STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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| In the matter, on the Commission's own motion, commencing an investigation into the continuing appropriateness of the Commission's current regulatory implementation of the Public Utility Regulatory Policies Act of 1978. | ) | Case No. U-17973 |

At the October 27, 2015 meeting of the Michigan Public Service Commission in Lansing, Michigan.

PRESENT: Hon. John D. Quackenbush, Chairman
Hon. Sally A. Talberg, Commissioner
Hon. Norman J. Saari, Commissioner

**ORDER COMMENCING INVESTIGATION**

It has been many years since the Commission last thoroughly considered the related subjects of the Public Utility Regulatory Policies Act of 1978, Pub L No. 95-617, 92 Stat 3117 (PURPA) and the avoided cost payments that a public utility may be obligated to pay to a Qualifying Facility (QF). Recently, the Commission Staff (Staff) briefed the Commission on PURPA issues. In preparation for the briefing, the Staff drafted a status report, an updated version of which is appended to this order.

The Staff's *Status of PURPA* report draws information from a lengthy March 2014 report titled "*PURPA Title II Compliance Manual"* (PURPA Manual), which was issued jointly by the American Public Power Association, Edison Electric Institute, the National Association of

Regulatory Utility Commissioners, and the National Rural Electric Cooperative Association.[1] It also relied on a variety of other resources including an analysis prepared by Carolyn Elefant, JD, entitled *REVIVING PURPA'S PURPOSE: The Limits of Existing State Avoided Cost Ratemaking Methodologies In Supporting Alternative Energy Development and A Proposed Path for Reform,*[2] and an April 1993 National Regulatory Research Institute report by Robert E. Burns and Mark Eifert entitled *A WHITE PAPER ON THE ENERGY POLICY ACT OF 1992: AN OVERVIEW FOR STATE COMMISSIONS OF NEW PURPA STATUTORY STANDARDS.*[3]

The Staff's briefing and report have persuaded the Commission that it should revisit its current regulatory response to the matters of PURPA and avoided cost. It is quite clear that conditions extant nearing the end of 2015 are significantly different than those faced in 1978 when PURPA became the law of the land. In 1978, the nation was exiting from a period of economic chaos and energy shortages attributable in large measure to the 1973-1974 oil embargo by the Organization of Petroleum Exporting Countries (OPEC). Coal was then the preferred fuel source for new electric energy generation in the country. A significant number of nuclear plants were under construction. Electric utilities remained vertically-integrated monopolies that were providing their captive customer bases with generation, distribution, and transmission services on a fully-regulated basis. There were no energy markets, alternative energy suppliers, or regional transmission organizations.

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[1] *See*, http://www.naruc.org/Publications/PURPA_Title_II_Manual.pdf.

[2] *See*, http://www.lawofficesofcarolynelefant.com/fercfights/wp-content/uploads/2011/10/Elefant_Reviving_PURPA_Avoided_Costs_2011.pdf.

[3] *See*, http://communities.nrri.org/home?p_auth=h1X6Qnbt&p_p_auth=7ze1UKn3&p_p_id=20&p_p_lifecycle=1&p_p_state=exclusive&p_p_mode=view&_20_struts_action=%2Fdocument_library%2Fget_file&_20_groupId=317330&_20_folderId=0&_20_name=5422.

Times have changed. Natural gas, not coal or nuclear, is viewed generally as the fuel preference for new generation plants. Nine coal-fired units in Michigan will be shuttered during the first half of 2016. Utility customers are allowed to shop for retail generation service.[4] Alternative electric suppliers (AESs) are allowed to become state licensed suppliers, and may compete against the traditional utilities in the retail market. Transmission services are provided by independent transmission suppliers. The Midcontinent Independent System Operator, Inc. (MISO), and PJM Interconnection, LLC (PJM), operate competitive wholesale energy markets. Moreover, some of the initial PURPA power arrangements between QFs and Michigan utilities are about to expire, and there is significant uncertainty over the future of these arrangements. Significant amounts of renewable energy have been added to the state's generating portfolio. Additionally, as observed in the Staff's report "[t]here is increasing interest in distributed generation in Michigan, primarily combined heat and power and solar. As a result of Michigan meeting the 10% renewable energy standard, utilities are no longer seeking contracts with third party generators. These generators are now turning to the PURPA avoided cost rate as an option for sales." Staff report, p. 2.

PURPA remains the law of the land. Although PURPA has been revised on several occasions,[5] one unique aspect of PURPA remains essentially unchanged. Ordinarily, wholesale power rates are within the sole jurisdiction of the Federal Energy Regulatory Commission (FERC). However, the task of determining the wholesale rates paid by utilities to QFs has been assigned to the states. Under Section 210(b) of PURPA the rate to be paid by a utility to a QF must be "just and reasonable" to the electric consumers of the utility and in the public interest. Also, the rate

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[4] Since 2008, shopping has been legislatively limited to 10% of a utility's load, subject to an exception for mines located in the Upper Peninsula for which shopping is not limited.

[5] *See*, the Energy Policy Act of 1992 (PL 102-486) and the Energy Policy Act of 2005 (PL 109-58). *See also,* FERC regulations implementing the PURPA changes, 18 CFR 292.309(2009).

shall not discriminate against cogenerators or small power producers. PURPA also provides that rates must not exceed the incremental cost to the electric utility of alternative electric energy. In the administrative rules promulgated by the FERC to implement PURPA, the Code of Federal Regulations (CFR) provides that PURPA rates must equal the utility's full avoided cost.[6]

Pursuant to PURPA, the Michigan Legislature empowered the Commission to address the requirements under PURPA pursuant to MCL 460.6j(13)(b):

> 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 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.

[6] The FERC intended a utility's avoided cost to be the ceiling price that a utility would pay a QF for capacity and energy. As such, the FERC reasoned that the utility's customers should be ambivalent to the source of the power. However, a QF and a utility were also permitted to negotiate the rates for capacity and energy so long as the result would not exceed the utility's avoided cost.

> 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.

The Commission is aware that PURPA and the FERC's regulations do not proscribe a single methodology for a state to determine the avoided cost to be paid by the public utilities under its jurisdiction. In fact, the approaches followed by the states are many and varied. Some of these approaches include the use of a hypothetical proxy generating facility;[7] the peaker method; the partial displacement method; the fueled rates method; the request for proposals/auction method; and the standard avoided cost rate method.

As indicated earlier in this order, the Commission is persuaded that it is time for another comprehensive examination of PURPA and avoided cost issues. Toward that end, the Commission directs Paul Proudfoot, Director of its Electric Reliability Division, to begin the process of forming a Technical Advisory Committee (TAC) to be composed of the Staff and representatives of electric utilities and electric cooperatives, QFs, small power producers, and distributed generation advocates. Mr. Proudfoot shall use the resources of his division to assemble the names of interested persons willing to voluntarily serve in this capacity. Volunteers shall contact Mr. Proudfoot at their earliest convenience to express their interest in participation in the TAC's activities. The objective of the TAC will be 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. Interested persons may contact Mr. Proudfoot by

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[7] The Commission used this method in establishing a QF rate in its February 19, 1987 order in Case No. U-8562, which was based on the avoided cost of a hypothetical 800 megawatt coal plant.

addressing correspondence to him at the Commission's Lansing offices, 7109 West Saginaw Highway, P.O. Box 30221, Lansing, Michigan 48909.  Participation in the TAC may be limited in order to keep the size of the group manageable and to avoid an overlap of representation.

THEREFORE, IT IS ORDERED that:

A.  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.

B.  The Commission's Executive Secretary is directed to provide all electric utilities and electric cooperatives in this state with an electronic copy of this order.

C.  An electric utility or electric cooperative in this state that has a contract with a qualifying facility shall serve a copy of this order on each qualifying facility from which it purchases either capacity or energy within 10 days of the date of this order.

The Commission reserves jurisdiction and may issue further orders as necessary.

MICHIGAN PUBLIC SERVICE COMMISSION

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John D. Quackenbush, Chairman

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Sally A. Talberg, Commissioner

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Norman J. Saari, Commissioner

By its action of October 27, 2015.

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Mary Jo Kunkle, Executive Secretary

ATTACHMENT A

# COMMISSION BRIEFING: STATUS OF PURPA

## PREPARED BY: MICHIGAN PUBLIC SERVICE COMMISSION STAFF

There is increasing interest in distributed generation in Michigan, primarily combined heat and power and solar. As a result of Michigan meeting the 10% renewable energy standard, utilities are no longer seeking contracts with third party generators. These generators are now turning to the PURPA avoided cost rate as an option for sales.

In March 2014, a 113 page report titled "*PURPA Title II Compliance Manual*" (PURPA Manual) was issued jointly by the American Public Power Association, Edison Electric Institute, NARUC and the National Rural Electric Cooperative Association.[1] This is a comprehensive report prepared by industry experts and provides up-to-date analysis on how utility commissions and electric providers can comply with PURPA.

This briefing contains highlights about PURPA, avoided cost and Michigan's activities.

## PURPA Overview

The Public Utility Regulatory Policies Act of 1978 (PUPRA) was passed as part of the legislation known as the National Energy Policy Act. PURPA was enacted to achieve three primary goals:

> **(1)** to provide for increased conservation of electric energy, increased efficiency in the use of facilities and resources by electric utilities, and equitable retail rates for electric consumers,
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> **(2)** to improve the wholesale distribution of electric energy, the reliability of electric service, the procedures concerning consideration of wholesale rate applications before the Federal Energy Regulatory Commission, the participation of the public in matters before the Commission, and to provide other measures with respect to the regulation of the wholesale sale of electric energy,
>
> **(3)** to provide for the expeditious development of hydroelectric potential at existing small dams to provide needed hydroelectric power,

PURPA established a new class of generators called Qualifying Facilities (QF) to receive special rate and regulatory treatment. There are two types of Qualifying Facilities:

> A **small power production facility**[2] is a generating facility of 80 MW or less whose primary energy source is renewable (hydro, wind or solar), biomass, waste, or geothermal resources. There are some limited exceptions to the 80 MW size limit that apply to certain facilities certified prior to 1995 and designated under section 3(17)(E) of the Federal Power Act (FPA) (16 U.S.C. § 796(17)(E)), which have no size limitation. In order to be considered a qualifying small power

[1] http://www.naruc.org/Publications/PURPA_Title_II_Manual.pdf

[2] See http://www.ferc.gov/industries/electric/gen-info/qual-fac/what-is.asp.

production facility, a facility must meet all of the requirements of 18 C.F.R. §§ 292.203(a), 292.203(c) and 292.204 for size and fuel use, and be certified as a QF pursuant to 18 C.F.R. § 292.207.

A **cogeneration facility**[3] is a generating facility that sequentially produces electricity and another form of useful thermal energy (such as heat or steam) in a way that is more efficient than the separate production of both forms of energy. For example, in addition to the production of electricity, large cogeneration facilities might provide steam for industrial uses in facilities such as paper mills, refineries, or factories, or for HVAC applications in commercial or residential buildings. Smaller cogeneration facilities might provide hot water for domestic heating or other useful applications. In order to be considered a qualifying cogeneration facility, a facility must meet all of the requirements of 18 C.F.R. §§ 292.203(b) and 292.205 for operation, efficiency and use of energy output, and be certified as a QF pursuant to 18 C.F.R. § 292.207. There is no size limitation for qualifying cogeneration facilities.

Qualifying Facilities receive three benefits:

(1) the right to sell energy or capacity to a utility,

(2) the right to interconnect and purchase supplementary power, back-up power, maintenance power, and interruptible power at rates which are just and reasonable, and

(3) relief from certain regulatory burdens (PUCHA, largely exempt from state utility regulatory requirements and Federal Power Act) .

To register as a qualifying facility, a generator must complete and file FERC form 556. Generators with a net generation capacity of 1 MW or less, may self-certify without applying and paying the fees for FERC certification.[4] Generators larger than 1 MW must apply for FERC certification which will be acted upon within 90 days or deemed approved. As part of a filing for FERC certification, generators must provide notice to the state's public utilities commission and the interconnecting utility.

Qualifying facilities generally have the option of selling to a utility either at the utility's **avoided cost** or at a negotiated rate. PURPA also provides the generator an option to sell energy either "as-available" or as part of a legally enforceable obligation for delivery of energy or capacity over a specified term. The phrase "specified term" is not clearly defined; however, an argument can be made that the term should be at least long enough for a generator to be able to obtain financing.

While FERC has also issued regulations on PURPA section 210, as originally implemented, FERC rules require state public service commissions and non-regulated utilities (primarily rural cooperatives and municipalities not regulated by state authority) to set rates for the host utility to purchase power from a

[3] Ibid.

[4] If desired, a generator 1 MW or less may opt for FERC certification instead of self-certification.

qualifying facility. State regulatory commissions and non-regulated utilities, under FERC regulations, also have the responsibility to determine the cost of interconnecting a qualifying facility with the utility system, and to specify the manner and time period in which the qualifying facility will reimburse the utility for this interconnection cost. Also, as originally implemented, FERC rules gave states and nonregulated utilities the responsibility to establish rates for the sale of supplementary, back-up, maintenance, and interruptible power to QFs. State commissions and non-regulated utilities have section 210 implementation plans in accordance with FERC rules.

> Each electric utility is required to have standard offer tariffs for purchases from QFs with design capacity of 100 kW or less. In addition, it is also permissible that standard offer tariffs be available for purchases from QFs of greater than 100 kW. (PURPA Manual p. 10)

<u>Avoided Cost – Standard Offer Rates</u>
PURPA requires states to establish standard offer rates for projects 100 kW and under. In *Reviving PURPA's Purpose*, Carolyn Elefant discusses the standard offer rate:[5]

> The 100 kW size limit is a floor for standard offers, not a ceiling. States have discretion to establish standard rates for QFs larger than 100 kw; for example, California makes a short-term and long-term standard offer contract available to QFs of 20 MW or less; Oregon standard offer contracts are for 10 MW or less; in North Carolina, some standard offers are available to small hydro and waste–to-energy QFs of 5 MW or less. Elefant, page 7[6]

<u>Avoided Cost – Timing</u>
Carolyn Elefant describes "selling energy on an as-available basis" as selling/purchasing at the utility's avoided cost at the time the energy is delivered. However, a QF selling under a contractual obligation would be eligible for avoided cost rates calculated either at the time of delivery or at the time the contractual obligation is incurred.

> When rates are calculated at the time the contractual obligation is incurred, they must be estimated for the duration of the contract. FERC holds that variation of actual avoided costs from the original estimates does not invalidate the originally determined avoided cost price. Elefant, page 7[7]

The PURPA Manual describes that utilities with more than 500 million kWh in retail sales must make avoided cost data available to the state commission at least every two years. Utilities are required to have the following data available for public inspection:

> (1) The estimated avoided cost on the electric utility's system, solely with respect to the energy component, for various levels of purchases from qualifying

[5] See http://www.lawofficesofcarolynelefant.com/fercfights/wp-content/uploads/2011/10/Elefant_Reviving_PURPA_Avoided_Costs_2011.pdf
[6] ibid
[7] ibid

facilities. The levels of purchases must be stated in blocks of not more than 100 MW for systems with peak demand of 1,000 MW or more, and in blocks equivalent to not more than 10 percent of the system peak demand for systems of less than 1,000 MW. The avoided costs must 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 for each of the next 5 years;

(2) 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; and

(3) 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 must be expressed in terms of individual generating units and individual planned firm purchases.

Energy Policy Act of 1992 (EPAct)[8]

The Energy Policy Act of 1992 (P.L. 102-486) (EPACT) required the state commissions to consider whether adoption of certain standards would carry out the purposes of the Public Utility Regulatory Policies Act of 1978 (PURPA). A new category of generators was created under EPACT called Exempt Wholesale Generators (EWG). These generators are Wholesale generators that are exempt from certain financial and legal restrictions stipulated in the Public Utilities Holding Company Act of 1935. EWGs can generate electricity for sale at wholesale and request the FERC to order a utility to transmit its power at wholesale to another utility.

Energy Policy Act of 2005 (EPAct 2005)

The EPAct 2005 allows utilities to terminate mandatory purchase obligation if qualifying facilities have non-discriminatory access to competitive markets.

DTE Electric was relieved, on a service territory-wide basis, of the mandatory purchase obligation requirement to enter into new purchase obligations for generators with a net capacity greater than 20 MW effective October 26, 2009.[9] FERC granted a similar request to Consumers effective January 25, 2012.[10]

[8] Information in this section is summarized from the following NRRI report: Burns & Eifert, *A WHITE PAPER ON THE ENERGY POLICY ACT OF 1992: AN OVERVIEW FOR STATE COMMISSIONS OF NEW PURPA STATUTORY STANDARDS***,** April 1993, http://communities.nrri.org/home?p_auth=h1X6Qnbt&p_p_auth=7ze1UKn3&p_p_id=20&p_p_lifecycle=1&p_p_state=exclusive&p_p_mode=view&_20_struts_action=%2Fdocument_library%2Fget_file&_20_groupId=317330&_20_folderId=0&_20_name=5422

[9] https://www.ferc.gov/whats-new/comm-meet/2010/041510/E-12.pdf

[10] http://www.ferc.gov/EventCalendar/Files/20120424160511-QM12-3-000.pdf

Prior to the enactment of EPAct 2005, no more than 50 percent of a QF could be owned by an electric utility. That ownership requirement was eliminated and now electric utilities can have 100 percent ownership in QFs.

## MPSC PURPA &Avoided Cost History

On March 17, 1981, the Commission ordered the initiation of proceedings in Case No. U-6798 to implement the provisions set forth in Title II, Section 210 of PURPA.

FERC required that by March 20, 1981 all state utility regulatory authorities commence implementation of Title II, Section 210 of PURPA. In doing so FERC obligated the regulatory bodies to:

1. File a report with FERC by March 20, 1981 describing the manner in which they were to implement the regulations.
2. Set rates for new capacity (build starting on or after November 9, 1978) purchases from QFs.
3. Establish standard rates based on avoided cost for each utility.
4. Establish just, reasonable, and nondiscriminatory rates for old capacity which provided sufficient incentive. This did not have to be based on avoided cost.
5. Establish just, reasonable, in the public interest and nondiscriminatory rates for stand-by service to QFs.
6. Establish and determine interconnection costs and methods of payment.
7. Formulate procedures for handling complaints.

In the above-mentioned order, the Commission expressed interest in the development of polices to promote conservation activities and the use of alternative energy in the State.

The order stated that within 90 days, utilities were to remove any tariff prohibitions on selling stand-by energy to or purchasing energy or capacity from, or operating in parallel with QFs.

It also required rates for utility purchases to be equal to fuel and purchase power base plus the monthly purchased power and fuel adjustment clause in effect at the time of purchase. The utility could charge a monthly metering and billing fee not greater than the residential service charge.

The above order required all utilities with sales exceeding 500 million kWh a year (Consumers Power Company, Detroit Edison Company, Indiana Michigan Electric Company, Lake Superior District Power Company, Michigan Power Company, Upper Pennisula Power Company, Wisconsin Electric Power Company, and Wisconsin Public Service Corporation) to file within 150 days of the order that included, at a minimum, responses to the following:

1. How should avoided cost be defined for energy and capacity?
2. Methods to calculate estimates of avoided costs for energy and capacity.
3. How to derive utility purchases from QFs be derived from avoided cost estimates.

4. Methods for utility purchases from old capacity QFs.
5. How to design stand-by rates for QFs.
6. Conditions QFs should meet for interconnection.
7. Criteria the Commission should use to declare a “system emergency” as defined in Section 210.
8. Projections of energy and capacity expected from QFs.
9. Circumstances that simultaneous operation is cost justified.
10. Dispute resolution methods.
11. Rate design differences for cogenerators and small power producers.
12. Should the Commission promulgate safety and reliability standards for QFs?
13. What innovations could help to remove existing barriers?
14. Any other issues.

On August 27, 1982, the Commission issued a final order in Docket No. U-6798. This ordered approved various settlement agreements and approved tariffs allowing for the implementation of Section 210 of PURPA. In the settlement agreements, Consumers Power Company and Detroit Edison Company both agreed to base combined energy and capacity payments on the next generation unit to be added to the utility’s system (excluding units that were under construction at the time). At the time this was to be a coal generating facility. There were also provisions for energy only contracts that would be based on “auxiliary power provision” of Consumer Power Company’s residential and commercial rate and for Detroit Edison’s energy only payment, it would be the time-of-day incremental cost of energy. Net metering was also under consideration during these proceedings, but at that time net-metering was a new concept and the Commission did not require adoption of the practice, but ordered Staff to continue exploring the issue. Alternatively, the Wisconsin PSC required its utilities to adopt net-metering.

Staff supported, and the Commission agreed, that joint ventures between utilities and power producers would provide opportunities not otherwise available. This would allow the utility to form a non-jurisdictional subsidiary.

Additionally, the Commission established a Technical Advisory Committee (TAC) composed of utility, small power producer and cogenerator (SPP&C) representatives. The purpose of the TAC was to investigate the safety, reliability and installation criteria for interconnection of PURPA QFs. The TAC submitted a report on October 29, 1985 titled, “Guidelines on Interconnection for SPP&Cs”. The report discussed the following:

1. Personnel Safety
2. Improving equipment and system protection and reliability
3. Maintaining or improving electric service quality
4. Facilitate communication between QFs and utilities
5. Clarify utility policies and procedures

On January 22, 1986 the Commission filed an order requiring all utilities under the Commission’s jurisdiction to review the report filed by the TAC and adopt the recommendations if deemed appropriate. The Commission required that by April 1, 1986 each utility was to file a report addressing the specific measures it took to address the findings of the report. It also required Staff to further investigate issues raised during the process that were outside of the scope of the TAC (insurance needs, prices for kVAR support, impact of SPP&C introduced harmonics on lines and benefits to SPP&C from the utilities frequency and voltage regulation). The order disbanded the TAC.

## Utility Avoided Cost Notification to Commission

As a result of Case No. U-6798, information has been filed with the Act 304 Section by some utilities with regard to avoided cost. Four utilities have information filed with the Commission: Consumers Energy, DTE Electric, UPPCO, and WPS. Of these utilities, UPPCO and WPS have filed the names of people who contacted them for more information regarding PURPA. They provided no avoided cost rate. The last time UPPCO and WPS filed a letter in this regard was January 2008.

Consumers Energy filed their last letter with the Commission on October 4, 2011. The letter contained the energy-only purchase price to be paid for the purchase of energy from qualifying generating installations of 100 kW or less. The price for on-peak hours was $0.0489/kWh and the price for off-peak hours was $0.0319/kWh. The company stopped filing these letters because its belief was that the locational marginal price (LMP) was a reasonable proxy for the values they were providing the Commission.

DTE Electric continues to file letters. The most recent letter was filed on May 22, 2015 providing details for April 2015. The following six values were provided:

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|---|---|
| Maximum Marginal Cost on-Peak | 3.4100 ¢/kwh |
| Maximum Marginal Cost Off-Peak | 3.7300 ¢/kwh |
| Minimum Marginal Cost On-Peak | 1.9390 ¢/kwh |
| Minimum Marginal Cost Off-Peak | 1.7770 ¢/kwh |
| Average Marginal Cost On-Peak | 2.3153 ¢/kwh |
| Average Marginal Cost Off-Peak | 2.2072 ¢/kwh |

With the exception of a 6 month gap in 2012, it appears DTE Electric has continued to provide this data since 2005.

Current PURPA Tariffs

The PURPA payment provisions are provided below:

Consumers Energy:
Rates GSG-1 & GSG-2
**Sales of Energy to the Company:**
**Administrative Cost Charge:**
Generation installation with a capacity of over *550* kW but less than or equal to 2,000 kW
As negotiated or $0.0010 per kWh purchased, at the option of the customer
Generation installation with a capacity of over 2,000 kW
As negotiated

**Energy Purchase:**
An energy purchase by the Company shall be bought at the Midwest Independent Transmission System Operator's (MISO) real-time Locational Marginal Price (LMP) for the Company's load node (designated as "CONS.CETR" as of the date of this Rate Schedule) less $0.005/kWh.

<u>DTE</u>
Standard Rider No. 5 Cogeneration
Standard Rider No. 6 Small Power Producing Facilities

B. Sales by the Customer to the Company:
1. New Facilities:

a. Energy Sales: The rate will be based on the forecasted average incremental cost of energy. The rates will recognize time-of-day price variations based on a weekly forecast.

b. Capacity and Energy Sales: The rate will be based on the combined capacity and energy costs of the Belle River Power Plant, adjusted to reflect the effects of inflation between the in-service date of the cogeneration facility and the in-service date of the Belle River Power Plant. This rate, so determined, will be adjusted to be reflective of the forecasted capacity factor, availability, operating schedule and the ability of the Company to dispatch the said cogeneration unit. The rate so determined will apply to facilities with a capacity of 100 kW or less. The rate for facilities having a capacity of over 100 kW will be made under negotiated agreement.

A one mill per kilowatthour charge shall be assessed to all customers on this rate to offset the Company's additional administrative expenses associated with these transactions.

## <u>What is Avoided Cost?</u>

PURPA (C.F.R. § 292.101(b)(6) ) defines "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.

| Factors That may be Considered In Determining Avoided Cost<br>FERC Rules: (18 C.F.R.§292.304(d)) |
|---|
| 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<br>http://www.narucmeetings.org/Presentations/25%20PURPA%20Avoided%20Cost%20Calculation%20Differences%20Across%20States-Carolyn%20Elefant.pdf |

| 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<br>http://www.narucmeetings.org/Presentations/25%20PURPA%20Avoided%20Cost%20Calculation%20Differences%20Across%20States-Carolyn%20Elefant.pdf |

The above FERC-accepted methods for determining avoided cost can result in a wide range of avoided costs. In an August 2011 report, *Reviving PURPA's Purpose*, Carolyn Elefant describes considerations for determining an avoided cost methodology:[11]

> The economic rationale for PURPA is to address market power disparity between independent power producers and utilities.
>
> ***
>
> If the development of alternative resources could occur at a lower cost than the utility's self-built generation, then the lost opportunity to obtain those cost savings puts customer interests in lower costs at odds with the utility's interest in building generation assets on which it is entitled to earn a rate of return. For example, excessively low rates may discourage industrial customers from investing in combined heat and power units to meet their needs for both steam and electricity. They may instead utilize less-efficient boilers for steam and purchase electricity from the utility.
>
> The policy challenge to promote customer interests in a monopoly utility market (as well as in some partially-deregulated markets) is to find the "sweet spot" where rates are set high enough so as not to be penny-wise and pound foolish. Elefant, pages 4 - 5[12]

MPSC Staff's estimation of the approximate avoided cost rate under the proxy unit and market based pricing methodologies is provided below.

Proxy Unit Methodology

One option for avoided cost is the proxy plant method. For purposes of developing transfer prices for 2008 PA 295 cost recovery, Staff developed the Staff Transfer Price Schedule that utilizes 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 and projections for materials and labor costs. An NGCC plant is utilized as it is assumed to be the most logical marginal plant to be built. Since the PURPA facilities would be offsetting the need for new capacity, it could be argued that they should be compensated at this rate. Below is the most recent transfer price schedule based on an NCGG proxy plant methodology.

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[11] See http://www.lawofficesofcarolynelefant.com/fercfights/wp-content/uploads/2011/10/Elefant_Reviving_PURPA_Avoided_Costs_2011.pdf

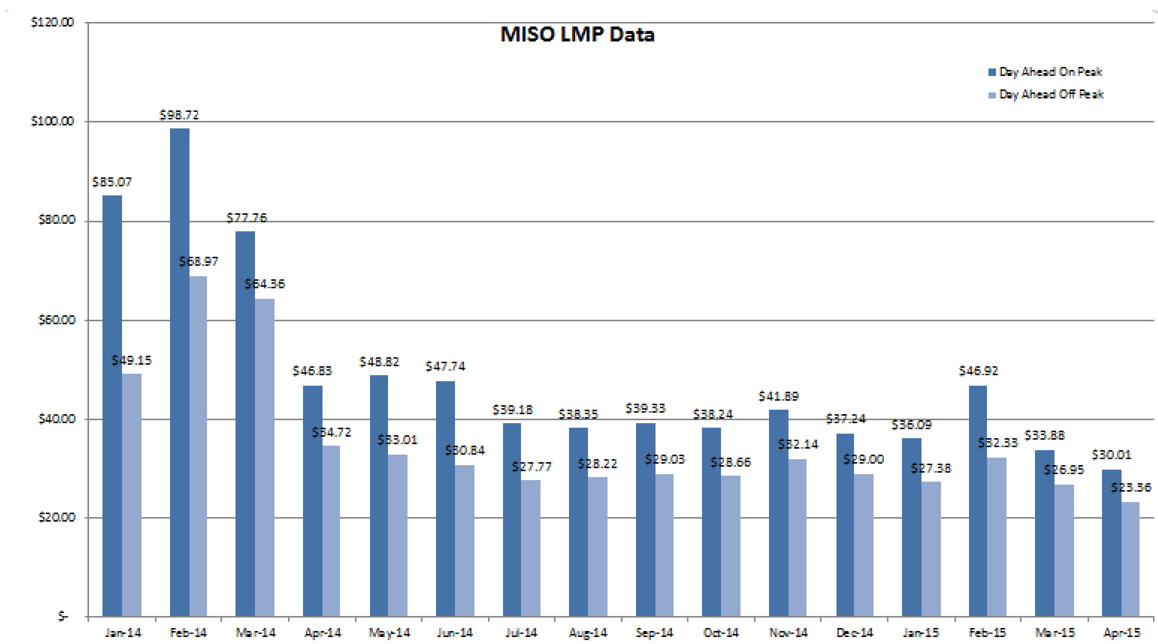
[12] See http://www.lawofficesofcarolynelefant.com/fercfights/wp-content/uploads/2011/10/Elefant_Reviving_PURPA_Avoided_Costs_2011.pdf

| | 2015 Transfer Price Schedule ($/MWh) |
|---|---|
| 2015 | $68.27 |
| 2016 | $69.40 |
| 2017 | $72.52 |
| 2018 | $75.07 |
| 2019 | $77.44 |
| 2020 | $79.37 |
| 2021 | $80.50 |
| 2022 | $81.64 |
| 2023 | $83.50 |
| 2024 | $84.72 |
| 2025 | $86.71 |
| 2026 | $88.28 |
| 2027 | $90.02 |
| 2028 | $92.68 |
| 2029 | $94.55 |

<u>Market Based Pricing Methodology</u>

This methodology values the QF's energy at the MISO LMP and capacity at either the MISO Planning Reserve or Utility Zonal Resource Credit Auctions. This appears to be the method currently preferred by Consumers Energy and DTE and results in a total payment between 3 and 4 cents per kWh to QFs. This avoided cost is too low to result in new distributed generation projects. The monthly MISO LMP prices are shown below.

Market Energy Pricing:



Market Capacity Pricing:

| Market Capacity Value Description | Capacity Value $ per MW-Year | Capacity Value Spread Over Expected Annual Solar Generation $ per kWh |
|---|---|---|
| MISO Planning Reserve Auction | $13,213 | 0.005 |
| Consumers Energy’s Zonal Resource Credit Reverse Auction Results | $30,000 | 0.011 |
| Estimated MISO Load Carrying Capability of Solar: 0.45<br>Annual Solar Generation per MW in MWh (DC installed): 1226 MWh<br>Solar Capacity Factor: 0.14 | | |

For the month of April 2015, the on peak LMP ($30 per MWh) plus the range of capacity pricing options ($5 - $11 per MWh) results in a total avoided cost payment of $35 - $41 per MWh.

## 2015 MPSC Staff Avoided Cost Activities

There is increasing interest in distributed generation development. The Commission May 14, 2015 Order in Case No. U-17752 approving Consumers Energy’s community solar program, describes a scenario for third party community solar based on the project developer obtaining a PURPA contract the utility. Additionally, the Commission tasked Staff with reinstating the Solar Working Group to investigate capacity pricing for solar. Staff foresees this task to have an impact on the capacity component for purposes of developing Companies’ avoided cost.

On March 4, 2015 MPSC Staff met to discuss the current status of the MPSC’s PURPA rate. The general consensus was that a formal avoided cost rate with both energy and capacity components had not been established since at least the early 1980s. The MISO LMP is considered a *de facto* energy-only avoided cost rate.

MPSC Staff, Consumers Energy and DTE held an initial meeting on April 2, 2015. Consumers Energy is actively working with several generators because PURPA contracts are expiring or due for renegotiation. DTE does not have a PURPA contract due to expire until 2023.

Subsequent meetings were held with Consumers Energy and DTE on May 27, September 17, and October 14. MPSC Staff met with a group of qualifying facilities on August 19.