide | CO ₂ | 1.0 |
| Nitrogen | N ₂ | 0.8 |
| Total | | 100.0 |
| | LHV | HHV |
| | kJ/kg | 47,764 |
| | kJ/scm | 35 |
| | Btu/lb | 20,552 |
| | Btu/scf | 939 |

Table 2. Environmental Targets

| Pollutant | NGCC |
|-----------------|------------------------|
| SO ₂ | Negligible |
| NOx | 2.5 ppmvd @ 15% Oxygen |
| PM (filterable) | Negligible |
| Hg | N/A |

Major Economic and Financial Assumptions

For the NGCC cases, capital cost, production cost, and levelized cost-of-electricity (LCOE) estimates were developed for each plant based on adjusted vendor-furnished and actual cost data from recent design/build projects and resulted in determination of a revenue-requirement 20-year LCOE based on the power plant costs and assumed financing structure. Listed in Table 3 are the major economic and financial assumptions for the two NGCC cases.

Project contingencies were added to each of the cases to cover project uncertainty and the cost of any additional equipment that could result from detailed design. The project contingencies represent costs that are expected to occur. Project contingency was 10.6 percent for the NGCC case without CCSTPC and roughly 13.3 percent for the NGCC case with CCS.

Process contingency is intended to compensate for uncertainties arising as a result of the state of technology development. Process contingencies have been applied to the estimates as follows:

- CO₂ Removal System – 20 percent on all NGCC CCS cases.
- Instrumentation and Controls – 5 percent on the NGCC CCS cases.

This study assumes that each new plant would be dispatched any time it is available and would be capable of generating maximum capacity when online. Therefore, CF is assumed to equal availability and is 85 percent for NGCC cases.

For the NGCC case that features CCS, capital and operating costs were estimated for transporting CO₂ to an underground storage field, associated storage in a saline aquifer, and for monitoring beyond the expected life of the plant. These costs were then levelized over a 20-year period.

Results

The results of the analysis of the two NGCC cases are presented in the following subsections.

Capital Cost

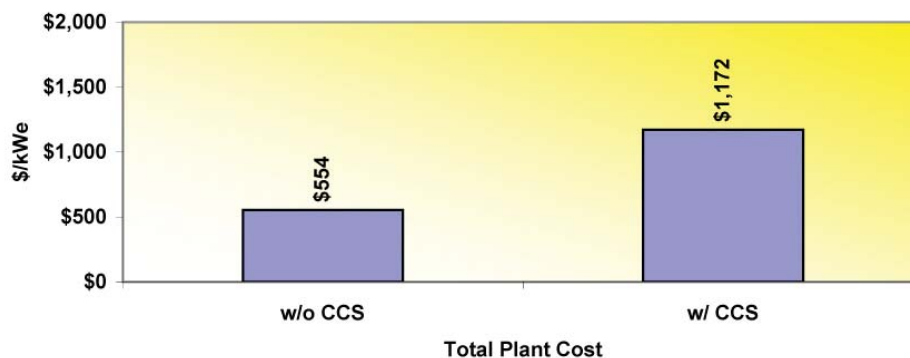
The total plant cost (TPC) for each of the two NGCC cases is compared in Figure 2. The TPC includes all equipment (complete with initial chemical and catalyst loadings), materials, labor (direct and indirect), engineering and construction management, and contingencies (process and project). Owner’s costs are not included.

The results of the analysis indicate that an NGCC costs \$554/kWe, and that an additional \$618/kWe is needed for the NGCC plant with CCS.

Table 3. Major Economic and Financial Assumptions for NGCC Cases

| Major Economic Assumptions | |
|-------------------------------------|------------------|
| Capacity factor | 85% |
| Costs year in constant U.S. dollars | 2007 (January) |
| Natural gas delivered cost | \$6.75/MMBtu |
| Construction duration | 3 Years |
| Plant startup date | 2010 (January) |
| Major Financial Assumptions | |
| Depreciation | 20 years |
| Federal income tax | 34% |
| State income tax | 6% |
| Low risk cases | |
| After-tax weighted cost of capital | 8.79% |
| Capital structure: | |
| Common equity | 50% (Cost = 12%) |
| Debt | 50% (Cost = 9%) |
| Capital charge factor | 16.4% |
| High risk cases | |
| After-tax weighted cost of capital | 9.67% |
| Capital structure: | |
| Common equity | 55% (Cost = 12%) |
| Debt | 45% (Cost = 11%) |
| Capital charge factor | 17.5% |

Figure 2. Comparison of TPC for the Two NGCC Cases

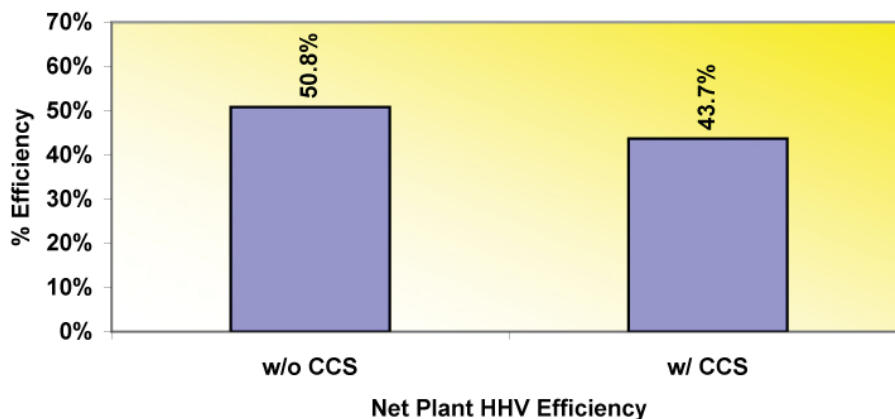


All costs are in January 2007 U.S. dollars.

Efficiency

The net plant HHV efficiencies for the two NGCC cases are compared in Figure 3. This analysis indicates that adding CCS to the NGCC reduces plant HHV efficiency by more than 7 percentage points, from 50.8 percent to 43.7 percent.

Figure 3. Comparison of Net Plant Efficiency for the Two NGCC Cases



Levelized Cost-of-Electricity

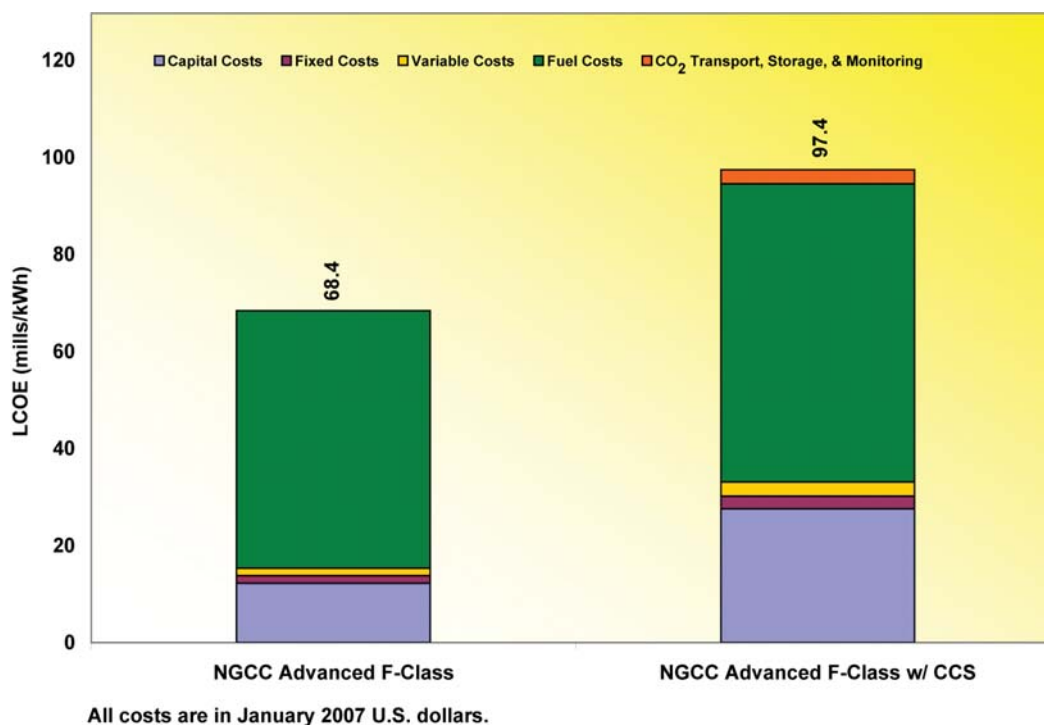
The LCOE is a measurement of the coal-to-busbar cost of power, and includes the TPC, fixed and variable operating costs, and fuel costs levelized over a 20-year period. The calculated cost of transport, storage, and monitoring for CO₂ is about \$7.00/short ton, which adds roughly 3 mills to the LCOE.

The NGCC without CCS plant generates power at an LCOE of 68.4 mills/kWh at a CF of 85 percent. When CCS is included, the increased TPC and reduced efficiency result in a higher LCOE of 97.4 mills/kWh.

Environmental Impacts

Listed in Table 4 is a comparative summary of emissions from the two NGCC cases. Mass emission rates and cumulative annual totals are given for sulfur dioxide (SO₂), NO_x, PM, Hg, and CO₂.

Figure 4. Comparison of Levelized Cost-of-Electricity for the Two NGCC Cases



The emissions from both NGCC plants evaluated meet or exceed Best Available Control Technologies requirements for the design NG specification and EPA 40 CFR Part 60, Subpart KKKK. The CO₂ is reduced by 90 percent in the capture case, resulting in less than 167,000 tons/year of CO₂ emissions. The cost of CO₂ avoided is defined as the difference in the 20-year LCOE between controlled and uncontrolled like cases, divided by the difference in CO₂ emissions in kg/MWh. In this analysis, the cost of CO₂ avoided is about \$83/ton. Sulfur dioxide, Hg, and PM emissions are negligible. Raw water usage in the CCS case is over 85 percent greater than for the case without CCS primarily because of the large Econamine process cooling water demand.

Table 4. Comparative Emissions for the Two NGCC Cases @ 85% Capacity Factor

| Plant Type | NGCC | |
|--|-------------|----------------|
| | Without CCS | With CCS (90%) |
| CO₂ | | |
| • tons/year | 1,661,720 | 166,172 |
| • lb/MMBtu | 119 | 11.9 |
| • cost of avoided CO ₂ (\$/ton) | N/A | 83 |
| SO₂ | | |
| • tons/year | N/A | N/A |
| • lb/10 ⁶ Btu | N/A | N/A |
| NO_x | | |
| • tons/year | 127 | 127 |
| • lb/MMBtu | 0.009 | 0.009 |
| PM (filterable) | | |
| • tons/year | N/A | N/A |
| • lb/MMBtu | N/A | N/A |
| Hg | | |
| • tons/year | N/A | N/A |
| • lb/TBtu | N/A | N/A |
| Raw water usage, gpm | 2,511 | 4,681 |

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Reference: Cost and Performance Baseline for Fossil Energy Plants, Vol. I, DOE/NETL-2007/1281, May 2007.

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GENERATION OF ELECTRIC POWER

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Assistant Professor
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| | |
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MAJOR PARAMETER DECISIONS

The major parameter decisions that must be made for any new electric power-generating plant or unit include the choices of energy source (fuel), type of generation system, unit and plant rating, and plant site. These decisions must be based upon a number of technical, economic, and environmental factors that are to a large extent interrelated (see [Table 8.1](#)). Evaluate the parameters for a new power-generating plant or unit.

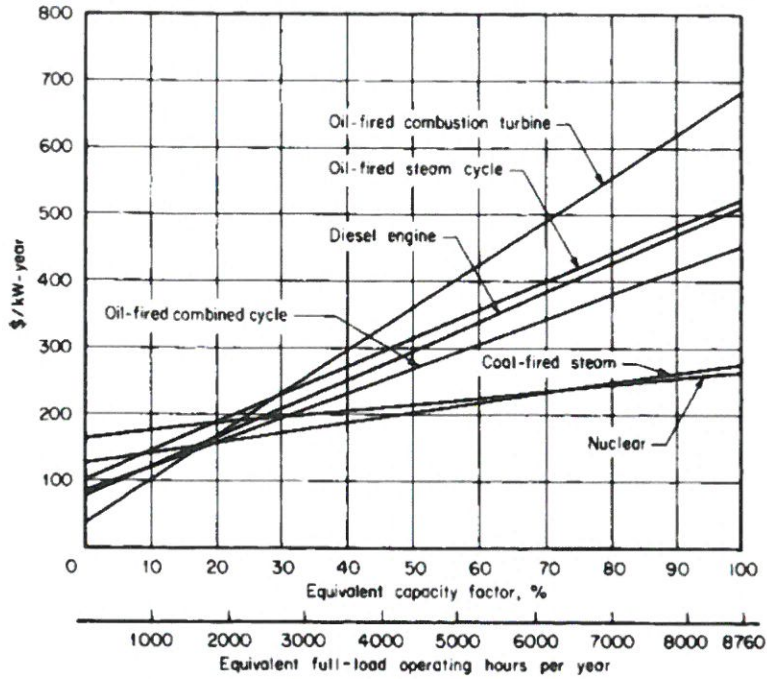


FIGURE 8.4 Screening curves for electric-generation-system alternatives based on assumption that natural gas is unavailable.

$$\frac{550,000 \text{ MWh}/100 \text{ MW}}{8760 \text{ h/yr}} \diamond 100 \text{ percent} \cdot 68.2 \text{ percent}$$

2. Compute Annual Capacity Factor in Hours per Year

The factor is $(68.2/100)(8760 \text{ h/yr}) = 5950 \text{ h/yr}$.

ANNUAL FIXED-CHARGE RATE

Estimate the annual fixed rate for an investor-owned electric utility.

Calculation Procedure

1. Examine the Appropriate Factors

As shown in Table 8.6, the annual fixed-charge rate represents the average, or "levelized," annual carrying charges including interest or return on the installed capital, depreciation or return of the capital, tax expense, and insurance expense associated with the installation of a particular generating unit for the particular utility or company involved.

TABLE 8.6 Typical Fixed-Charge Rate for Investor-Owned Electric Utility

| Charge | Rate, percent |
|--------------|---------------|
| Return | 7.7 |
| Depreciation | 1.4 |
| Taxes | 6.5 |
| Insurance | 0.4 |
| Total | 16.0 |

Related Calculations. Fixed-charge rates for investor-owned utilities generally range from 15 to 20 percent; fixed-charge rates for publicly owned utilities are generally about 5 percent lower.

FUEL COSTS

Calculate fuel costs on a dollars per megajoule (and million Btu) basis.

Calculation Procedure

1. Compute Cost of Coal

On a dollars per megajoule (dollars per million Btu) basis, the cost of coal at \$39.68/tonne (\$36/ton) with a heating value of 27.915 MJ/kg (12,000 Btu/lb) is $(\$39.68/\text{tonne})/[(1000 \text{ kg}/\text{tonne})(27.915 \text{ MJ}/\text{kg})] = \$0.001421/\text{MJ} = \$1.50/\text{million Btu}$.

2. Compute the Costs of Oil

On a dollars per megajoule basis, the cost of oil at \$28 per standard 42-gal barrel (\$0.17612/L) with a heating value of 43.733 MJ/kg (18,800 Btu/lb) and a specific gravity of 0.91 is $(\$0.17612/\text{L})/[(43.733 \text{ MJ}/\text{kg})(0.91 \text{ kg}/\text{L})] = \$0.004425/\text{MJ} = \$4.67/\text{million Btu}$.

3. Compute the Cost of Natural Gas

On a dollars per megajoule basis, natural gas at \$0.1201/m³ (\$3.40 per thousand standard cubic feet) with a heating value of 39.115 MJ/m³ = 1050 Btu/1000 ft³ costs $(\$0.1201/\text{m}^3)/(39.115 \text{ MJ}/\text{m}^3) = \$0.00307/\text{MJ} = \$3.24/\text{million Btu}$.

4. Compute Cost of Nuclear Fuel

On a dollars per megajoule basis, nuclear fuel at \$75.36/MWday costs $(\$75.36/\text{MWday})/[(1.0 \text{ J}/\text{MWs})(3600 \text{ s}/\text{h})(24 \text{ h}/\text{day})] = \$0.00087/\text{MJ} = \$0.92/\text{million Btu}$.

AVERAGE NET HEAT RATES

A unit requires 158,759 kg/h (350,000 lb/h) of coal with a heating value of 27.915 MJ/kg (12,000 Btu/lb) to produce 420,000 kW output from the generator. In addition, the unit has electric power loads of 20,000 kW from required power-plant auxiliaries, such as boiler feed pumps. Calculate the average net generation unit rate.



ENVIRONMENTAL LAW & POLICY CENTER

Protecting the Midwest's Environment and Natural Heritage

April 1, 2016

Submitted Via E-mail Only.

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Commission Staff:

The Environmental Law and Policy Center (“ELPC”) and 5 Lakes Energy hereby submit the following comments in response to the Public Utility Regulatory Policies Act of 1978, Pub. L. No. 95-617, 92 Stat 3117 (“PURPA”) Technical Advisory Committee Draft Report on the Continued Appropriateness of the Commission’s Implementation of PURPA prepared by Michigan Public Service Commission Staff (“Draft Report”).

I. Introduction

On October 27, 2015, the Michigan Public Service Commission (“Commission”) issued an Order commencing investigation into PURPA and the avoided cost payments that a public utility may be obligated to pay to a Qualifying Facility (“QF”). Case No. U-17973, Dkt. #1 (Mich. PSC 2015). In its Opening Order, the Commission noted that the passage of time and significant changes in the energy industry merited a comprehensive examination of PURPA and avoided cost issues. One of these changes is the increased availability of renewable energy.

By the Commission’s order, a Technical Advisory Committee (“TAC”) was established consisting of Staff, representatives of electric utilities and electric cooperatives, QFs, small power producers, and advocates. At the February 10, 2016 TAC meeting, Staff presented a Straw Man proposal that included preliminary avoided cost calculations for five different methodologies: Hydro, Biomass, Landfill Gas, Solar, and Wind. On February 24, 2016, ELPC and 5 Lakes Energy provided comments responsive to the Straw Man proposal. On March 15, 2016, Staff circulated the Draft Report to the TAC. ELPC and 5 Lakes Energy appreciate the opportunity to submit comments to the Draft Report.

The avoided cost for each technology must be fair and non-discriminatory, which requires an evaluation of the specific characteristics of the type of renewable generation. While ELPC and 5 Lakes Energy’s comments support a robust avoided cost methodology for all QFs, we provide specific analysis related to solar and cogeneration. ELPC and 5 Lakes Energy have previously participated in working groups established by the Commission addressing the

characteristics of solar generation and these comments are a natural extension of that work. Other participants in the TAC have focused on the specific attributes of other renewable technologies which should also be given full and careful consideration in establishing avoided cost rates.

II. Some Of The Methodologies Presented As Options In The Draft Report Do Not Reflect The Utility's Full Avoided Cost

In order to encourage the development of cogeneration and small power production facilities, Section 210 of PURPA requires large electric utilities to purchase available energy and capacity from small power producers, known as “qualifying facilities” or QFs. *See* 16 U.S.C. § 824a-3; *American Paper Inst. v. Am. Elec. Power Serv. Corp.*, 461 U.S. 402, 405 (1983) (“Section 210 of PURPA was designed to encourage the development of cogeneration and small power production facilities.”). The Federal Energy Regulatory Commission (“FERC”) has delegated to state commissions the responsibility to set rates for purchases from qualifying cogenerators and small power producers by electric utilities under their ratemaking authority. *State ex rel. Utilities Comm’n v. North Carolina Power*, 450 S.E.2d 896, 899 (1994); *see also Small Power Production and Cogeneration Facilities Regulations Implementing Section 210 of PURPA* (Order No. 69), 45 Fed. Reg. 12214, 12215 (Feb. 25, 1980). In doing so, FERC stated that it “believe[d] that providing an opportunity for experimentation by the States is more conducive to the development of these difficult rate principles.” *Id.* at 12231.

PURPA leaves the specific methodology to be used in determining avoided cost to the states’ discretion. *See California Public Utilities Comm’n Order Denying Rehearing*, 134 FERC 61,044, 61,160 (2011) (granting state commissions the authority to decide what particular capacity is being avoided in setting avoided cost rates). In Michigan, where the state legislature has not mandated the use of a particular avoided cost methodology, the appropriate methodology is left to the Commission.

PURPA requires that rates for the purchase of energy from QFs not discriminate against qualifying cogenerators or qualifying small power producers and be just and reasonable to the consumers of the electric utility and in the public interest. *See* 16 U.S.C. § 824a-3(b) (2005); 18 C.F.R. § 292.304(a)(1) (2015). Under FERC’s implementing regulations, upheld by the U.S. Supreme Court in 1983, avoided cost rates are set at the utility’s **full avoided cost**. *See American Paper Inst.*, 461 U.S. 402 (1983). Under these regulations, a utility’s full avoided cost is the incremental cost the utility would bear if it were required itself to supply or purchase the electricity produced by the small power producer. *See Public Service Co. v. Public Utilities Com.*, 687 P.2d 968, 973 (Colo. 1984); 18 C.F.R. § 292.304(b) and (e).

The Draft Report properly takes into account both energy and capacity impacts on avoided costs on a technology-specific basis. ELPC and 5 Lakes Energy support the Draft Report’s technology-specific methodology and note that a 2010 FERC ruling confirmed that avoided cost rates can differentiate among QFs using various technologies on the basis of the supply characteristics of the different technologies. *See* “Order Granting Clarification and Dismissing Rehearing,” 133 FERC ¶ 61,059 (2010). Avoided cost methodology should differ by technology, because each of the available technologies has different attributes that impact avoided cost in different ways. However, the methodology must be non-discriminatory and result in a full and fair avoided cost rate for each of the different methodologies.

a. Capacity Component of Avoided Cost

We are generally supportive of the Staff’s approach to calculating the value of capacity based on the Cost of New Entry using a combustion turbine capacity resource. We note, however, that the Staff calculation uses a capital charge rate that appears low and also likely fails to include avoided income taxes. Income to a QF is taxable to the QF owner and not to the utility, so avoided income taxes must be accounted for. We urge staff to revisit the charge rate calculation and include the details of its determination in the report.

In 18 C.F.R. 292.304(e), FERC explicitly sets out those factors that *must*, to the extent practicable, be taken into account when determining avoided costs. Amongst the factors that *must be considered* are:

(2) The availability of capacity or energy from a qualifying facility during the system daily and seasonal peak periods, including:

(vii) The smaller capacity increments and the shorter lead times available with additions of capacity from qualifying facilities.

18 C.F.R. 292.304(e). Therefore, the Commission must evaluate the Capacity Component options in the Staff Report in light of this factor. Staff’s Capacity Component Option 1 reflects the conventional calculation of Cost of New Entry of the least-costly form of pure capacity. In economic theory, this should be the market clearing price for capacity for a utility or market in which generation is dependent on market revenue to recover costs and new capacity is added as needed on an annual basis. In practice, because of the availability of cost recovery through cost-of-service regulation and the lumpiness of power plant capacity and construction, capacity is added in larger increments every few years. Consequently, a utility is positioned to claim that it has no need for additional capacity except on those rare occasions when it claims that it needs to build a large plant. Staff’s Capacity Component Options 2 and 3 and Consumers Energy’s comments on capacity value as reported in the Staff report reflect this phenomenon.

Capacity added in smaller increments, therefore, avoids the cost of the utility carrying unnecessary and unused capacity for several years until demand catches up to the constructed capacity. As a result, the avoided capacity cost of smaller capacity additions coincident with requirements is always larger per unit capacity than Cost of New Entry as calculated by staff. We acknowledge that the timing with which QFs come on line may not be coincident with the necessity for new capacity; this will be particularly so because it is not in a utility’s self-interest to announce its needs and invite others to displace its own additions to rate base. We therefore strongly recommend that the Commission adopt the Staff recommendation that QFs with capacity less than 5 MW be compensated for capacity based on the full Cost of New Entry calculated by the method proposed by Staff. We also recommend the Commission be cautious about producing a discriminatory effect on QFs as compared to utility generation if it considers Options 2 or 3.

b. Effective Load Carrying Capacity

We appreciate and support Staff’s proposal to base capacity value on effective load-carrying capacity (“ELCC”). This is the appropriate way to determine the effect on firm capacity requirements of resource-limited QFs such as solar, hydropower, and cogeneration. However, we

urge Staff to recognize that effective load-carrying capacity is potentially facility-specific and technology-dependent. A fixed solar array facing south, a fixed solar array facing southwest, a single-axis tracking solar array, and a dual-axis tracking array will each have a different ELCC. A cogeneration facility that operates whenever the host facility needs process heat will likely have an ELCC that is nameplate capacity less its forced outage rate, which according to Oak Ridge National Laboratory, can be as low as 2.5%, while a dispatchable cogeneration facility may also fail to produce due to low spark spread. Thus, while we support use of technology-average ELCC as a starting point in the Commission's methodology, we also urge room for case-specific determination.

With specific respect to solar QFs, we note that the ELCC calculation methods commonly used by utilities and regional transmission organizations ("RTOs") fail to account for the fact that solar generation is specifically correlated with peak loads because solar heat gain during times of high insolation causes a part of peak loads. Typical averaging methods miss this phenomenon. While we do not expect the Commission to overcome this deficiency and use capacity credits that would not be accepted by RTOs, the Commission should understand that it will be undervaluing solar capacity by using these methods.

We further note that if a QF is required to purchase stand-by capacity against the potential that the QF will not be generating at all times, then the QF is effectively providing 100% capacity through the bundle of QF operations and standby power agreements and should therefore be credited for capacity accordingly.

c. Energy Component of Avoided Cost

Neither PURPA nor its implementing regulations support the interpretation of avoided cost as the price of energy on the spot market or the short-term marginal cost to the utility of generating one additional unit of electric energy. Instead, PURPA encourages states to look beyond the cost of "alternative sources which are instantaneously available to the utility" and evaluate factors such as the reliability of the power and cost savings that could accrue to the utility in the future. *See Public Service Co.*, 687 P.2d at 973 (citing H.R. Conf. Rep. No. 95-1750, 95th Cong., 2d Sess., reprinted in 1978 U.S.C.C.A.N. 7797, 7832-33). In order to be just and reasonable, the avoided cost rate does not need to be set at the lowest possible rate available. *See American Paper Inst.*, 461 U.S. at 413-14.

We support Staff's recommendation to allow the QF to choose amongst the Energy Component options laid out in the draft report. In particular, we note that when capacity value is based on the costs of a combustion turbine, the remaining avoided capital costs of the combined cycle proxy plant must of necessity be accounted for through the energy component of the avoided cost protocol. We wish to stress that we concur with staff that this is the correct way to determine the value of capacity and energy. Option 3 does this explicitly through the calculated adder to operating costs of the proxy plant. Options 1 and 2 provide the possibility that locational marginal price will periodically exceed marginal operating costs of the QF; in theory this would be the case in a wholesale market in which generators are wholly dependent on wholesale market revenue to recover costs. Since the Midcontinent Independent System Operator ("MISO") market, in particular, is dominated by generators who receive extra-market revenue through cost-of-service regulation that incents excess capacity and suppresses energy market clearing prices, it is important to provide Option 3 to QFs. We, therefore, caution the

Commission that it should not permit utilities to erect delays or other transaction costs to induce a QF to choose Options 1 or 2.

III. The Draft Report's Recommended Methodology Should Be Expanded To Calculate The Utility's Full Avoided Cost, Taking Into Account Technology-Specific Values

The Draft Report identifies several factors that Staff suggests *may be* considered in determining avoided cost, citing to 18 C.F.R. 292.304(e). Draft Report at 13. We disagree with Staff's characterization of these factors as within the Commission's discretion to consider. To the contrary, FERC's regulations require the Commission to consider these factors, to the extent they can practicably be considered. As described in more detail below, each of the factors identified by ELPC and 5 Lakes Energy can practicably be considered in setting avoided cost.

In 18 C.F.R. 292.304(e), FERC explicitly sets out those factors that *must*, to the extent practicable, be taken into account when determining avoided costs. These factors should be evaluated in light of the underlying purpose of PURPA. As the Court explained in *FERC v. Mississippi*, "Congress believed that increased use of these sources of energy would reduce the demand for traditional fossil fuels," and it recognized that electric utilities had traditionally been "reluctant to purchase power from, and to sell power to, the nontraditional facilities." 456 U.S. 742, 750 (1982) (footnote omitted). The factors that *must be considered* are:

- (1) [Utility system cost] data provided pursuant to § 292.302(b), (c), or (d), including State review of any such data;
- (2) The availability of capacity or energy from a qualifying facility during the system daily and seasonal peak periods, including:
 - (i) The ability of the utility to dispatch the qualifying facility;
 - (ii) The expected or demonstrated reliability of the qualifying facility;
 - (iii) The terms of any contract or other legally enforceable obligation, including the duration of the obligation, termination notice requirement and sanctions for non-compliance;
 - (iv) The extent to which scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the utility's facilities;
 - (v) The usefulness of energy and capacity supplied from a qualifying facility during system emergencies, including its ability to separate its load from its generation;
 - (vi) The individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system; and
 - (vii) The smaller capacity increments and the shorter lead times available with additions of capacity from qualifying facilities; and

(3) The relationship of the availability of energy or capacity from the qualifying facility as derived in paragraph (e)(2) of this section, to the ability of the electric utility to avoid costs, including the deferral of capacity additions and the reduction of fossil fuel use; and

(4) The costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a qualifying facility, if the purchasing electric utility generated an equivalent amount of energy itself or purchased an equivalent amount of electric energy or capacity.

18 C.F.R. § 292.304(e)(1)-(4).

The Draft Report specifically recommends that transmission costs and line loss mitigation not be included in the avoided cost calculation at this time. The Draft Report does not argue that it would not be practicable to include these calculations, but instead, indicates that these attributes should not be included out of consideration for the relationship formed between the QF and the utility. As described more fully below, it is practicable and more accurate to consider transmission costs and line loss mitigation and therefore the Commission is obligated to do so.

a. The Commission Must Consider Avoided Transmission Costs

With respect to all generation technologies, the Commission must include appropriate treatment of avoided transmission costs in its methodology. Michigan regulated electric utilities do not directly own or operate transmission facilities, but purchase transmission services through either the MISO or PJM pursuant to tariffs adopted by those organizations and approved by FERC. Most costs of transmission are broadly “socialized” within the footprints of these RTOs and are allocated to individual utilities based on the twelve monthly peak hours of power delivery to step-down substations in each utility’s service territory. Thus, any QF that is interconnected at sub-transmission voltage and whose power output partially or fully reduces power delivery from the transmission system to such a substation during monthly peak hours directly reduces transmission charges to its utility. This reduction constitutes an avoided cost to the utility that the Commission must determine and consider as an avoided cost. The amount of such avoided cost will necessarily be based on the specific circumstances of the QF but the method of determination can be addressed now by the Commission.

In addition to this basic allocation of transmission costs to utilities, at certain times (not necessarily at monthly peak hours) transmission congestion charges are allocated to a utility when power cannot be delivered to a substation from the least-cost generation resource due to constraints in the transmission system. Specific substations may experience congestion charges at high frequency or in high amounts. These congestion charges are intended to provide a market signal as to the need for additional transmission capacity or alternative resources such as load reduction or distributed generation. A QF that is interconnected through such a substation will reduce such congestion charges, and the Commission must determine either that any avoided congestion charges are an avoided cost to the utility or that any deferred or avoided capacity investments are an avoided cost to the utility. In certain circumstances where transmission congestion, substation capacity, or line length and load prevent the utility from delivering adequate voltage to customers on the same distribution circuits as the QF, the avoided

transmission cost may take the form of improved service to those other customers and this should be accounted for as an avoided cost. The amount of such avoided cost will necessarily be based on the specific circumstances of the QF, but the method of determination can be addressed now by the Commission.

b. The Commission Must Consider Line Loss Mitigation

To the extent that any QF interconnected at sub-transmission voltage serves local load and does not place that power on the transmission system, it avoids line and transformer losses. Thus, the value of energy and capacity provided by the QF should each be scaled by the appropriate line-loss factor. The Commission routinely considers and adopts line-loss factors in general rate cases and applies those line-loss factors in power supply cost recovery cases. At minimum, the Commission should use the most recent line loss study of the relevant utility and make the appropriate adjustments to both energy and capacity avoided costs. It is important to note that the line-loss factors for energy and capacity are distinct and separately determined. We further note that while it is Commission practice to use annual average line-loss factors in adjusting energy costs, actual physical losses are the sum of some losses in transformers and similar equipment that are constant with respect to current and a substantial majority of actual physical losses that are proportional to the square of current. Consequently, any marginal reduction of load due to distributed generation reduces losses equal to nearly twice the proportional reduction in load. Thus, if the Commission only applies the line-loss factors determined in its rate cases, it will systematically understate the avoided costs of distributed generation.

c. The Commission Should Also Consider Hedging Value

Solar and other distributed generation provided through long-term QF contracts at a fixed price or a price schedule also acts as a hedging mechanism, reducing a utility's fuel price uncertainty. This hedge has real value and should be included in avoided costs. The standard method to value such a hedge is to determine the levelized cost of the contracted power to the utility using a zero-risk discount rate, for which US treasury inflation-protected securities are normally the proxy. If the contract is indexed to a macroeconomic measure such as general inflation, then the discount rate used in the levelized cost calculation should be adjusted for the index; for example, if the contract is indexed to inflation then the discount rate should be based on (non-inflation-protected) U.S. treasury securities.

d. The Commission Should Also Consider Avoided Emissions and Environmental Compliance Costs

Utilities should also include avoided carbon costs and other emissions allowances in the calculation of avoided energy costs. While environmental considerations are not included in FERC's regulations, planning numbers associated with regulation of greenhouse gas emissions reflect imminently real costs that are not zero. While there are challenges to quantifying this benefit, the value should not be set at zero. Unless such costs are quantified and included in the avoided costs on which a QF's contract is based, then the value of any such future avoided costs to the utility should accrue to the QF at such time as regulatory changes cause such costs to be manifest. Some care is needed on this point, as some environmental benefits, such as renewable energy credits, can accrue to the QF in the ordinary course of regulation; but others, such as

avoidance of emissions allowances by utility generation, may accrue to the utility in the ordinary course of regulation.

e. The Commission Should Consider a Value of Solar Analysis to Help Establish Avoided Costs for Distributed Solar Resources in Michigan

States and utilities are undertaking increasingly sophisticated evaluations of the true avoided cost of solar. These evaluations not only acknowledge the factors FERC requires be considered in determining avoided costs, but also demonstrate the feasibility of incorporating these factors into an avoided cost methodology that captures the full, technology-specific avoided costs of solar PV. Staff's 2014 Solar Working Group report discussed several programs that have attempted to establish a fair value of solar ("VOS") rate based on avoided utility costs, including the Austin Energy VOS Program, the Minnesota VOS methodology, a dynamic pricing program proposed by 5 Lakes Energy, and a Michigan-specific white paper developed by the National Renewable Energy Lab ("NREL").¹ The Solar Energy Industries Association ("SEIA") maintains a webpage with links to more than thirty other recent solar cost-benefit studies.²

Although the details vary, the benefits and costs studied in VOS analysis generally fall into the following categories: energy (including line losses), capacity (both generation capacity and transmission and distribution capacity), grid support services (also referred to as ancillary services), financial risk (fuel price hedging and market price response), security risk (reliability and resilience), environmental benefits (carbon emissions, criteria air pollutants, and others) and social benefits. Many of these values relate to solar generation's innate characteristics – its natural coincidence with peak demand; its ability to avoid transmission capacity costs and line losses by siting smaller systems on the distribution grid closer to load; its scalability; its lack of fuel volatility; and other characteristics.

The growing body of VOS analysis consistently demonstrates that solar energy has value that significantly exceeds more narrowly calculated avoided costs. While not every factor can be quantified precisely, a VOS analysis generally provides a more accurate estimate of the "full avoided costs" associated with solar generation over the life of the solar generation system. Thus, several states and utilities have established or are considering the use of a VOS analysis to establish a technology-specific avoided cost under PURPA that explicitly accounts for the unique values of distributed solar PV.³

The firm Clean Power Research ("CPR") has conducted a number of comprehensive market-based VOS studies that have been used by a number of states and utilities to help inform program and tariff design. CPR has just completed a new report that describes a proposed methodology and other recommendations for valuing distributed solar energy resources in

¹ See Michigan Public Service Commission, *Solar Working Group – Staff Report* (June 30, 2014) (available at <http://efile.mpsc.state.mi.us/efile/docs/17302/0106.pdf>). The MPSC's Solar Working Group website also includes links to other value of solar (VOS) resources and documents. The website is available at the following link: http://www.michigan.gov/mpsc/0,4639,7-159-16393_55246_55249-321593--,00.html.

² See <http://www.seia.org/policy/distributed-solar/solar-cost-benefit-studies>.

³ For example, Georgia Power recently filed a new VOS framework that it intends to "serve as the basis for new avoided cost calculations, renewable program development, project evaluation, and rate design." See Docket 40161, Georgia Power Company's 2016 Integrated Resource Plan at 10-103.

Michigan.⁴ The report concludes that a properly-designed VOS analysis could be used to establish a technology-specific avoided cost for distributed PV resources in Michigan. The Commission should carefully consider this report as well as the other VOS analyses performed for other states and utilities in order to develop a technology-specific rate that fairly reflects the “full avoided costs” associated with solar generation.

IV. The Commission Should Adopt Staff’s Recommendation Of A Standard Offer For QFs That Are 5 MW And Smaller

In the Draft Report Staff states that it “supports a standard rate for QFs that are 5 MW and smaller which includes the full avoided cost capacity rate.” ELPC and 5 Lakes Energy also support a standard rate for QFs 5 MW and smaller. In addition to creating an avoided cost methodology that encourages cogeneration and small power production facilities, the Commission must also evaluate the framework under which energy and capacity are provided by QFs. This framework must include the availability of standard rates to QFs that reduce transaction costs and are of sufficient length to provide certainty regarding financing. Long-term contracts enable investors to calculate return on investment with certainty and instill confidence that the borrower will be in a position to repay any loan extended. With increased price certainty for a project, investors typically require a lower return, which, in turn, reduces the cost of financing. Unlike the electric utilities to which they provide energy and capacity, a QF is not guaranteed a rate of return on its activities. Without some continuity and certainty, QFs are placed in a position of considerable risk in proceeding forward in a cogeneration or small power production enterprise.

The establishment of standard rates under PURPA provides the certainty necessary to encourage development of cogeneration and small power production facilities. PURPA regulations *require* electric utilities to establish standard rates for purchases from QFs with capacity of 100 kilowatts (“kW”) or less, and give state commissions the authority to develop standard rates for larger QFs. 18 C.F.R. §§ 292.304(c)(1), (2). In contrast to an individualized rate, a standard rate is the avoided cost rate that would apply to any QF eligible for that rate that provides energy or capacity to the utility. The availability of a standard rate reduces transaction costs for individual QFs, avoiding the cost and burden of establishing an individualized avoided cost rate and reducing barriers to entry. Although standard rates do not differentiate among individual QFs, they can be technology specific and “differentiate among qualifying facilities using various technologies on the basis of the supply characteristics of the different technologies.” *Id.* at 292.304(c)(3)(ii).

In promulgating regulations, FERC agreed with comments stressing the need for certainty with regard to return on investment in new technologies. 45 Fed. Reg. at 12224. Standard rates are essential for small QFs to obtain financing. FERC acknowledged that “in order to be able to evaluate the financial feasibility of a cogeneration or small power production facility, an investor needs to be able to estimate, with reasonable certainty, the expected return on a potential investment before construction of a facility.” *Id.* at 12218.

⁴ Clean Power Research, *PV Valuation Methodology, Recommendations for Regulated Utilities in Michigan* (February 2016) (attached as Exhibit 1) available at <http://www.growsolar.org/wp-content/uploads/2016/03/PV-Valuation-in-Michigan.pdf>.

ELPC and 5 Lakes Energy agree with the Draft Report's support for a standard rate for QFs with generating capacity 5 MW and less because it will further the purposes of PURPA by promoting growth of cogeneration and small power production facilities. In fact, the FERC gave states the discretion to establish standard rates for larger QFs *precisely because* standard rates significantly encourage cogeneration and small power production. 45 Fed. Reg. at 12223. Other states have recognized the benefit of extending the standard rate to larger QFs. In upholding the propriety of continuing to offer standard rate contracts to QF's under 5MW, the North Carolina Utilities Commission considered Public Staff testimony that:

. . . setting the standard threshold at a [5 MW] level that allows QFs to receive the benefit of reduced transaction costs and appropriate economies of scale provides ratepayers with the assurance that the utilities' resource needs are being met by the lowest cost options that may be available.

Order Setting Avoided Cost Input Parameters, Docket No. E-100, SUB 140, North Carolina Utilities Commission, (Dec. 31, 2014). Extending standard rates for larger QFs in Michigan will not only serve the purposes of encouraging the growth of cogeneration and small power production facilities, it will benefit ratepayers by providing them with the lowest cost option to meet resource needs.

The Draft Report does not address the required term of a standard offer. The Commission should offer standard rates with conditions that are conducive to growth of cogeneration and small power production. Specifically, the Commission should require utilities to offer long-term levelized capacity payments and energy payments for a variety of terms, including terms long enough to provide a QF with sufficient certainty to obtain financing for and undertake capital expenditures.

V. Administrative Process

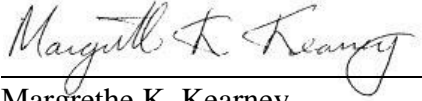
ELPC and 5 Lakes Energy agree with Staff's recommendation that the overall avoided cost methodology can be accomplished through an initial process that focuses on methodology. *See* Draft Report at 7. Although we agree that the process will likely be a one-time event, we suggest that the Commission provide more clarity around what would constitute a compelling reason for revising the avoided cost calculation methodology. We support Staff's attempt to limit the number of separate proceedings in which QFs will be required to participate, and encourage efforts to reduce the burden of QF participation. We also support the biennial update of avoided cost data and suggest that this update be made part of other biennial utility proceedings, such as biennial Renewable Energy Standards dockets.

VI. Conclusion

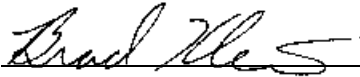
The Draft Report provides a solid basis for developing an updated avoided cost methodology in Michigan, but must be expanded to account for the utility's full avoided cost. The methodology must take into account transmission costs and avoided line losses, and should include an evaluation of hedging value and avoided emissions. ELPC and 5 Lakes Energy support the availability of standard rates to QFs with a generating capacity of up to 5 MW through contracts with terms of sufficient length to enable financing and capital expenditures. Michigan should join the other states and utilities undertaking these comprehensive analyses to

develop technology-specific avoided costs, the result of which will be a more robust avoided cost methodology that furthers the goals of PURPA.

Respectfully submitted,



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PV Valuation Methodology

Recommendations for Regulated Utilities in Michigan



February 23, 2016

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CPR's Solar Valuation Background

CPR holds a unique position in the solar valuation field, having developed the first value of solar tariff offered in North America. Austin Energy approved CPR's value-based pricing presented in a 2011 study, and offered it as a new form of compensation to its solar customers. CPR had performed an earlier valuation study for Austin Energy in 2006.

In 2014, CPR worked with utilities and stakeholders in Minnesota to develop the first detailed, public methodology to be used by utilities in setting rates. This methodology, guided by state legislative requirements, was approved by the Minnesota Public Utilities Commission for utilities seeking a value-based compensation tied to the costs and benefits of distributed solar generation. It is the only such Commission-approved methodology in North America.

In April 2015, CPR published a comprehensive market-based value of solar study that was commissioned by the Maine Public Utilities Commission. This study was also a stakeholder-driven process, and included a wide set of scenarios and assumptions for the purpose of informing public policy. It included three detailed studies for three utility regions.

CPR has performed a number of related studies, including net metering cost/benefit studies and solar fleet shape modeling for Duke Energy, We Energies, Portland General Electric, USD/San Diego Gas and Electric, Solar San Antonio, and NYSERDA/ConEdison. CPR has also worked with solar industry organizations, such as the Solar Electric Power Association (SEPA) and the Solar Energy Industries Association (SEIA) to evaluate other value-based compensation schemes, such as annual versus levelized VOS, long-term inflation-adjusted VOS, value of export energy, and others.

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PART 1 - INTRODUCTION

Introduction

Clean Power Research (CPR) was engaged by the Midwest Renewable Energy Association to develop a methodology for valuing distributed solar energy resources. Many studies have been performed by CPR and others over recent years to in which methodologies have been developed to perform these valuations.

Distributed solar differs from conventional generation in several respects. First, it is not dispatchable and therefore requires a means for evaluating its “effective” capacity to put it on a comparable economic footing with in-market resources.

Second, it is distributed, meaning that it avoids the losses associated with long-distance transmission, voltage step down at distribution substations, and the distribution lines. This requires that a loss savings factor be incorporated into the study.

Third, its production profile varies considerably, depending upon the orientation (azimuth and tilt angle) of the system and its location. As a practical approach, the concept of an aggregate “fleet” of resources is introduced to address this, and the valuation is designed to value output of the fleet.

Finally, solar provides a number of societal benefits, such as the ability to produce energy without harmful air emissions and protection against uncertainty in fuel price fluctuations. These benefits are “out of market” in the sense that the societal costs of conventional generation are not included in conventional ratemaking. It is left to the user of the methodology as to whether such benefits should be included in a valuation study.

Purpose

This report describes in general terms a methodology that may be used for such a valuation. For readability, the report is devoid of detailed equations and tables, and it does not include an actual valuation example based on this methodology. However, it does incorporate the lessons learned in a number of such valuation studies performed by CPR over the years.

In addition to the methodology, the report describes some options for implementation. These include the use of the methodology in evaluating existing net energy metering cross-subsidies,

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considerations for community shared solar, the adaptation of methods for energy exports and other DER technologies, and the use of results in value-based compensation schemes.

It is hoped that such a valuation exercise could be conducted using the methods described here.

Overview of Methodology

The methodology is described in three major parts. The first is a technical analysis where many of the key intermediate technical metrics are calculated. This include the definition of the study period, the rating conventions, the development of hourly fleet production profiles, the determination of “effective” capacity in relation to resource adequacy and the distribution system, and the treatment of loss savings.

The second part is the economic analysis of in-market benefits. This methodology includes avoided energy costs, avoided resource adequacy costs, avoided transmission capacity costs, and avoided distribution costs. It is important to note that this methodology incorporates some benefits that have been broken out as separate categories on other studies. For example, the energy benefit includes the economic impacts of both a change in load and a change in price. The resource adequacy benefit includes the contribution toward meeting both peak load and the planning margin.

Next, two out-of-market benefits are included. These are the benefits most commonly included in studies of this sort, and they include the avoided environmental cost and the fuel price guarantee. These benefits are more speculative and do not represent benefits for which a monetized transaction currently takes place in the energy marketplace.

PART 2 – TECHNICAL ANALYSIS

The Marginal PV Resource

The methodology incorporates in its framework the concept of a “Marginal PV Resource” for which the value of production is sought. Existing solar resources are not included in the analysis except to the extent that they shape the existing loads used in the analysis. It is understood that as the amount of solar in a system increases, the technical contribution towards capacity decreases. This is because the peak load shifts to non-daytime hours. Due to this effect, the initial solar resources (the “early adopters”) provide more technical benefits than systems

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installed in later years (the actual value depends on other factors such as fuel prices and these may increase or decrease).

With this in mind, it is necessary to state up front which of the solar resources are being evaluated: all resources to date? All resources anticipated over the next 20 years? This methodology is based on a marginal analysis of the next PV resource of unit size to come on line.

As described below, a PV Fleet Production Profile is developed that takes into account the diversity of locations and design attributes of the distributed solar fleet. The unit output of this fleet is, in effect, the Marginal PV Resource, even though such a resource does not exist in practice. The concept is helpful because it eliminates a set of complicating value scenarios (What is the value of a west-facing system? a tracking system? a system in the southern or northern part of the service territory?) The Marginal PV Resource therefore is the next installed increment of solar capacity that represents the geographical and design diversity of the distributed PV fleet.

Load Analysis Period and Economic Study Period

There are two separate periods of interest in performing the valuation: the Load Analysis Period and the Economic Study Period. The Load Analysis Period is used to evaluate technical parameters, such as the ability of the resource to deliver energy during peak times. Such analyses require the use of historical, measured data. For example, an evaluation of effective capacity may compare a year of hourly solar production against the same year of utility load. In this case, the Load Analysis Period would be defined as the year over which this technical analysis was based. The analysis could take place over several years (e.g., three years) in order to account for year-to-year load and weather variation.

The second period of interest is the Economic Study Period. This is the period over which the two economic alternatives are evaluated: the production of energy by the Marginal Resource and the delivery of energy using conventional generation. The costs and benefits of these alternatives occur in the future, so the Economic Study Period is selected over one or more future years.

The selection of Economic Study Period is often tied to the final metrics for presenting the benefits and costs, and the assumed useful service life of the resource (e.g., the 20 to 30 year life of solar PV) may be used. For example, if a 25 year service life is assumed, the study objective may be to estimate the levelized value over 25 years. Such an analysis would take into

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account anticipated capacity additions over this period, expected changes in wholesale energy costs, and load growth rates.

A valuation study may be designed to calculate a one-year, or first-year, value of generation. This is in contrast to a long-term levelized rate. Such an approach offers the advantage of accuracy because it is less dependent on long term forecasts (e.g., it would require a one-year fuel price forecast rather than a 25-year fuel price forecast). In this case, the investor in renewables takes the risk of future fluctuations in value. Rather than “locking in” a 25-year rate, the rate fluctuations year to year are unknown, and this may be an important factor in the investment decisions.

In the one-year analysis approach, long term benefits that fall outside of the analysis period, such as the avoidance of future generation capacity additions, may still be included. For example, a future year capacity addition could be included by amortizing the capacity cost of the addition over its expected life, calculating the present value of the annualized avoided costs that occur during the life of the Marginal Resource, and then amortizing this value over the life of the Marginal Resource. This results in the annual value attributed to the present resource in avoiding or deferring the need for future resources.

PV System Rating Convention

The methodology requires the establishment of a rating convention to be used for the Marginal Resource. There are several rating methods available, such as DC power under “Standard Test Conditions,” DC power under “PVUSA Test Conditions” (DC-PTC), and an AC rating that includes the effect of inverter efficiency.

The selection of rating convention is somewhat arbitrary, but must be used consistently. For example, if a DC rating is used, then the Marginal Resource would have a unit rating of 1 kW DC. When determining the annual energy produced, the same convention would be used: annual energy would be expressed as AC energy delivered to the grid per kW DC. Likewise, the effective generation capacity would be expressed as the effective generation capacity per kW DC.

Load Data and PV Fleet Production Profile

The capacity-related technical metrics that follow (see sections on Effective Load Carrying Capability and Peak Load Reduction below) are heavily dependent upon the assumed production profile of the Marginal PV Resource. If there is a good match between solar production and load, then the effective capacity is high. On the other hand, if the peak load

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occurs during times when solar production is poor, then the effective capacity will be low. This directly affects the economic capacity value.

Before calculating the match, it is necessary to obtain the load data and develop a solar production profile. Both the load and production profile are time series with start and end times corresponding to the Load Analysis Period described above. An hourly interval is most common for studies of this type, although other intervals could be used. MISO pricing is available in hourly intervals, and this will form the basis of the energy valuation. Therefore, hourly intervals are assumed here.

Two sets of load data are required: the MISO system load data and the utility distribution load data. The system load data will be used to calculate effective generation capacity, so the load data should correspond to the MISO zone associated with the utility. The distribution load data will be used to calculate the effective distribution capacity.

In addition, a production profile representing the output of the Marginal Resource is required over the Load Analysis Period. This can be either simulated or measured from sample PV resources, but must accomplish the following:

- The data must accurately reflect the diversity of geographical locations across the utility and the diversity of design orientations (range of azimuth angles and tilt angles, etc.). Typically, this requires the aggregation of several hundred systems comprising a representative “fleet” of solar resources.
- The data must not represent “typical year” conditions, but rather must be taken from the same hours and years as the load data. It must be therefore “time synchronized” with load.
- The gross energy output of the resource is required, not the net export energy which includes on-site consumption.

The fleet comprises a large set of real or anticipated PV systems having varying orientations (different tilt angles and azimuth angles) at a large number of locations. The intention is to calculate costs and benefits for the PV fleet as a whole, rather than for a specific system with specific attributes.

Effective Load Carrying Capability (ELCC)

Distributed solar is not dispatchable in the market, but it does have an indirect effect on the amount of power that is dispatched. If distributed solar produces energy during peak load

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hours, then the required amount of dispatchable capacity is lowered. Therefore, it is important to quantify how effective distributed solar is in reducing capacity requirements.

Effective Load Carrying Capability (ELCC) is the metric used for this purpose. It is typically expressed as a percentage of rated capacity. For example, if solar is credited with an ELCC of 50%, then a 100 kW solar resource is considered to provide the same effective capacity as a 50 kW dispatchable resource.

MISO is working to develop a process¹ for solar accreditation and several alternatives used at other ISOs are under consideration. When such a process becomes defined, it could be used to calculate ELCC using the PV Fleet Production Profile.

Before the process is developed, it will be necessary to select an interim method, and one such method is described here. This method has been used in other studies by CPR² and can be used as an easily implemented method until the MISO process is available.

Under the MISO tariff, Load Serving Entities (LSEs) are required to meet both a local clearing requirement (LCR) in their local resource zone (LRZ) as well as MISO-level planning reserve margin requirement (PRMR). Both of these requirements ensure that reliability meets a 1 day in 10 year loss of load standard. Each of the two requirements is considered separately.

First, the contribution of distributed solar in meeting the LCR requirement is dependent upon the load match of solar production with the zonal load. This could be evaluated as the average of the PV Fleet Production Profile during the peak 100 hours per year in the LRZ. The contribution of these distributed resources not only reduce the required resources to meet the peak zonal load but also reserve requirements. For example, if the average production during the peak 100 hours in the LRZ was 0.5 kWh per hour per kW of rated solar capacity and if the local resource requirement per unit of peak demand was 1.1, then the effective contribution of solar would be $0.5 \times 1.1 = 55\%$ of rated capacity.

Second, the contribution of distributed solar in meeting the PRMR requirement is dependent upon the load match with the MISO system load. In this case, the contribution could be calculated by averaging the PV Fleet Production Profile during the peak 100 hours per year in the MISO footprint and applying the planning reserve margin. For example, if the load match

¹ See "MISO Solar Capacity Credit" at:

<https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/SAWG/2015/20150806/20150806%20SAWG%20Item%2007%20Solar%20Capacity%20Credit.pdf>

² E.g., a 2014 valuation study for the Maine PUC.

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was 40% and the margin was 7%, then the effective contribution of solar would be $0.4 \times 1.07 = 43\%$ of rated capacity.

Finally, the LSEs may use the same resource to serve both the LCR requirement and the PRMR requirement. The effective capacity, or ELCC, would be selected as the lower of the two results. Continuing the example, if the effective solar capacity was 55% for LCR but only 43% for PRMR purposes, then the overall ELCC would be 43%.

Peak Load Reduction (PLR)

The ELCC is a measure of effective capacity for resource adequacy. It is an essential input to evaluating the benefit of avoided generation capacity costs. However, it is not necessarily a good metric for evaluating avoided transmission and distribution (T&D) capacity benefits for two reasons: (1) it is based on the loads of the MISO zone, rather than the utility's distribution loads (peaks make occur at different times); and (2) it averages output over many hours, whereas distribution planning requires that the resource be there for a small number of peak hours.

Therefore, a different measure of effective capacity can be used in evaluating the distribution benefits. The Peak Load Reduction (PLR) is defined as the maximum distribution load over the Load Analysis Period (without the Marginal PV Resource) minus the maximum distribution load over the Load Analysis Period (with the Marginal PV Resource).

The distribution load is the power entering the distribution system from the transmission system (i.e., generation load minus transmission losses). In calculating the PLR, it is not sufficient to limit modeling to the peak hour. All hours over the Load Analysis Period must be included in the calculation. This is because the reduced peak load may not occur in the same hour as the original peak load.

Loss Savings Analysis

Distributed solar resources not only displace energy delivered to the load. They also avoid losses in the transmission and distribution lines. To account for this, Loss Savings Factors are calculated and incorporated into the analysis.

Loss Savings Factors depend on the benefit and cost category under evaluation. For example, one Loss Savings Factor could be determined for the avoided energy costs by determining the losses that would be incurred in the absence of PV the solar hours of a given year, and comparing this to the losses that would be incurred during those same hours if the Marginal

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Resource were present. The difference could be expressed in a Loss Savings Factor associated with the avoided energy costs.

The Loss Savings Factor associated with avoided distribution capacity costs, however, would be different from the one associated with energy. This is due to two factors. First, as described in the PLR metric, only the peak distribution hours are of interest in calculating the PLR. Avoided losses during non-peak hours (e.g., mid-morning hours) are not relevant to the determination of avoided distribution capacity costs. Second, only the avoided losses in the distribution system are relevant to the distribution benefit calculation. Avoided losses in the transmission system should not be included.

Three Loss Savings Factors should be developed as shown in Table 1.

Table 1. Loss Savings Factors

| Loss Savings Factor | Loss Savings Considered |
|------------------------------|--|
| Avoided Annual Energy | Avoided transmission and distribution losses for every hour of the Load Analysis Period. |
| ELCC | Avoided transmission and distribution losses during the 100 peak hours in each year of the Load Analysis Period. |
| PLR | Avoided distribution losses (not transmission) at the distribution peak. |

When calculating avoided marginal losses, the analysis should satisfy the following requirements:

1. Avoided losses should be calculated on an hourly (not an annual) basis over the Load Analysis Period. This is because solar tends to be correlated with load and losses during high load periods exceed average losses.
2. Avoided losses should be calculated on a marginal basis. The marginal avoided losses are the difference in hourly losses between the case without the Marginal PV Resource, and the case with the Marginal PV Resource. Avoided average hourly losses are not calculated. For example, if the Marginal PV Resource were to produce 1 kW of power for an hour in which total customer load is 1000 kW, then the avoided losses would be the calculated losses at 1000 kW of customer load minus the calculated losses at 999 kW of load.
3. Calculations of avoided losses should not include no-load losses (e.g., corona, leakage current). Only load-related losses should be included.

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- Calculations of avoided losses in any hour should take into account the non-linear relationship between losses and load (load-related losses are proportional to the square of the load, assuming constant voltage).

PART 3 – ECONOMIC ANALYSIS

Avoided Energy Costs

Distributed solar reduces the wholesale cost of energy in two respects. First, it reduces the quantity of energy procured in the MISO market for delivery to customers. Solar production displaces energy that would have been procured at a given price in a given hour. Second, it lowers demand for energy, resulting in lower clearing prices for all transactions, an effect sometimes referred to as the “market price response.”

The goal of the valuation analysis is illustrated in Figure 3, which shows the relationship between price and load in a given hour. As load increases (or decreases), the price similarly increases (or decreases). This relationship reflects the supply and demand of resources participating in the market.

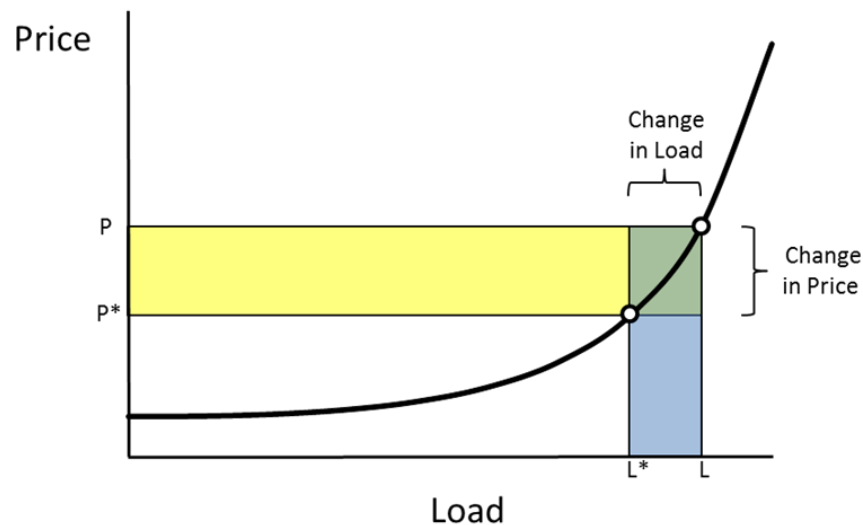


Figure 1. Avoided Energy Cost (Illustrative)

In this illustration L represents the measured load in any given hour, and P represents the corresponding price (the MISO day-ahead clearing price). The Marginal PV Resource reduces load from L to L^* and price from P to P^* . This reduces the total wholesale cost of energy from LP to L^*P^* and the savings are represented by the shaded regions.

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The calculation of savings may be performed in two steps. The first step is to multiply the observed market price P by the change in load (the blue area). The change in load is the PV fleet production for the hour. This is done for each hour of a sample year and summed.

The second step is to multiply the resulting load L^* by the reduction in price. This requires an estimate of the change in price which may be obtained from a model such as the one illustrated in Figure 2. This shows hourly load-price points for a given month at a sample ISO. From these points a model F may be developed as a least squares curve fit. Then, the analysis can assume that the change in price from P to P^* is proportional to the change in F . The calculation is done for each hour of the year and summed.

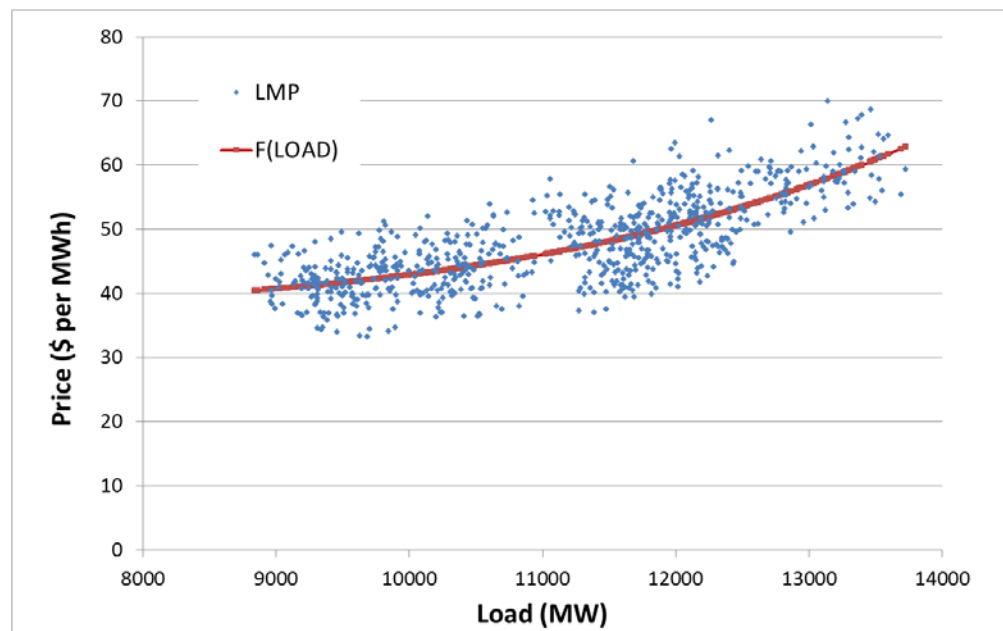


Figure 2. Load Versus Price Model F

Avoided Cost of Resource Adequacy

Part 2 described a method for calculating ELCC, a measure of the effectiveness of distributed solar resources in meeting resource adequacy requirements. The avoided cost, then, is calculated by multiplying the ELCC by the cost of new entry (CONE) for the LRZ. CONE indicates the annualized capital cost of constructing a new plant.

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CONE is calculated by MISO³ by annualizing the net present value (NPV) of the capital cost, long term O&M costs, insurance and property taxes. There are other measures of capital cost,⁴ such as the MISO planning auction, but these do not necessarily correspond to the long-term (e.g., 25 year) service provided by solar.

Voltage Regulation

Distribution utilities have the responsibility to deliver electricity to customers within specified voltage windows as required by State rules. When PV or other distributed generation resources are introduced onto the grid, this can affect line voltages depending upon generator rating, available solar resource, load, line conditions, and other factors. Furthermore, at the distribution level (in contrast to transmission) PV systems are more geographically concentrated. Depending upon concentration and weather variability, PV could cause fluctuations in voltage that would require additional regulation.

In some cases, these effects will require that utilities make modifications to the distribution system (e.g., adding voltage regulation or transformer capacity) to address the technical concerns. For purposes of this methodology, it is assumed that such costs are born by the solar generator. Consequently, no cost is assumed related to interconnection costs.

Advanced Inverters

Advanced inverter technology is available to provide additional services which may be beneficial to the operation of the distribution system. These inverters can curtail production on demand, source or sink reactive power, and provide voltage and frequency ride through. These functions have already been proven in electric power systems in Europe and may be introduced in the U.S. in the near term once regulatory standards and markets evolve to incorporate them.

Based on these considerations, it is reasonable to expect that at some point in the future, distributed PV may offer additional benefits, and voltage regulation benefits may be included in a future methodology.

³ See “Cost of New Entry: PY 2016/17,” at:

<https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/SAWG/2015/20151029/20151029%20SAWG%20Item%2004%20CONE%20PY%202016-2017.pdf>

⁴ See “Michigan Public Service Commission Solar Working Group – Staff Report” at

<https://efile.mpcc.state.mi.us/efile/docs/17752/0045.pdf>

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Avoided Transmission Capacity Cost

Distributed PV has the potential to avoid or defer transmission investments, provided that they are made for the purpose of providing capacity, and provided that the solar production is coincident with the peak. The challenge is finding the cost of future transmission that is avoidable or deferrable as a result of distributed generation. As a proxy for this price, transmission tariffs used to recover historical costs may be used.

In the MISO footprint, network transmission service to load is provided under the Open Access Transmission Tariff (OATT) as a per-MW demand charge that is a function of monthly system peaks. Using the PV Fleet Production Profile and the hourly loads of the zone, the average monthly reduction in network load may be calculated for the Marginal PV Resource. For example, the reduction in January network load for a given year would be calculated by first subtracting the PV Fleet Production from load every hour of the month. Then, the peak load for the month without PV is compared to the peak load with PV, and the difference, if any, is considered the reduction in network load for that month. A similar analysis would be performed for the remaining 11 months of the year. For each month, the reduction in peak demand would be multiplied by the zonal network price in the OATT Schedule 9.

Avoided Distribution Capacity Cost

In calculating the avoided distribution cost, the PLR is used as the load match factor. This is multiplied by the NPV of distribution capacity over the Economic Study Period. For example, if the Economic Study Period is 25 years, then the cost of new distribution capacity within the geographical area of interest should be estimated for each year in this period.

Detailed cost estimates are generally available only for areas facing near term capacity upgrades, making it difficult to perform this analysis. Therefore future costs outside the planning horizon may be made based on a projection of costs and peak loads over a representative historical period, such as the last 10 years, and must correspond to anticipated growth rates. Costs for reliability-related purposes should not be included because they are not avoidable by distributed solar.

PART 4 – OUT OF MARKET BENEFITS

Avoided Environmental Cost

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With distributed PV, environmental emissions including carbon dioxide (CO₂), sulfur dioxide (SO₂), and nitrous oxides (NO_x) may be avoided. In general, it is relatively straightforward to calculate the technical impact—for example, through the use of the Environmental Protection Agency’s AVERT tool—but the estimates of avoided social costs are more difficult to quantify.

Estimates of social costs must be taken from external studies. The social cost of carbon, for example, may be based on results from the Interagency Working Group on Social Cost of Carbon.⁵

It should be noted that costs to comply with environmental standards (scrubbers, etc.) are embedded in the energy costs already described. The technical calculations of emissions should therefore already take into account the compliance measures used to reduce emissions. The social costs are therefore associated with the emissions after compliance has been met (the “net” emissions) and the costs are therefore in addition to compliance.

Fuel Price Guarantee

This value accounts for the fuel price volatility of natural gas generation that is not present for solar generation. To put these two generation alternatives on the same footing, the cost that would be incurred to remove the fuel price uncertainty may be included. This can be accomplished by estimating the natural gas displaced by PV over the Economic Study Period and determining the cost of natural gas futures required to eliminate the uncertainty.

Note that price volatility is also mitigated by other sources (wind, nuclear, and hydro). Therefore, the methodology is designed to quantify the hedge associated only with the gas that is displaced by PV.

PART 5 – IMPLEMENTATION OPTIONS

Evaluation of Existing Net Metering Programs

A valuation using the above methods would result in the avoided costs per kWh of distributed solar generation. This valuation could then be used to evaluate the question of whether solar

⁵ The annual Social Cost of Carbon values are listed in table A1 of the Social Cost of Carbon Technical Support Document, found at: <http://www.whitehouse.gov/sites/default/files/omb/assets/inforeg/technical-update-social-cost-of-carbon-for-regulator-impact-analysis.pdf>.

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customers under net energy metering (NEM) rates are subsidizing non-solar customers or whether non-solar customers are subsidizing NEM customers.

NEM customers are only billed (or credited) for the difference between their consumption charges and their generation credits. It has been argued that fixed costs recovered through volumetric rates may not be recovered equitably because NEM customers are able to reduce their monthly net consumption. On the other hand, NEM customers may provide additional benefits, resulting in savings to other customers. For example, a NEM customer may be delivering energy and capacity to the grid at times when it is most valuable. Using the methods described here can help to determine whether cost shifting is taking place and the direction of cost shifting (whether solar customers are subsidizing or being subsidized by non-solar customers, as the case may be).

Considerations for Community Shared Solar

Some customers do not have good options to install solar on their rooftops. They may not own their building (especially in the case of commercial customers), the building may be heavily shaded, or it may not lend itself to solar due to architectural considerations. For these, customers, community shared solar may be an option. Systems built for this purpose may be sited in more desirable locations with good solar access and may be built with higher ratings at lower cost per kW.

However, the methodologies described above may have to be adjusted. There are two factors that must be considered. First, the production profile of these systems will be different than that of the overall fleet as described in Part 2. These systems will be built at optimal orientation (e.g., south facing at an optimal tilt angle) in order to maximize the energy production. Therefore, the production profile associated with such an optimal design should be used rather than the fleet profile.

It should also be noted that the shared solar resource may be electrically distant from the member-customer. In a sense, the energy would have to travel from the shared resource to the customer, and this would include additional losses not accounted for in the methodology. However, the energy in practice would not be delivered to the specific customer but simply accounted for and credited through metering. The energy produced by the resource would still result in avoided losses, except that the losses would be avoided in delivering energy to non-members rather than to the members themselves. The methodology would provide a reasonable accounting of this benefit. Such would not be the case if the shared resource were outside of the service territory of the utility.

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Value of Exported Solar Energy

In some studies, the value of export energy is sought rather than the value of gross solar production. This may be the case, for example, in developing a tariff in which self-consumption is used to reduce a customer's electricity bill. Such a rate would effectively provide the customer-generator with two benefit streams: the benefit of lower utility bills due to self-consumption and the benefit of a bill credits associated with the value of export energy. From the utility perspective, such a mechanism also results in two impacts: lost revenue from the self-consumption and lost revenue associated with those bill credits that are exercised.

Regardless of perspective—customer or utility—the economic analysis requires as study inputs the hourly load profile and the relative size of the solar system and the load. This data is necessary to calculate the hourly export profile, and this is a different shape and magnitude than the gross production. If solar generation is self-consumed during the daytime, the mid-day export may be low or non-existent, in contrast to the PV Fleet Production Profile described in this methodology. This means that the capacity value will be different since it is dependent upon the match of between solar and load.

Customers have a choice in sizing their systems. Depending upon size, more or less energy will be delivered to the grid as export energy. Therefore, a study of the export energy value would have to include scenarios that handle these size variations. For example, scenarios could be developed in which solar provides 100%, 75%, 50% and 25% of the annual energy.

Finally, the details of the customer load profile are important. One residential customer, for example, may have a different load profile than another. The export energy profile will therefore be different even if other factors such as system design are the same.

Including multiple scenarios of relative size and profile shape may prove impractical due to the additional technical effort to address each scenario as well as the complexity in determining which result to apply to a given customer. Therefore, the study approach might consider just one or a small number of representative scenarios as an approximation.

Qualifying Facilities Rates

Many of the methods described here could be used to help identify a solar-specific avoided cost rate for qualifying facilities under PURPA. The resulting rate would incorporate many of the solar-specific attributes, such as the hourly production profile, intermittency, and loss savings.

Applicability to Other DER Technologies

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Aspects of this methodology may be used for other DER technologies, such as storage and efficiency. However, the PV Fleet Production Profile would have to be replaced with a profile suitable to the technology. For example, energy storage may have a profile that includes off-peak charging and on-peak discharging. If the profile were known, or if they were assumed in a scenario analysis, then the rest of the methodology could be used to calculate the value of these resources.

Real Time Pricing with AMI

In some cases, such as storage (a dispatchable resource), the customer has control of its operation, so the generation profiles may not be known. Value-based rates calculated using an assumed production profile might therefore not be valid for these cases.

If the goal of the valuation is to develop a mechanism for compensation, the methodology may be adapted for use in a technology-neutral value-based rate using real-time pricing. In this case, the DER profile may be determined at the conclusion of the billing month and applied against actual energy prices (e.g., LMPs). In the case of storage, the charging or discharging periods would correspond to energy charges and credits. Capacity value could be fixed for non-dispatchable resources but could require adherence to resource qualification standards similar to the MISO standards and utility control (or penalties for not dispatching during critical peaks).

Value of Solar Tariffs

Value of solar tariffs (or VOST) were introduced by Austin Energy in 2012 and by Hawaiian Electric in 2015. These tariffs intend to provide compensation for solar based on value. Austin Energy, for example, uses a methodology similar to the one described here and incorporating market-based prices in ERCOT. The Hawaiian Electric “grid supply” option provides for self-consumption and a rate for export energy based on marginal energy costs.



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**COMMENTS OF THE INDEPENDENT POWER PRODUCERS COALITION
OF MICHIGAN (IPPC) ON THE STAFF'S DRAFT REPORT ON THE
CONTINUED APPROPRIATENESS OF THE COMMISSION'S
IMPLEMENTATION OF PURPA**

April 1, 2016

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A. The focus of any avoided cost methodology should be on the *utility's* avoided cost. The absence in Staff's Draft Report of discussion on this point or examination of utility costs are fatal to Staff's effort to achieve an avoided cost rate that complies with federal law.4

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APPENDIX: Comments by Kenneth Rose on the MPSC Staff Draft Report for the PURPA Technical Advisory Committee

April 1, 2016

**COMMENTS OF THE INDEPENDENT POWER PRODUCERS COALITION OF MICHIGAN (IPPC) ON
THE STAFF'S DRAFT REPORT ON THE CONTINUED APPROPRIATENESS OF THE COMMISSION'S
IMPLEMENTATION OF PURPA**

I. Introduction

The IPPC appreciates this opportunity to comment on the Michigan Public Service Commission ("MPSC" or "Commission") Staff's Draft Report on the Continued Appropriateness of the Commission's Implementation of the Public Utility Regulatory Policy Act of 1978 ("PURPA") ("Staff Draft Report"). The Staff's Draft Report provides good background information on the MPSC PURPA Technical Advisory Committee ("PURPA TAC"), and highlights several important areas to be considered and discussed in any avoided cost methodology, including some of the statutes and regulations affecting Qualified Facilities ("QF" or "QFs") in Michigan that are 20 MW and smaller.

While the IPPC particularly appreciates Staff's recommendation that QF facilities 5 MW and smaller be allowed to elect a standard rate and to recover the Staff's calculated full avoided cost capacity rate and one of three energy component payment options, we nevertheless have concerns that the Staff's method for calculating full avoided cost capacity does not truly reflect avoided costs – as discussed more fully below. This problem is exacerbated for facilities with high capacity factors (above 80%), and produces an avoided cost structure that is approximately 30% below current avoided cost payments for these facilities. It is hardly credible that capacity prices have plummeted to that extent, particularly when both major Michigan utilities continue to come in yearly for rate increases. A sudden reduction in the capacity payment of this magnitude

would force most, if not all, of these affected QFs to likely cease operations in the state. Clearly such a result would contravene the purpose of PURPA to reduce barriers for these facilities.

In fact, each of the three capacity payment options Staff provides appears to reflect an attempt to find the lowest possible cost option rather than the measure of a utility's actual full avoided costs. As a consequence, each of the options discounts or provides only a fraction of a true full avoided cost capacity rate. On their face, all three of the capacity payment options would result in rates that discriminate against Michigan's QFs. Furthermore, these rates would not be in the public interest, in that the economic, social and environmental benefits provided by these facilities would cease. Such a capacity payment structure would be a clear violation of the plain meaning of PURPA. CFR 292.304(a). With these strong objections in mind, the IPPC provides the following comments on Staff's Draft Report.

II. The MPSC's avoided cost methodology must meet the federal law's requirement that avoided costs be just and reasonable as applied to a qualified facility, in the public interest, and not discriminate against the state's qualified facilities. The avoided cost methodology proposed by Staff would be discriminatory and would violate federal laws protecting QFs in Michigan 20 MW and smaller.

A. The focus of any avoided cost methodology should be on the *utility's* avoided cost. The absence in Staff's Draft Report of discussion on this point or examination of utility costs are fatal to Staff's effort to achieve an avoided cost rate that complies with federal law.

A fundamental underpinning of any avoided cost methodology is an examination of the *utilities'* costs – *i.e.*, those that are avoided by obtaining renewable energy and capacity from a QF. While Staff broke down an example of factors that may be considered in determining such cost avoidance, including dispatch and reliability, deferral of capacity additions, the reduction of fossil fuel use, and costs or savings resulting from variations in line losses from those that would

have existed in the absence of purchases from a QF,¹ Staff was remiss in the Draft Report to actually examine or attempt to apply any of these factors. Application of such factors that would have led to more favorable QF rates were not considered, according to the draft report, in order to "keep the process more streamlined."² Instead, discounted market rates and the lowest cost possible proxy unit – both of which clearly benefit a utility at the expense of a QF – were considered and recommended. A fear of complexity or the level of effort required to examine the benefits that a QF provides is not, however, an adequate excuse for ignoring the clear directives of federal law. The PURPA regulations require that "[i]n determining avoided costs, the following factors shall, to the extent practicable, be taken into account." 18 CFR 292.304(e). The use of "shall" makes the duty mandatory, unless the burden is met of demonstrating that such an accounting is not "practicable." There was no such showing of impracticability in the Staff Draft Report.

The Federal Energy Regulatory Commission ("FERC") has clearly spelled out five factors in determining an avoided cost calculation: (1) a utility's system costs, (2) contract duration, (3) QF availability during daily or system peaks, (4) the relationship of the availability of the QF's energy or capacity to the ability of the utility to avoid costs, and (5) costs or savings from line losses from what would have existed in the absence of the QF purchases.³ The failure to examine utilities' actual avoided costs, combined with a failure to consider the system benefits that a QF provides, such as savings from line losses, resulted in an unfair and unreasonable

¹ Staff Report, Figure 5, p.13.

² Staff Report, p. 30.

³ Federal Energy Regulatory Commission (FERC) "Order Granting Clarification and Dismissing Rehearing." 133 FERC ¶ 61,059, Docket EL10-64-001 (California Public Utility Commission) and Docket EL10-66-001 (Southern California Edison, Pacific Gas and Electric Company, and San Diego Gas & Electric Company), Issued October 21, 2010. <http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=12468361>.

avoided cost methodology. In fact, the hybrid methodology that is being proposed would fall so short of a just and reasonable energy and capacity rate – amounting to an approximately 30% or more *decrease* in current avoided costs paid to these facilities – that it would certainly violate PURPA's legal requirement of a fair rate set by a state public service commission for QFs in the state.

As Staff knows, PURPA imposes a number of legal obligations on regulated utilities. PURPA requires that purchases by electric utilities from QFs subject to the “must purchase” obligation be 1) “just and reasonable to the electric consumers of the electric utility and in the public interest,” 2) non-discriminatory “against qualifying generators or qualifying small power producers,” and 3) shall not require “a rate which exceeds the incremental cost to the electric utility of alternative electric energy” or its “avoided cost.” See 16 U.S.C. § 824a-3(b) and 18 CFR 292.101 *et seq.*

The Staff Draft Report appears to lean in the direction of arguments that avoided costs reflect only the marginal increment (*i.e.*, excess) of short-term qualified energy and capacity costs – much like utilities purchase and sell “extra” energy and capacity from the MISO market. Utilities argue that these marginal costs are the *least* expensive cost to their customers. However, that is not what the federal law directs. As the IPPC has repeatedly maintained, avoided costs are not the lowest cost to the utility, because that would discriminate against the QF; instead they are the *full* costs that the utility avoids by purchasing QF energy and capacity.⁴

⁴ On avoided costs not being the lowest possible costs, see the discussion in “Order Granting Clarification and Dismissing Rehearing.” 133 FERC ¶ 61,059, Docket EL10-64-001 (California Public Utility Commission) and Docket EL10-66-001 (Southern California Edison, Pacific Gas and Electric Co., and San Diego Gas & Electric Co.), Issued October 21, 2010. <http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=12468361>

It is similarly true that avoided costs are not the most expensive costs to the utility – as that would not be just and reasonable to the utility's customers.

A review of the avoided cost factors in 18 CFR 292.304(e) shows that obtaining the lowest cost is not one of the driving considerations in determining an avoided cost rate, but rather avoided costs should reflect the real and full costs the utility avoids incurring, including various system and other benefits, when it obtains QF energy and capacity. Thus, the law requires that the resulting costs to the utility to meet its must purchase obligations be “just and reasonable to the electric consumers” and “in the public interest,” not that it be the cheapest source available. 18 CFR 292.304(a)(1)(i). Simply finding “the lowest incremental cost” possible would violate PURPA's requirement of a just and reasonable rate to the QF.

As the IPPC presentations illustrated, there are a number of public interests involved in continuing the operations of these QFs besides the obtaining of cost-effective capacity and energy. It is consistent with federal law for the avoided cost determination to reflect such public interests. Furthermore, as Ken Rose noted in his presentation, and has reiterated in the attached comments, avoided cost means “the incremental cost of the utility to generate or purchase itself without the QF or QFs – over the relevant utility planning horizon.” And he added, “that is, long term that takes into account capital expenditures.” See Ken Rose presentation to PURPA – TAC, 02-03-2016, slide 8.

B. Staff’s Modified Proxy Plant Methodology ("Staff's Strawman") fails to reflect just and reasonable avoided costs, and thus would violate PURPA.

Staff's recommended avoided cost methodology, particularly for QFs 5-20 MWs, referred to as the "Staff's Modified Proxy Plant Methodology" or "Staff's Strawman," utilizes a

combination of a proxy unit and market-based pricing methodologies. This methodology, as presented, fails to meet the requirements under PURPA for a just and reasonable avoided cost methodology for several reasons.

1. **Staff's use of a CT proxy for capacity, and reliance on CONE in its model fails to satisfy PURPA requirements.**

First, for the capacity component, Staff utilizes a proxy unit of a combustion turbine natural gas plant ("simple cycle," or "CT"), due to the fact that it is similar to MISO's calculation of the Cost of New Entry ("CONE"). Staff's reasoning for this methodology is that it would allegedly "mitigate the risk of re-evaluation of PURPA avoided cost rates."⁵ However, to the contrary, the methodology is so woefully inadequate as a true reflection of avoided costs that it produces a capacity payment structure that is punitive to QFs in the state, particularly those with capacity factors in the 80-90% range. As such, it would most certainly result in legal and regulatory appeal proceedings to establish more just and reasonable avoided costs.

As the IPPC previously stated, the use of a CT for proxy purposes is problematic for several reasons. First, it is widely acknowledged that the next build – if new generation is required – will be a natural gas combined cycle plant ("NGCC"). Even the Jackson plant that Consumers Energy recently purchased was a NGCC. Equally important, the relatively low cost of that recent purchase – by the company's own admission – was a stop-gap effort in "deferring, not canceling," plans to build its proposed \$700 - \$800 million Thetford NGCC plant.⁶

⁵ Draft Report at p. 18.

⁶ Consumers Energy to Buy Natural Gas Plant in Jackson, January 18, 2016, <https://consumersenergyinyourcommunity.wordpress.com/2014/01/30/consumers-energy-to-buy-natural-gas-plant-in-jackson/>; see also Case No. U-17429.

Furthermore, the problem with a CT proxy is that it is not a reasonable basis for the proxy choice under federal law, which require not the *lowest* cost choice, but the one that the utility itself would build if it were not for the presence of the QFs. See, *PURPA Title II Compliance Manual*, “Proxy resource method,” p. 35. There was nothing presented to the workgroup that would make a compelling case for anything different than a NGCC as the proxy unit. Utilization of the CT unit as proxy would unfairly reflect true avoided costs of Michigan's utilities, in violation of PURPA.

Second, the use of MISO's market to quantify capacity payments is discriminatory to Michigan's QFs and violates federal PURPA laws. The Staff propose three options for capacity payment, but leaves the final choice to the Commission. This is problematic, as it simply delays to the contested case the important discussion of how capacity payments should be calculated. For purposes of comment here, IPPC is focusing on Options 1 and 2 that Staff presented. This does not imply IPPC agreement with the methodologies suggested for Option 3. However, as it would appear that IPPC members would all most likely fall under Options 1 or 2, those options will be the focus of our comments here.

Option 2 appears to be the same as Option 1 in terms of how avoided costs are calculated, differing only in when those avoided costs would be paid. Thus, Option 1 provides for payment of avoided capacity costs, while Option 2 provides for payment calculated in the same manner as Option 1, but only when the Commission has determined that the utility or its LRZ require capacity. Therefore, for purposes of discussion of the capacity payment, Options 1 and 2 are essentially identical and will be discussed as together.

While Staff's "full avoided capacity rate" is nominally a proxy plant method, it does rely on MISO's CONE as the foundation for key determinants. For this reason, and because it is

based on the lowest cost capacity (simply cycle gas turbine) rather than the commonly accepted next build (NGCC), IPPC finds the rate to be objectionable and probably unlawful. Both the use of a simple cycle plant, and the use of CONE as the foundation for key determinants in the Staff's levelized cost calculation in Figure 9, reflects an attempt to find the lowest capacity payment. As discussed above, using lowest cost as an avoided cost factor violates PURPA.

Furthermore, there are problems with using MISO market constructs such as CONE as cost benchmarks. As MISO recently noted, its markets are not constituted to provide a true reflection of capacity costs, since most utilities in MISO's footprint are integrated utilities that do not rely on the market for capacity needs. Thus, MISO observed that "the current market will continue to provide only a balancing function and will fail to efficiently support resource investment decisions in those areas of MISO that rely upon MISO's market price signals for those decisions."⁷

2. Staff's use of Locational Marginal Price is inappropriate and a violation of PURPA.

Use of Locational Marginal Price ("LMP") for calculating energy avoided costs for Michigan QFs 20 MW and smaller would be discriminatory towards the QFs and would thus violate PURPA. Levelized Costs, and not LMP Day Ahead Prices, are the appropriate cost measure.

First of all, as previously stated, IPPC believes that the MISO LMP at the appropriate node is not a reasonable proxy for avoided energy costs of the utility. For one thing, QF contracts in Michigan have traditionally been long-term contracts, and the LMP does not reflect

⁷ MISO Staff Proposal, Competitive Retail Solution, March 18, 2016, p. 2, see: <https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/CRSTT/Draft%20CR%20FCA%20Proposal%20CoreDesign.pdf>.

any long-term forecast of energy costs. Staff's second option, the levelization of projected LMP over the contract term, at least has the benefit of attempting to account for the value over time of the energy being provided. That being said, the LMP, even levelized over time, does not capture the true avoided costs, as required by PURPA.

IPPC believes that the most appropriate and reasonable manner to address the energy component is to use the third option the Staff has provided – the levelized variable costs of a combined cycle natural gas plant over the contract term, consistent with how the Commission utilizes this proxy for its Transfer Price Schedule. As IPPC believes that such a plant should be the basis for the capacity calculation, this would have the virtue of being a consistent application of the proxy model across all costs, which is the most reasonable way to apply the model.

Using a levelized cost rather than spot market costs better reflects the utility's long-range planning horizon. It would not be prudent operation for any utility to base its determinations about making long-term purchases of energy, or about building more generation, on spot market prices. Instead, any prudent utility looks at long-term trends in fuel costs, load growth, and other factors. None of these factors is reflected in the spot market price, and so that price does not satisfy the federal requirement that the avoided cost must reflect the costs that the utility is avoiding by not having to generate itself or purchase from another source because of the (long-term) contracts that it has entered into with QFs. See 18 CFR 292.101(b)(6).

Use of levelized costs and long-term contracts also provides a hedge for the utility against fuel and generation cost increases over the planning horizon. Again, this is not a benefit that can be reflected in the spot market cost, but which the avoided cost rate should reflect.

C. The IPPC continues to support the methodology utilized in the Commission's long-standing Transfer Price Schedule as the best representation of what a true avoided cost methodology should be.

The IPPC strongly believes that there is no better representation of what a true avoided cost template should look like than that which has been used over the past 9 years by the Commission in its Transfer Price Schedule. As this Commission recently stated in its 2016 Renewable Energy Report:

(t)ransfer price schedules are representative of what a Michigan electric provider would pay had it obtained the energy and capacity (the non-renewable market price component) through a new long term power purchase agreement for traditional fossil fuel electric generation. To best determine the value of the non-renewable component of Act 295 compliant generation, Commission Staff determined, for purposes of developing a uniform Transfer Price Schedule, that the levelized cost of a new NGCC plant would likely be analogous to the market price mentioned above.^[8]

Use of the Transfer Price Schedule as the proxy for avoided cost, since it is itself based on a NGCC unit, is the appropriate proxy for the avoided cost, and would satisfy the obligation under PURPA to be just and reasonable and in the public interest. In fact, it has already been found to satisfy those criteria in multiple Commission proceedings. Furthermore, since the Transfer Price Schedule offers a projected cost over a multi-year horizon, it also offers the opportunity to establish an avoided cost schedule that could be the basis of a multi-year power purchase agreement.

During the PURPATAC meetings, concerns were raised that use of the Transfer Price Schedule could raise problems due to it being tied to statutory provisions that are currently being

⁸ Report on the Implementation of the P.A. 295 Renewable Energy Standard and the Cost-Effectiveness of the Energy Standards, Michigan Public Service Commission, February 12, 2016 ("2016 Renewable Energy Report"), at pp. 32-33.

amended and perhaps deleted in pending legislation. This should not pose a real barrier to the use of the Transfer Price Schedule methodology, however. Even were the Transfer Price Schedule requirements removed from statute, the methodology to calculate that schedule could continue to be applied by the Commission for PURPA avoided costs, and since it has already been challenged and found to be a just and reasonable measure of the utility's own costs to add capacity and energy, it would address the Staff's concern to "mitigate the risk of re-evaluation of PURPA avoided cost rates."

IPPC believes that the previous work of the Commission on avoided costs, as reflected in dockets U-6798 and U-8871, should be respected; and while it needs to be updated, the essential model adopted there is still appropriate and relevant for establishing avoided costs for Michigan's PURPA QFs. We believe that the Transfer Price Schedule, using as it does a proxy generation unit, is consistent with the approach taken in the previous dockets.

D. The utility's long-range planning must include the existing capacity from QFs under contract

The utilities' obligation to purchase energy and capacity from QFs has existed for over 25 years, and those facilities that have long been part of each utility's long-range planning for capacity and energy. As such, QFs with existing capacity contracts should enjoy a presumption, when their contracts are due for replacement or renewal, that the utility will continue to be obligated to purchase their capacity going forward. This presumption simply recognizes that the utility has a continuing federal legal obligation to purchase capacity and energy from the QF so long as the QF continues to offer it, even upon termination of the existing contract. A utility should not be able to claim that it no longer needs the QF's capacity (perhaps in the hope that it will be able to build and rate base a new generation source itself) unless there is some

extraordinary reason, such that the continued purchase of the QF's capacity is no longer in the public interest. This approach does not raise the risk that Staff expressed concerns about – that as in Idaho the number of QFs seeking capacity sales would exceed the total capacity requirement of the utility. Whether or not new QF capacity is needed is a determination that should be left to the Commission, and not to the utility itself, since the latter clearly has a conflict of interest.

E. PURPA QFs should retain Renewable Energy Credits

IPPC supports Staff's recommendation that all Renewable Energy Credits ("RECs") belong to the QF when the choice of proxy plant does not generate RECs, thus allowing the sale of RECs to the utility to be an issue negotiated between the QF and the utility outside of the avoided cost calculation. Because the proxy that Staff is proposing is based on a fossil fuel fired generation source, and so does not account for any of the renewable benefits of the QFs, those renewable benefits should belong to the QF unless they are otherwise contracted for between the QF and the utility. To do otherwise is to arbitrarily take value provided by the QF and give the utility the benefit of that value without concomitant payment to the QF. IPPC recognizes that the value of RECs and other means of measuring the renewable benefits provided by QF generation are difficult to project and subject to dispute, and so we propose that rather than trying to assign these a value they be left with the QF, unless the utility wishes to acquire them, in which case their value will be determined in arms-length negotiation between the parties.

III. Sources of avoided cost data

First, IPPC has strong concerns about the avoided cost models proposed in the Staff-recommended administrative process found in Figure 3. The second box says that the

Commission should issue an Order, "directing Utilities to file avoided cost calculations and Section 292.302 avoided cost data according to the Staff Recommended Proposal and any additional calculation methodology requested by the utility." It is clear that the utilities must provide their system cost data as required by federal law under 18 CFR 292.302. However, allowing them to present two models – their own and the Staff's – unfairly biases the proceeding against models proposed by any other party. A more fair method would be to require the utility to file their cost data, and then to have all the parties (including the utility and Staff) use that data or any other data they believe to be appropriate and defensible to file their own models. Since the PURPA workgroup was unable to achieve a consensus on the model to be adopted, beginning the proceeding with the models championed by only two of the several participating parties (Staff and the utility) provides an undue preference for those models.

Second, the IPPC has identified several possible sources of cost data that the Commission could use, all of which have been used in one way or another in MPSC cases recently, or are otherwise government-authorized numbers and so are less likely to be subject to accusations of bias in their derivation. If not used directly, these data at a minimum should be used to verify the reasonableness of the avoided cost derived through the MPSC's chosen methodology.

A. EIA data

In its Annual Energy Outlook 2015, EIA provided levelized costs and avoided costs for new generation both nationally and on a regional level. These numbers are updated annually.

http://www.eia.gov/forecasts/aeo/electricity_generation.cfm

B. The utility's recently filed data

Consumers provided what it at the time argued were its just and reasonable costs for its next source of generation in the Certificate of Necessity docket, U-17429. Consumers provided levelized cost of generation in Exhibit A-35: \$100.89 – 125.05 / MWH. Similarly, Consumers and DTE have both added capacity at the Ludington Pump Storage Facility. The filed costs of that capacity addition can serve as one benchmark for capacity prices on their systems.

APPENDIX

Comments by Kenneth Rose on the MPSC Staff Draft Report for the PURPA Technical Advisory Committee

The draft report by the MPSC staff has done a good job to help set the tone for discussion to develop a revised approach to PURPA implementation in Michigan. While there is still some disagreement on the details, the overall framework the staff proposed will help guide the process forward as the details get worked out.

However, judging from the comments made at the MPSC TAC meetings and other places, it appears that an important point of disagreement centers on the calculation of avoided costs. This is not too surprising since this has always been one of the more difficult issues faced in PURPA implementation over the years. Confusion and disagreement has increased with the changes in wholesale market structure and FERC's implementation of the Energy Policy Act of 2005. These short comments are an attempt to explain how avoided costs should be calculated, specifically in light of the wholesale market availability.

FERC defines avoided cost as "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source." (18 CFR sec. 292.101(b)(6)). What is meant by "avoided cost" in this context?

FERC Order 69 divided avoided costs into its two components, costs which an electric utility can avoid by purchases from a QF—that is - energy cost and capacity costs. Energy costs are the variable costs associated with the production of electric energy (kilowatt-hours). They represent the cost of fuel and some operating and maintenance expenses. Capacity costs are the costs associated with providing the capability to deliver energy, including the capital costs of generation facilities. Section 210 of PURPA clearly states that rates for purchase by electric utilities "(1) shall be just and reasonable to the electric consumers of the electric utility and in the public interest, and (2) shall not discriminate against qualifying cogenerators or qualifying small power producers." PURPA also states that the rates for purchase does not have to exceed the incremental cost of the electric utility either. Congress clearly intended that QFs be treated by a utility in a nondiscriminatory manner, *as if the power was coming from the utility's own facilities or purchased from another source.*

Because of the phrase "purchase from another source," it might be tempting to say (as some have said at the TAC meetings) that energy purchased in a wholesale energy market represents the incremental cost of the utility. However, there are two problems with that approach. First, exchanges for energy in a wholesale market are short-term energy-only and are not the same as a purchase power agreement by the utility for full requirements power supply in a wholesale transaction. Therefore, this does not represent the utility's avoided energy cost. Second, the energy market itself, in Michigan's case operated by MISO and PJM, are short term or spot sales, at best, and are largely based on the bids submitted by the utilities themselves. Moreover, without going into detail here, the MISO capacity market is also inadequate for

determining a capacity cost to represent a utility's capacity cost (a point of complaint often from utilities themselves). Therefore, relying on the RTO energy and capacity markets for determining avoided costs would violate PURPA's obligation to treat QFs as if the power was being supplied by the utility itself.

In FERC Order 69, the Commission offered a simple example that illustrates this point of how avoided cost should be determined: “[o]ne way of determining the avoided cost is to calculate the total (capacity and energy) costs that would be incurred by a utility to meet a specified demand in comparison to the cost that the utility would incur if it purchased energy or capacity or both from a qualifying facility to meet part of its demand, and supplied its remaining needs from its own facilities. The difference between these two figures would represent the utility's net avoided cost” (FERC Order 69, at 12216). Clearly FERC was offering a way to meet the PURPA mandate—that is, calculate the avoided cost in a way that treats the QFs in a nondiscriminatory manner as if the power was supplied by the utility itself.

In addition, and more recently, FERC determined that QFs of 20 MW or less are presumed to not have non-discriminatory access to competitive markets, as the Commission described in their rulemaking (§292.309(d)(1)). In this case, FERC is recognizing that small QFs, in particular, do not have the same access to the RTO markets that a utility or a large independent supplier would have, and that the PURPA obligation on utilities still holds.

The methodology the staff proposed in the draft report, in part, by using RTO energy and capacity markets as a proxy for calculating utility avoided cost, clearly would violate both FERC rules and the intent of PURPA. I ask that the MPSC staff specifically and clearly acknowledge that in their final report.