Michigan Public Service Commission

Report on the Implementation Of The Public Utility Regulatory Policies Act of 1978 (PURPA)

April 20, 2020

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LICENSING AND REGULATORY AFFAIRS

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Executive Summary

Public Act 341 of 2016 (Act 341) amended Public Act 3 of 1939 and became effective on April 20, 2017. Act 341 included new requirements for the Michigan Public Service Commission (Commission) to implement title II, section 210 of the federal Public Utility Regulatory Policies Act of 1978 (PURPA). Within one year of the effective date of PA 341, and every two years thereafter, the Commission is mandated to issue a report providing "a description and status of qualifying facilities in this state, the current status of power purchase agreements of each qualifying facility, and the commission's efforts to comply with the requirements of PURPA."[1] This report describes Commission proceedings, as well as utility activities related to the implementation of this 1978 federal law.

Under PURPA, small power production facilities and cogeneration facilities, known as qualifying facilities (QFs), have a right to interconnect with and sell power to the local utility. Michigan has seen considerable growth in the number of QFs that have projects, or are planning projects, with investor-owned utilities. For this report, the Commission obtained from utilities the most current information about these QFs. A comprehensive discussion of Michigan QFs is included in this report.

The Commission has continued to work diligently to ensure that Michigan is properly implementing PURPA. The PURPA case proceedings detailed in this report have spanned several years. A summary of the most recent QF contracts is included in **Appendix A**. An avoided cost fact sheet summarizing current avoided cost information for each investor-owned utility is provided in **Appendix B**.

The Commission is also closely monitoring proposed changes to PURPA at the federal level. A brief summary of PURPA reforms proposed by the Federal Energy Regulatory Commission (FERC) is included in this report. As PURPA reform develops, the Commission will continue to ensure that Michigan fully complies with the requirements of federal law and rules.

[1] MCL 460.6v(5)

Introduction

Report Criteria

On April 20, 2017, Public Act 341 of 2016 (PA 341) became effective. Section 6v outlines new requirements for the Commission to implement title II, section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA), a federal law. PA 341 requires that the Commission conduct a proceeding at least every five years to ensure that procedures and rate schedules, including avoided cost rates, are just and reasonable based on PURPA and Federal Energy Regulatory Commission (FERC) regulations and orders implementing PURPA. Within one year of the effective date of PA 341, and every two years thereafter, the Commission shall issue a report describing the status of qualifying facilities (QFs) in the state, the current status of power purchase agreements (PPAs) for each QF, and the Commission's efforts to comply with the requirements of PURPA. This is the Commission's second report to the state legislature regarding PURPA in Michigan.

Public Utility Regulatory Policies Act of 1978

In 1978, Congress passed and President Carter signed the Public Utility Regulatory Policies Act, commonly referred to as PURPA. The main purpose of the act was to encourage the development of renewable electric energy and cogeneration resources without adversely affecting the retail rates of electric utilities. PURPA requires that electric utilities interconnect with a QF (provided the QF pays reasonable interconnection costs), purchase energy and capacity at the utility's avoided cost, and sell supplemental, backup, maintenance, and interruptible power (standby service) to the QF on a non-discriminatory basis.[2]

PURPA's "must purchase" obligation applies to all energy and capacity made available for sale and applies to all utilities. State utility commissions and non-regulated utilities have the responsibility to determine interconnection costs, establish avoided costs, and set rates for standby service.

Michigan PURPA History

In 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 in Case No. U-6798. In the Initial Order, the Commission identified the following state regulatory authority obligations under PURPA and the federal regulations implementing it:

1. File a report with FERC describing implementation
2. Set avoided cost rates

[2] 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. CFR §292.101(6).

3. Set a standard rate for QFs of 100 kW or less
4. Set rates for standby service
5. Address interconnection costs
6. Establish a procedure for handling complaints

The utility obligations are described below:

1. Purchase at avoided cost
2. Provide standby service
3. Provide interconnections to QF
4. 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. This 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 avoided cost determination involved a PURPA contract between the Midland Cogeneration Venture (MCV) 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.

On June 10, 2008, the Commission issued an order in another significant case involving MCV and Consumers Energy, Case No. U-15320. This order reduced the capacity payment from the 3.62 cents per kilowatt-hour (kWh) that the Commission had previously approved for cost recovery to 1.014 cents per kWh.[3] Also included in this order, was a provision to change the variable energy payment from a coal-based payment to a natural gas-based payment.

Several legislative acts were passed in Michigan related to PURPA. Act 81 of 1987 (MCL 460.6j, as amended) was enacted to address capacity payments for PURPA contracts, as well as other issues. Act 2 of 1989 (MCL 460.6o, as amended) was enacted to address utility purchases from certain landfill gas and solid waste QFs. The Energy Policy Act of 2005 (PL 109-58; 119 Stat 594) allowed

[3] https://mi-psc.force.com/s/filing/a00t0000005pfgwAAA/u153200078

utilities to terminate mandatory purchase obligations if QFs have non-discriminatory access to competitive markets.

A number of PURPA contracts were executed and approved by the Commission during this time period. A list of recently approved PURPA contracts is included in **Appendix A**.

Status of Qualifying Facilities

When PURPA was implemented in 1978, a new class of generating facilities was established. This new class, known as qualifying facilities, would receive special rate and regulatory treatment. FERC has two categories for QFs: qualifying small power production facilities, and qualifying cogeneration facilities. A small power production facility generates 80 MW or less. Its primary energy source is renewable (hydro, wind or solar), biomass, waste, or geothermal resources. A cogeneration facility 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. Generation facilities must meet FERC requirements in order to be designated as QFs.[4] Changes to PURPA in 2005 require FERC to excuse utilities upon request from the mandatory purchase obligation if the QF has non-discriminatory access to a wholesale electricity market such as MISO or PJM. There is a rebuttable presumption that QFs larger than 20 MW meet this requirement. Both Consumers Energy and DTE Electric have requested and received relief from FERC regarding the mandatory purchase obligation from QFs larger than 20 MW.[5]

Michigan QFs

In order to have current, accurate data for this report, Commission staff issued a survey request to investor-owned utilities in Michigan. The survey asked for information on qualifying facilities. Specifically, each utility was asked to provide for each QF: name, technology type, nameplate capacity, contract termination date, and type of contract. Information about storage ability and capacity for each QF was also included in the survey for this year, although none of the utilities reported any storage being utilized. The survey request excludes any net-metered facilities. QF survey results include projects used for renewable portfolio standards (RPS) compliance, as well as projects with Commission-approved PPAs that are under development or are not yet generating.

This report covers seven investor-owned electric utilities in Michigan: Alpena Power Company (Alpena), Consumers Energy (CE), DTE Electric (DTE), Indiana Michigan Power (I&M), Northern States Power-Wisconsin NSP-W), Upper Peninsula Power Company (UPPCO), and Upper Michigan

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[4] https://www.ferc.gov/industries/electric/gen-info/qual-fac.asp

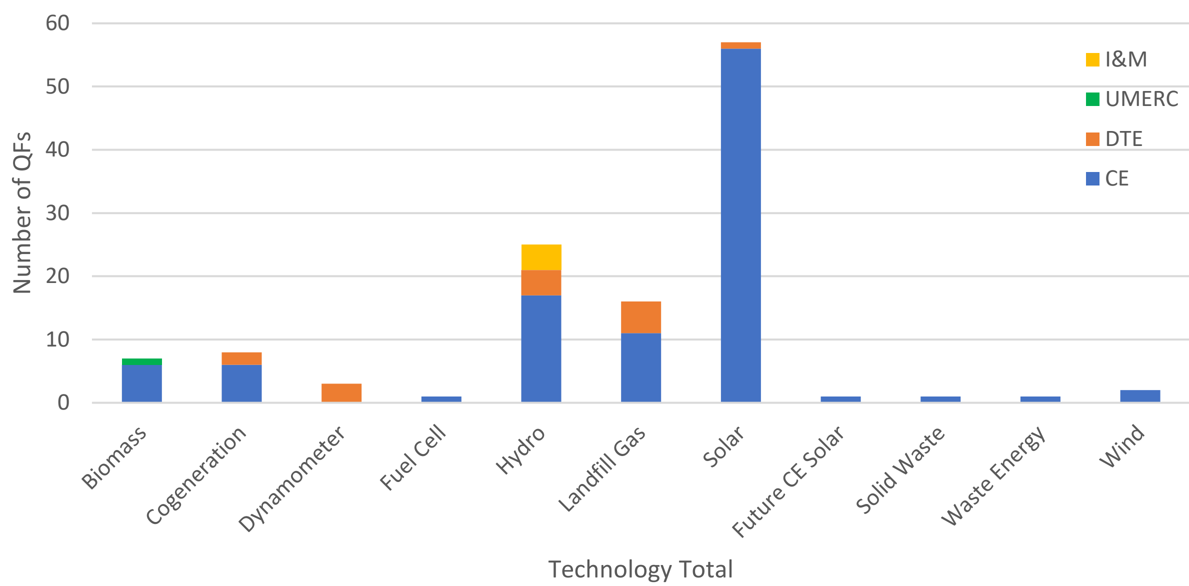
[5] DTE Electric https://www.ferc.gov/whats-new/comm-meet/2010/041510/E-12.pdf
and Consumers Energyhttps://www.ferc.gov/EventCalendar/Files/20120424160511-QM12-3-000.pdf

Energy Resources Corporation (UMERC). While Alpena, NSP-W, and UPPCO did not report any QFs located in Michigan, the remaining four utilities reported having at least one QF.

The two largest investor-owned utilities in Michigan, CE and DTE, reported 103 and 15 QFs, respectively.[6] The QFs included in CE's survey number include both existing QFs and 57 new solar QFs with PPAs approved on December 6 and 19, 2019 and April 15, 2020. These new QFs are under development and are not yet generating. Detailed QF information provided by both companies is summarized in detail below. UMERC has one biomass-fueled QF with a nameplate capacity of 56 MW. I&M has four hydroelectric QFs in its Michigan territory with total nameplate capacity of 1.35 MW. Data on QFs participating in the Distributed Generation Program is presented each year in the Commission's annual Distributed Generation Report.[7]

Figures 1 and 2, below, provide a summary of QF contracts by technology type for investor-owned utilities in Michigan. These figures include projects in service and under development with Commission-approved PPAs; however, the Future Solar category (depicted as one QF contract) represents 20 MW of new solar QFs where CE is finalizing contract negotiations with an unspecified number of solar QFs.

Figure 1: Investor-owned Utility QFs by Technology Type, 123 Total QF Contracts



Source: MPSC QF Survey Data Provided by Utilities, February 2020

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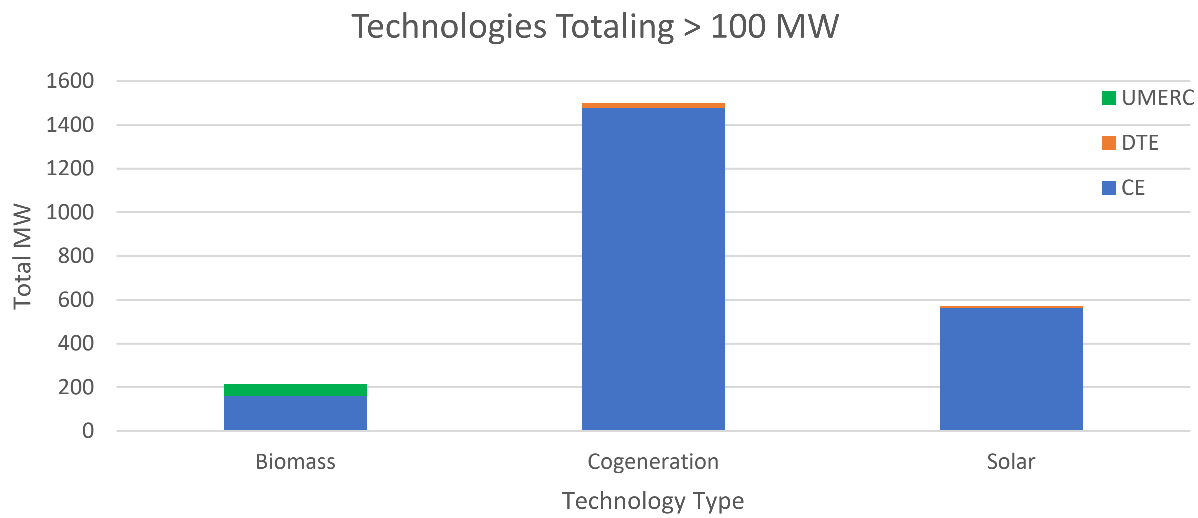
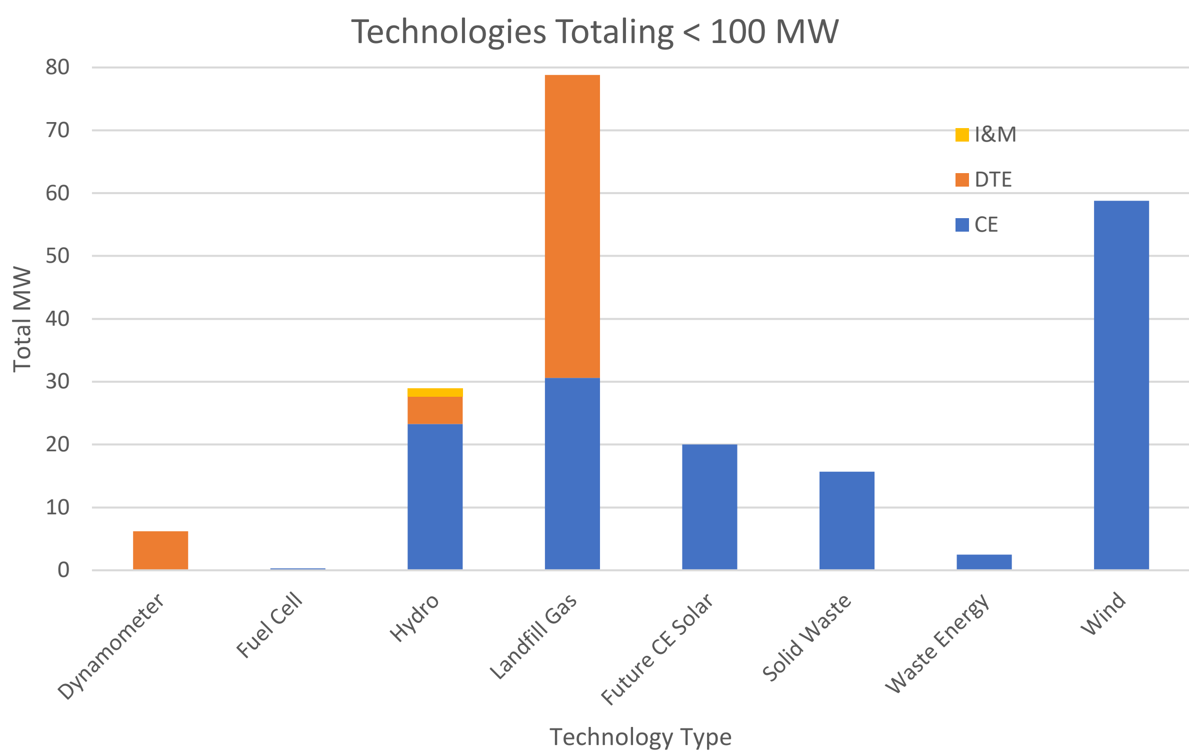
[6] Previous report data included third-party renewable portfolio standard and voluntary green pricing facilities. This report reflects PURPA QFs only.
[7] https://www.michigan.gov/documents/mpsc/DG_and_LNM_Report_Calendar_Year_2018_final_673202_7.pdf

Figure 2: Investor-owned Utility QF Nameplate Electric Generating Capacity by Technology Type, 2,498 MW Total

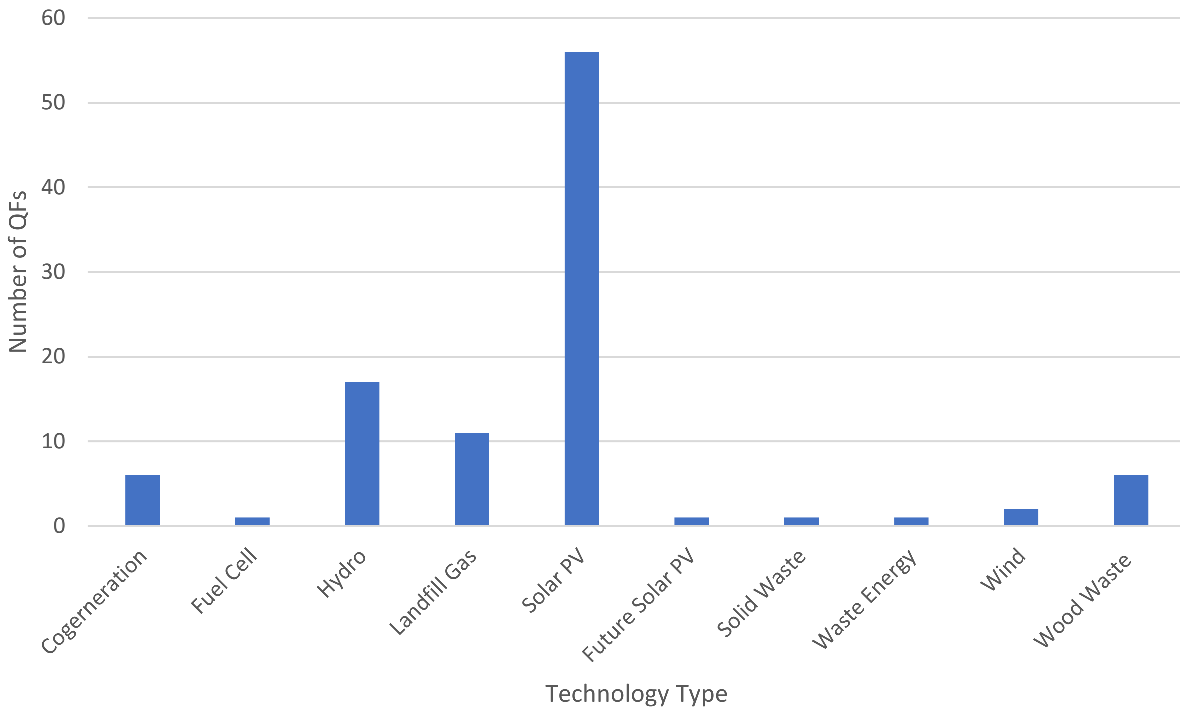




Source: MPSC QF Survey Data Provided by Utilities, February 2020

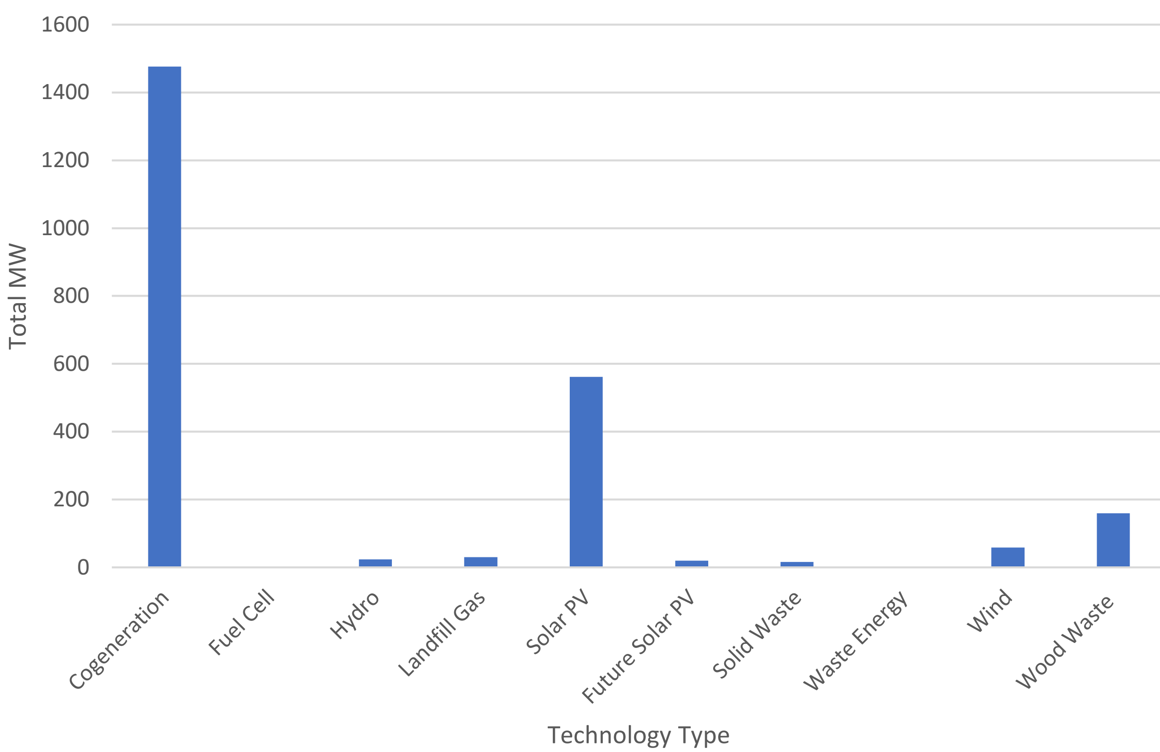
CE has 103 QF facilities under contract within its territory. Figure 3, below, summarizes CE's qualifying facilities by technology type. These 103 QFs have a total of 2,350 MW of nameplate capacity under contract (excluding net-metering capacity). Figure 4, also below, summarizes this nameplate capacity by technology type. These figures include projects in-service and under development.

Figure 3: CE QFs by Technology Type, 103 Total QF Contracts



Source: MPSC QF Survey Data Provided by Utilities, February 2020

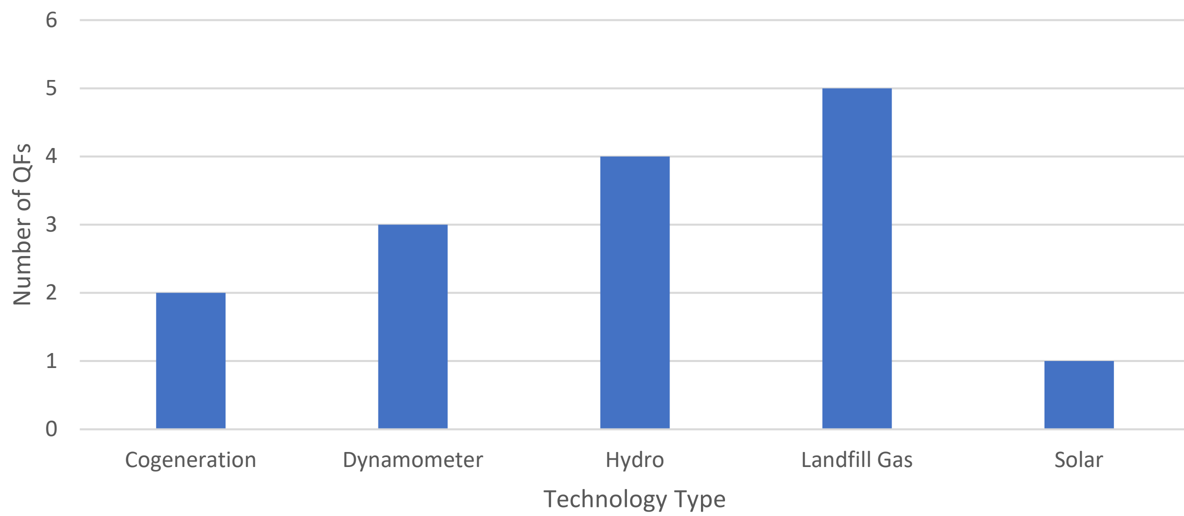
Figure 4: CE QF Nameplate Capacity by Technology Type, 2,350 MW Total



Source: MPSC QF Survey Data Provided by Utilities, February 2020

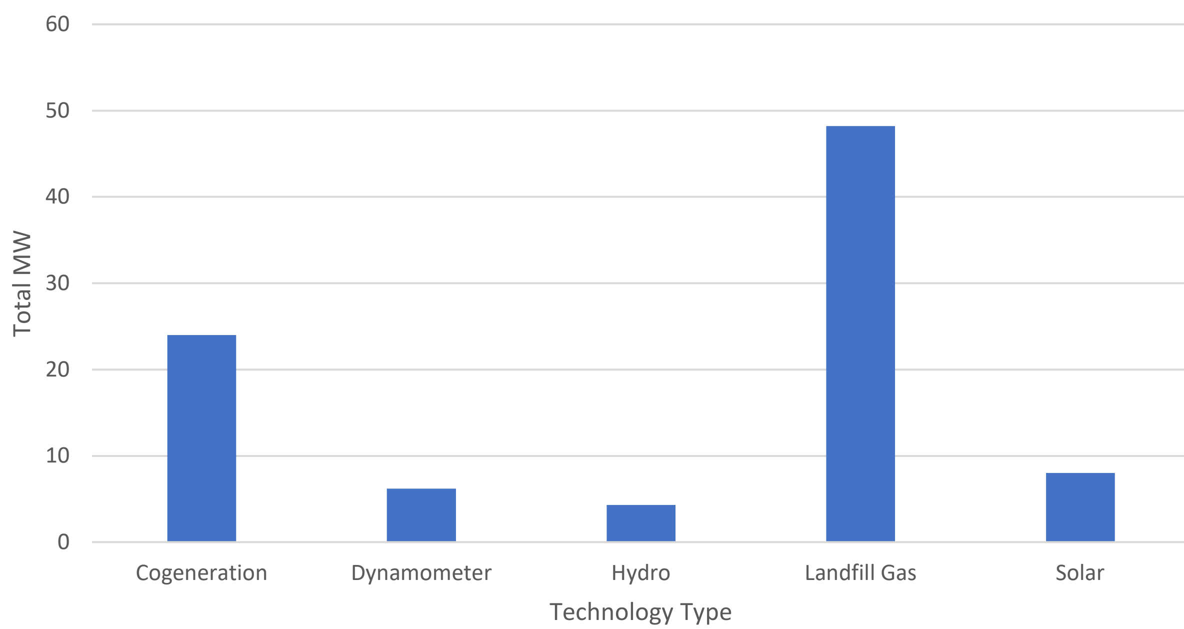
DTE has 15 QF facilities within its service territory. Figure 5, below, summarizes DTE's qualifying facilities by technology type. There is a total of 91 MW of nameplate capacity from those 15 facilities. Figure 6, also below, summarizes this nameplate capacity by technology type. These figures include projects in-service because DTE does not have any new QFs with projects under development.

Figure 5: DTE QFs by Technology Type, 15 Total QF Contracts



Source: MPSC QF Survey Data Provided by Utilities, February 2020

Figure 6: DTE QF Nameplate Capacity by Technology Type, 91 MW Total

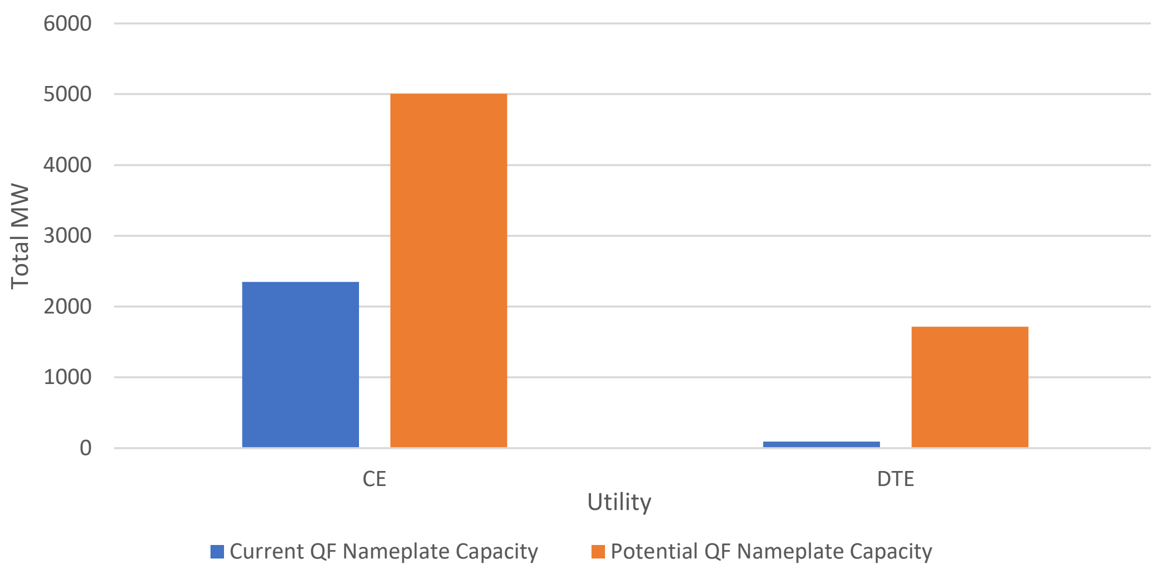


Source: MPSC QF Survey Data Provided by Utilities, February 2020

Potential QFs

The Commission has been updating utilities' avoided cost rates for payment to existing (upon contract expiration, as applicable) and any new QFs.[8] Considering the activity surrounding PURPA, CE and DTE have continued to experience an increase in the number of applications for interconnection and requests for PURPA contracts. As of February 2020, CE reported pending interconnection applications totaling 5,008 MW.[9] As of February 2020, DTE reported applications totaling 1,716 MW. While not all pending interconnection projects are QFs and some are likely to drop out for various reasons (interconnection costs, site control and permitting issues, etc.), the amount of pending interconnection applications indicates significant growth in QF development activity. The projects are primarily solar. For the purposes of this report, CE's and DTE's pending interconnection applications are considered "potential" QFs. Figure 7, below, illustrates a comparison between the existing and potential nameplate capacity of QFs for both CE and DTE. These figures include projects in service and under development.

Figure 7: Comparison of Existing and Potential QF Nameplate Capacity



Source: MPSC QF Survey Data Provided by Utilities, February 2020

[8] For background on ongoing Commission proceedings and initial decisions, see the MPSC's PURPA Issue Brief available at: http://www.michigan.gov/documents/mpsc/MPSC_Issue_Brief_--_PURPA_606768_7.pdf

[9] There may be overlap between the MW of potential QFs in CE's interconnection queue and the 584 MW of new solar QFs resulting from the settlement in U-20615.

Status of Power Purchase Agreements

A power purchase agreement (PPA) is an agreement between a utility and a QF for the sale of energy, capacity, or both. PURPA requires utilities to make a Standard Offer rate available to QFs. The Standard Offer is a tariffed rate paid to QFs through a standard contract with the utility. By law, the Standard Offer must be available to QFs 100 kW and smaller. However, it may be made available to larger QFs. At the time PURPA was first implemented in the early 1980s, the Standard Offer tariff was limited to QFs 100 kW and smaller, which is small enough that an accompanying Standard Offer PPA was most likely not needed and the terms and conditions of service could be included in the Standard Offer tariff.

Michigan QF PPAs

As CE and DTE have nearly all of the QF PPAs in Michigan, the report focuses on the status of their contracts. CE has power purchase agreements with each of its 103 QFs. Some of these contracts may contribute to CE achieving its renewable energy goal for the state of Michigan. Section 35 of 2008 PA 295 allows utility ownership of four out of five renewable energy credits unless the PPA specifies otherwise. CE's most recently approved Standard Offer contract and the PPA used for the PURPA settlement in MPSC Case No. U-20165 do not transfer renewable energy credits to the utility.

During 2019 and 2020, CE had a significant increase in the number of executed PURPA QF PPAs. The surge was the result of a September 11, 2019 Commission Order in Case No. U-20615 that approved a settlement agreement.[10] In this order, CE agreed to award 170 MW to PURPA QFs 20 MW or smaller that were in CE's interconnection queue as of a chosen cutoff date. CE also agreed to award 414 additional MW to PURPA QFs 20 MW or smaller that were in CE's interconnection que as of a second chosen cutoff date. A summary of CE's progress toward executing the PURPA PPAs awarded in the U-20615 settlement agreement can be viewed in **Appendix A**.

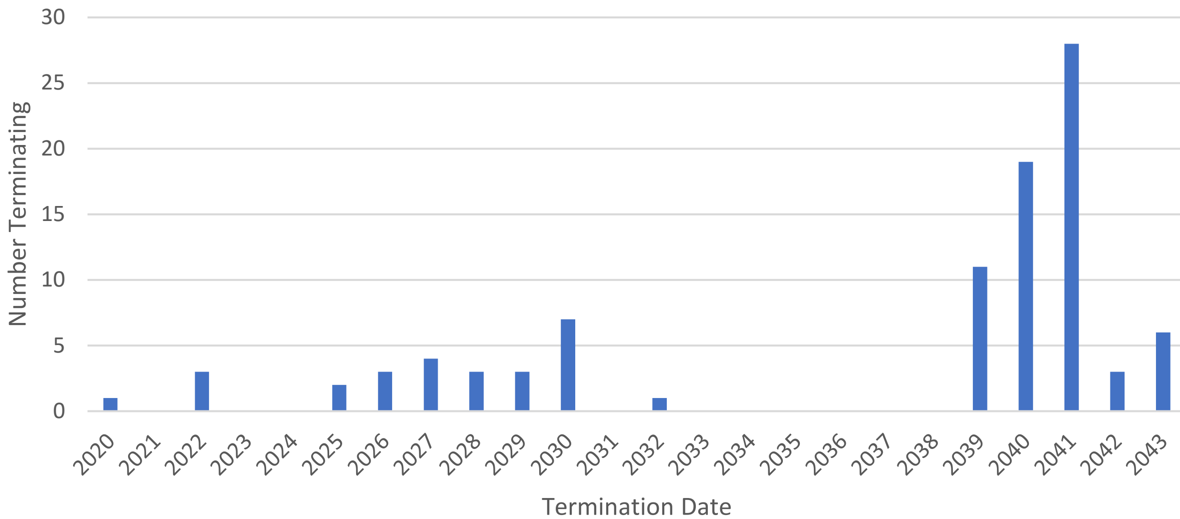
DTE currently has 15 PURPA PPAs. For the other investor-owned utilities in Michigan, UMERC has one QF with a customer generating system (CGS) large tariff PPA. I&M has four QFs with hydro PPAs. Alpena, NSP-W, and UPPCO did not report any PPAs with QFs in Michigan.

Many of the current PPAs are long-term contracts. CE has six long-term PPAs that will expire in the next five years. Many of the other CE PPAs have terms that will not end until the 2030s. The newly executed PURPA PPAs have twenty-year contracts and will not expire until the 2040s. DTE has six evergreen PPAs and fewer long-term PPAs with the first expiration date in 2027. UMERC has one PPA that will retain tariff service until cancelled. I&M has four PPAs that are on-going with six month's written notice to the other party of the intention to discontinue service under the terms of the contract. Figure 8, below, shows contract termination dates for CE PPAs. This figure

[10] https://mi-psc.force.com/s/filing/a00t000000DVPDaAAP/u206150004

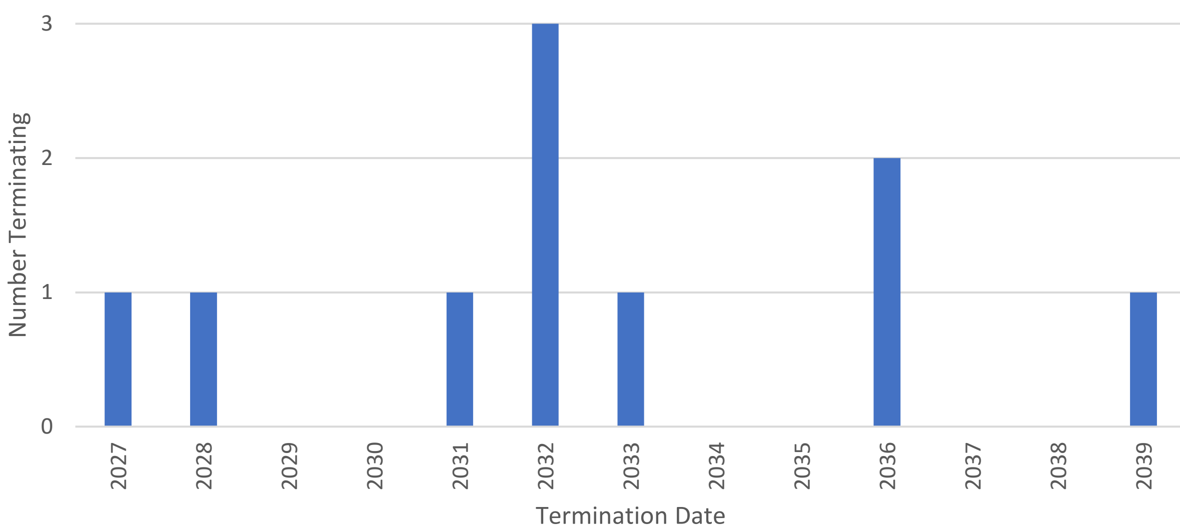
includes projects in service and under development. Figure 9, also below, shows contract termination dates for DTE PPAs. This figure includes projects in service because DTE does not have any new QFs with projects under development.

Figure 8: CE QF Contract Termination Dates[11]



Source: MPSC QF Survey Data Provided by Utilities, February 2020

Figure 9: DTE QF Contract Termination Dates[12]

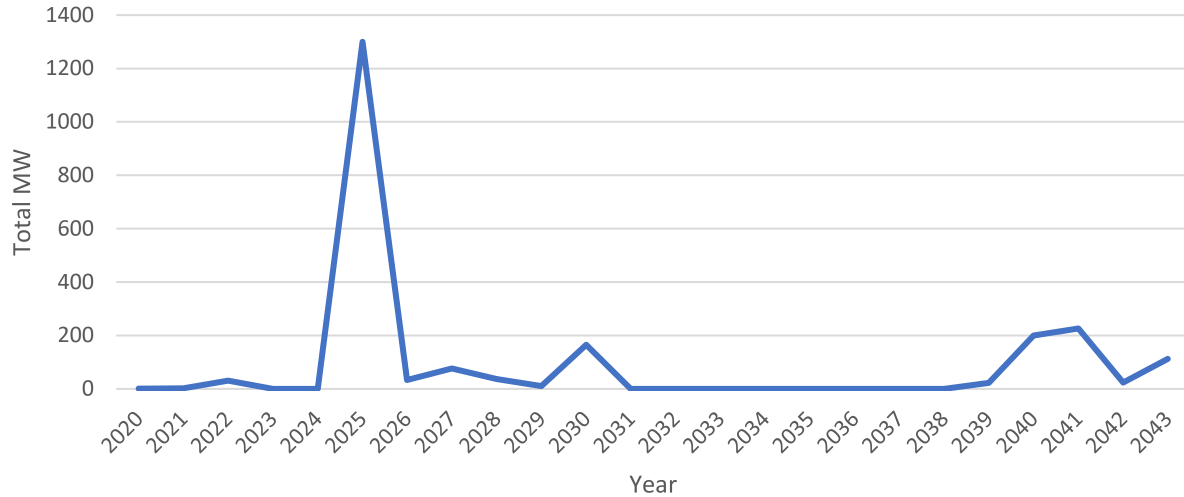


Source: MPSC QF Survey Data Provided by Utilities, February 2020

[11] CE chart does not include six PPAs on month-to-month contracts, two expired PPAs, one PPA with various contract terms, and one PPA with a year-to-year contract.
[12] DTE chart does not include six evergreen PPA contracts.

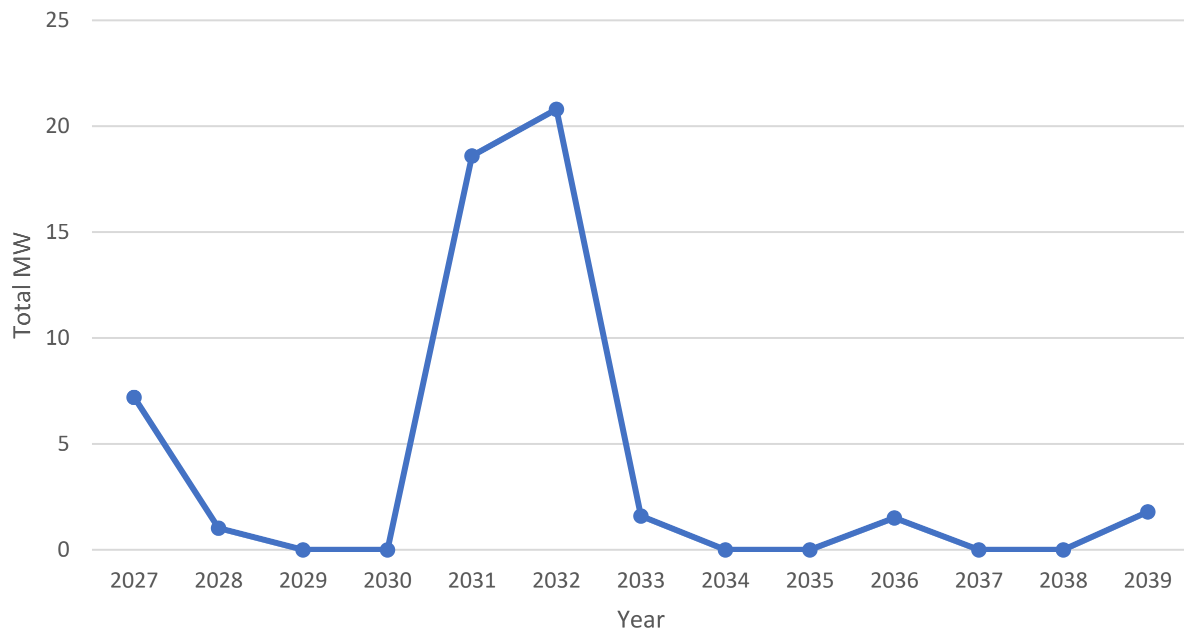
Figures 10 and 11, below, illustrate the generation capacity at risk each year as PPAs expire. Figure 10 includes projects in service and under development. Figure 11 includes projects in service because DTE does not have any new QFs with projects under development. Unless the contract with MCV is extended or modified, CE will experience a large decline in its PURPA capacity under contract (1,240 MW) in 2025. DTE's PURPA capacity has expiration dates spanning multiple years.

Figure 10: CE QF Contract Capacity Termination by Year



Source: MPSC QF Survey Data Provided by Utilities, February 2020

Figure 11: DTE QF Contract Capacity Termination by Year



Source: MPSC QF Survey Data Provided by Utilities, February 2020

Commission PURPA Activities

PURPA Technical Advisory Committee

The Commission issued an order on October 27, 2015 in Case No. U-17973 directing the Electric Reliability Division[13] to form a Technical Advisory Committee (TAC) to assess the continuing appropriateness of its current regulatory implementation regarding PURPA. The genesis for the order was potential new QFs inquiring about avoided cost rates and other factors as some existing PURPA contracts were expiring. The order directed the PURPA TAC to issue a report by April 8, 2016. On that date, the PURPA Technical Advisory Committee Report on the Continued Appropriateness of the Commission's Implementation of PURPA (PURPA TAC Report) was filed.

The PURPA TAC Report summarized the Staff's findings from the committee's five meetings. The report presented Staff's proposed administrative process for establishing a new avoided cost calculation methodology. Additionally, Staff proposed that investor-owned utilities were to update avoided cost calculations in contested cases biennially. For the avoided cost calculation, Staff recommended a hybrid proxy plant method where the avoided capacity cost would be based on the capital cost of a natural gas combustion turbine plant (NGCT). Avoided energy cost would be based on the forecasted cost of operating a natural gas combined cycle plant (NGCC), or actual or forecasted MISO locational marginal prices. Staff proposed that the QF can select the energy rate option that most effectively suits its needs. Staff also introduced a fixed investment cost attributable to energy (ICE) as a component of the avoided energy payment to QFs. The ICE component is added to account for the fixed-cost differences between a NGCT and a NGCC. Capacity needs would be forecasted for a 10-year planning horizon, as outlined in §292.302 (b)(2) of the PURPA regulations.

In the report, Staff recommended that the renewable energy credits (RECs) generated by the QF stay with the QF. Sale of RECs could be negotiated. Transmission costs and line loss mitigation with respect to the avoided cost calculation was recommended for case-by-case evaluation.

Staff also had recommendations for the Standard Offer tariff and rate. Staff supported a standard rate for existing QFs and QFs that are 5 MW and smaller. While past PURPA contracts had been long term, with some spanning over 30 years, Staff recommended a contract term that spans the shorter of either the QF financing period or 17.5 years for new QFs.

A draft version of the PURPA TAC report was circulated to the workgroup participants for comments. Staff reviewed the comments and incorporated them into the final version of the report where appropriate. All comments received were attached to the final report.

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[13] The Electric Reliability Division was reclassified as the Energy Resources Division effective April 8, 2018.

Commission PURPA Proceedings

After the PURPA TAC Report was issued, the Commission issued an Order on May 3, 2016, in Case Nos. U-18089 et al. directing investor-owned utilities to file their respective avoided cost information in their assigned dockets. The utilities were directed to calculate avoided cost using: 1) the hybrid proxy plant method proposed in the PURPA report; 2) the transfer price method developed under 2008 PA 295; 3) another method, if any, that the company wishes to propose; and 4) proposed standard rate tariffs, including applicable design capacity.[14] The status of these utility PURPA proceedings are discussed further below.

Avoided Cost and Standard Offer Tariff

PA 341 also directs the Commission to address avoided cost and a Standard Offer tariff. Section 6v(4) states that the Commission shall "[e]stablish a schedule of avoided cost prices updates for each electric utility."[15] There are several different methods for calculating avoided costs. The state commission (or, as applicable, the non-regulated utility) determines the method for calculating avoided costs. The chosen method must fit the definition of avoided cost and be non-discriminatory. The avoided cost methodology must also be consistent with FERC rules.[16]

PA 341 Section 6v(4) also states that the Commission shall "[r]equire electric utilities to publish on their websites template contracts for power purchase agreements for qualifying facilities of less than 3 megawatts that need not include terms for either price or duration of the contract. The terms of a template contract published under this subsection are not binding on either an electric utility or a qualifying facility and may be negotiated and altered upon agreement between an electric utility and a qualifying facility."[15] PURPA requires each utility to have standard rates for purchases from QFs with project design capacities of 100 kW or less. There may be standard rates for purchases from QFs with project design capacities greater than 100 kW. The Commission has addressed parameters of avoided cost, Standard Offer tariffs, and PPAs as part of the PURPA proceedings which are described later in this report.

Interconnection, Distributed Generation, and Legally Enforceable Obligation Standards

On November 8, 2018, the Commission issued an order opening Case No. U-20344 to initiate a stakeholder process to explore options for new interconnection, legally enforceable obligation, distributed generation, and legacy net metering rules and a formal rulemaking in accordance with the Administrative Procedures Act of 1969, MCL 24.201 *et seq*.

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[14] Order U-18089 et al. http://www.michigan.gov/documents/mpsc/u-18089etal_5_3_2016_565229_7.pdf
[15] MCL 460.6v(4)
[16]PURPA Title II Compliance Manual https://pubs.naruc.org/pub/B5B60741-CD40-7598-06EC-F63DF7BB12DC

The goal of this rulemaking effort is to clarify expectations for both utilities and independent generators, including QFs, seeking to interconnect to the utility's electric distribution system. The draft rules governing the three topics - interconnection, distributed generation program and legacy net metering, and PURPA legally enforceable obligation – are currently combined into a single ruleset. A stakeholder group was formed around each of the three topics; and each stakeholder group held several stakeholder meetings starting in December 2018 and continuing into 2020. Staff issued a first draft of the Interconnection, Distributed Generation, and Legally Enforceable Obligation Standards on August 28, 2019. After stakeholder meetings and a comment period, a second draft was issued on February 28, 2020.[17] A stakeholder meeting was held on March 24, 2020 and written comments are requested on May 1, 2020. Formal rulemaking is expected to commence later this year.

PURPA Proceedings

Alpena Power Company

Initial Filing

The Alpena Power Company (Alpena) filed an Application Providing Avoided Cost Methodology in Case No. U-18089 on June 17, 2016. Alpena is an investor-owned utility in Michigan with no company-owned generation facilities. Alpena purchases 100% of its power, with most of the purchased power supplied by CE under a contract that expires in 2024.[18]

After a prehearing conference and one round of testimony, Alpena filed a Settlement Agreement with the Commission on June 5, 2017 and an Amended Settlement Agreement on June 7, 2017. The amended settlement agreement stated that until January 1, 2025, Alpena's avoided cost is the cost that Alpena pays to CE for supplemental power under a 30-year contract ending December 31, 2024. On January 1, 2025, Alpena's avoided cost will be the rates for capacity and energy stated in the Standard Offer tariff.

The amended settlement agreement also stated that the Commission will review Alpena's avoided cost on a biennial basis. Alpena's Standard Offer tariff size cap will be 1 MW for the first two-year term prior to the first biennial review. Line loss savings will be evaluated on a case-by-case basis.

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[17] Both drafts of the Interconnection, Distributed Generation, and Legally Enforceable Obligation Standards can be found here: https://www.michigan.gov/mpsc/0,9535,7-395-93307_93312_93593_95590_95595_95689-508665--,00.html

[18] Under its CE contract, Alpena purchases two types of power, Firm and Supplemental. Alpena purchases 35 MW of firm power from CE on a continuous basis, measured and billed in kilowatt-hours. In addition to those purchases, Alpena also, on an as needed basis throughout each month, purchases Supplemental Power from CE to meet all energy demands above each month's purchase of its Firm Power purchase requirement.

All RECs will remain the property of the QF. The amended settlement agreement also included Alpena's proposed Standard Offer tariff sheets. The Commission approved the settlement agreement on December 6, 2018.

Biennial Review Filing

To comply with the settlement agreement, Alpena filed an Application for Review of Alpena Power Company's Avoided Cost Methodology on November 18, 2019 in Case No. U-18089. The Company's biennial review included an application, as well as updated tariff sheets. The application proposed that Alpena continue its current avoided cost methodology, as the Company still purchases the majority or its power from Consumers Energy Company. Alpena has proposed a change in the Standard Offer size cap – from 1 MW to 550 kW in order to be consistent with other Commission PURPA orders.

Alpena states in its application that when its contract with CE concludes on December 31, 2024, it will have secured a new all-requirements contract and the avoided cost methodology will be updated to reflect the new rates. Until a new contract is secured, Alpena has proposed that the Commission waive its biennial review in order to prevent unnecessary duplicate filings. Alpena will file a case to update avoided cost methodology within the statutory mandate of five years.

The Commission held a prehearing conference for Alpena's biennial review on January 9, 2020. Staff and intervenor testimonies were filed on February 18, 2020. This case is pending.

Consumers Energy Company

Consumers Energy Company (CE) filed an Application Providing Avoided Cost Methodology in Case No. U-18090 on June 17, 2016. On May 31, 2017, the Commission issued an order in this case approving Staff's hybrid-proxy plant method as the most appropriate method for calculating CE's avoided capacity and energy costs. A 10-year capacity planning horizon was also determined to be reasonable. The design capacity for the Standard Offer tariff was set at 2 MW, with term lengths to be set at five, 10, 15, or 20 years at the QF's option. This order also determined that any RECs generated would belong to the QF under the Standard Offer and PPAs. The Commission committed to reviewing PURPA rates every two years.

The May 2017 order remanded the case so that parties could file testimony addressing several inputs for calculating the avoided capacity cost using a natural gas combustion turbine unit (NGCT) and avoided energy cost using a natural gas combined cycle unit (NGCC) as proxy plants.

On July 31, 2017, a further order was issued in this case. This order provided guidance regarding inputs to the NGCT model, as well as an appropriate heat rate and assumed capacity factor for the NGCC proxy unit. However, the case was remanded a second time to allow parties to file testimony and exhibits supporting forecasted natural gas prices, including a levelized energy payment, a proposed energy payment schedule, and final Standard Offer tariff.

On November 21, 2017, the Commission issued a final order in this case. The order determined that the NGCT inputs from CE were appropriate and set the avoided capacity cost at

$140,505/ZRC-year. The order approved the use of regional Energy Information Administration (EIA) Forecasted Natural Gas Delivered Price. The order also determined that CE's inputs for NGCC fixed and variable cost should be included in calculations for fixed and variable operations and maintenance costs. The order also stated that because ICE is part of energy, the 2.37% line loss factor should be added to the sum of the avoided energy cost plus ICE. The Commission also found, in this order, that PURPA avoided costs should be integrated with capacity demonstration and integrated resource plan (IRP) proceedings.

After the final order was issued in this case, CE filed a Petition for Rehearing and Clarification on December 20, 2017. The Company also filed a Motion to Stay Capacity Purchase Obligation the same day. On December 20, 2017, CE also filed an Application to Reset Avoided Capacity Costs in Case No. U-18491. The Company submitted testimony that its capacity need had changed from what it filed in Case No. U-18090 and that it no longer had need for new capacity over the 10-year planning horizon. With no capacity need, CE stated that avoided capacity cost should be set at the MISO Planning Resource Auction (PRA) price for all new PURPA QF offers to sell capacity to the Company.

The same day, December 20, 2017, the Independent Power Producers Coalition of Michigan also filed a Petition for Rehearing in this case. The Commission also issued an order in this case on December 20, 2017. The order suspended implementation of avoided costs for capacity and energy until petitions for rehearing could be addressed. The order also suspended the Standard Offer tariff for CE.

After responses from the parties to this case, the Commission issued a subsequent order in this case on February 22, 2018. This order granted, in part, CE's Petition for Rehearing and reopened the U-18090 proceeding. CE was directed to file its final Standard Offer tariff and draft PPA by March 1, 2018. In the February 22 order, the Commission found that "…to allay any concerns that the company may find itself paying the full avoided capacity payment and becoming awash in unneeded QF capacity, the Commission finds it appropriate to limit payment of the full avoided capacity cost to the first 150 MWs in the queue." The order established a hearing date on March 13, 2018 and directed the Administrative Law Judge to complete a briefing by July 16, 2018 with an optional extension up to 30 days for good cause. Numerous parties participated in the reopening of this docket, which included petitions for rehearing from several parties.

While proceedings were continuing in U-18090, CE filed its IRP on June 15, 2018 in Case No. U-20165. CE proposed a competitive-bid process for procurement of capacity with resulting prices from the bidding determining PURPA avoided cost rates for the capacity portion when the utility has a capacity need. CE also proposed to compensate existing QFs at the full avoided cost most recently approved by the Commission. The IRP filing also included a request to reduce the Standard Offer cap from 2 MW to 150 kW and establish a three-year capacity outlook for PURPA purposes. CE proposed a financial compensation mechanism (FCM) incentive for all new PPAs that the Company enters into through the competitive bidding mechanism used to address future capacity needs.

An order issued by the Commission in Case No. U-18090 on October 5, 2018 denied the petitions for rehearing and lifted the suspension of implementation of the approved avoided costs in the December 20, 2017 order. The Standard Offer power purchase agreement for CE was approved, and the Company was instructed to revise its Standard Offer tariff sheets. This October 2018 order also directed CE to file an application for review of its avoided costs in Case No. U-20165, the docket opened for CE's IRP.

Geronimo Energy, a party to U-18090, filed a notice of appeal of the October 2018 order in the Michigan Court of Appeals on October 26, 2018. On February 4, 2019, CE filed a request to withdraw the Standard Offer tariff approved by the October 2018 order. Other parties filed petitions to intervene and in opposition of CE's application.

CE also filed an application on February 4, 2019 in Case No. U-20469 requesting an order to rescind the avoided cost rates established in Case No. U-18090. A June 7, 2019 order in Case No. U-18090 and U-20469 denied CE's requests to withdraw the Standard Offer tariff and to rescind the avoided cost rates established in U-18090.

The Administrative Law Judge issued a Proposal for Decision (PFD) in Case No. U-20165 on February 20, 2019. Thereafter, the majority of the parties reached a settlement agreement on March 23, 2019. An order issued on April 10, 2019 extended the statutory deadline of the IRP and set forth a filing schedule. On June 7, 2019, an order approved a contested settlement in the docket. The settlement agreement included provisions for CE's competitive solicitation, as well as FCM on new PPAs. It also established a five-year planning horizon for determining whether CE requires additional capacity. The Standard Offer power purchase agreement and tariff are applicable to QFs as large as 2 MW, however, there are separate avoided cost provisions for QFs at or below 150 kW and QFs between 150 kW and 2 MW.

On August 8, 2019, CE filed an application in Case No. U-20615 for Approval of a Settlement Agreement to Resolve Rights and Obligations Under the Public Utility Regulatory Policies Act of 1978. The application with an attached agreement was noticed to all QFs and other projects in CE's interconnection queue as of June 7, 2019. The agreement established a framework for allocating PURPA contracts to eligible QFs at the avoided cost rates set forth in Case No. U-18090. Under the framework, CE would enter into contracts with QFs for 170 MW of energy and capacity at the "full avoided cost" rates set forth in U-18090. Additionally, CE would enter into contracts with QFs for 414 MW of energy and capacity at the "energy only" avoided cost rates set forth in U-18090.[19] The settlement included a detailed description of how the projects would be awarded, based on cutoff dates within its interconnection queue. Uniform terms for the PPAs and parameters for interconnection were also included in the settlement agreement. The Commission

[19] Avoided capacity is paid at the applicable Midcontinent Independent System Operator Planning Reserve Auction rate.

issued an order in U-20615 on September 11, 2019 approving the settlement agreement and its terms.

To date, CE has filled the 170 MW of energy and capacity at the “full avoided cost” rates set forth in U-18090. On April 15, 2020, the Commission approved the Company’s applications to fill 394 MW of the 414 MW of energy and capacity at the “energy only” avoided cost rates set forth in U-18090. These PPAs can be accessed in the docket for Case No. U-20604.

DTE Electric

DTE Electric (DTE) filed an Application Providing Avoided Cost Methodology in Case No. U-18091 on June 17, 2016. The Commission issued an order on July 31, 2017. This order determined that the most appropriate method for calculating DTE’s avoided cost is Staff’s hybrid proxy plant method. The Commission also agreed with Staff’s (ICE) payment added to the energy cost to account for the difference between capital costs of a NGCT and a NGCC. A 10-year capacity planning horizon was found to be appropriate, as was a biennial PURPA review. The order also directed DTE to renew existing QF contracts at the full avoided cost rate.

The Commission order further addressed issues with the Standard Offer tariff. It determined that QFs should be able to choose five, 10, 15, or 20-year contract terms. The design capacity for the Standard Offer tariff was set at 2 MW for DTE. The Commission also determined that RECs generated by the QFs should remain assets of the QFs. This July 31, 2017 Order also remanded the case for further review. Parties were instructed to file proposed inputs to calculate avoided capacity cost based on a NGCT unit and avoided energy cost based on a NGCC unit and the ICE adder calculation by August 15, 2017. Parties were also instructed to file a proposed Standard Offer tariff with cost forecasts.

DTE filed a petition for rehearing in the case on August 30, 2017. The Company sited flawed methodology for calculating avoided cost rates, and questions about capacity need among its reasons for a rehearing. The Commission issued an order on December 20, 2018 granting rehearing. The case was remanded for the purpose of addressing inputs to be used for avoided costs based on the NGCC plant approved in Case No. U-18419, DTE’s capacity needs, and the Standard Offer tariff consistent with an avoided cost methodology based on the gas plant approved in U-18419. The Commission granted three companies intervention in the remand in a February 21, 2019 order.

On March 29, 2019, DTE filed its IRP in Case No. U-20471. DTE reiterated its plans to renew all existing PURPA contracts and pointed to the pending case in U-18091 for PURPA related issues.

In the order issued on September 26, 2019 in Case No. U-18091, the Commission (1) denied petitions for rehearing and affirmed its decision to set the Standard Offer cap at 550 kW to be reviewed in the Company’s IRP and next biennial review of the company’s avoided cost; (2) adopted the avoided costs proposed by DTE in a scenario where the company requires capacity; (3) approved the use of MISO PRA for an avoided capacity rate and MISO Locational Marginal

Pricing (LMP) for an avoided energy rate when the company does not have a capacity need in the manner described above; (4) adopted the energy forecast and inputs proposed by DTE for use in determining avoided costs; (5) found the company did not have a capacity need, (6) approved a Standard Offer tariff and Standard Offer PPA; and (7) adopted a five-year planning horizon.

On February 20, 2020, The Commission issued an order in both U-18091 and U-20471, as well as DTE's Renewable Energy Plan Case No. U-18232. Among other issues, the Commission ordered DTE to file an application for review of its compliance with PURPA no later than November 13, 2020.

Indiana Michigan Power Company

Indiana Michigan Power Company (I&M) filed an Application Providing Avoided Cost Methodology in Case No. U-18092 on June 30, 2016. I&M is a utility organized and existing in Indiana and authorized to do business in Michigan. I&M's application stated that it currently uses avoided cost data based on estimates of the fixed costs of a combustion turbine and I&M's avoided cost of energy. These three-year average avoided cost calculations support current Standard Offer rates in I&M's cogeneration tariff. The current methodology is approved by the Indiana Utility Regulatory Commission. An order was issued on December 20, 2018 remanding the proceeding for the limited purposes of updating I&M's energy price forecasts that properly reflect the PJM market construct and receiving into evidence information on effective load carrying capability, the Company's capacity need, and options for a planning horizon.

After testimony from I&M and the Commission Staff was filed, a settlement agreement was filed on February 25, 2019. This settlement agreement was approved in an order issued on March 21, 2019. The order approved I&M's Standard Offer tariff and updates to the energy price forecasts, based on the PJM market construct. The order found that because I&M currently does not have a capacity need, the Company's capacity payment is set at zero and need not be included in the Standard Offer at this time.

I&M filed its IRP in Case No. U-20591 on August 14, 2019. Staff has recommended that I&M utilize a 5-year planning horizon to evaluate capacity need for PURPA. The IRP case schedule was suspended on February 28, 2020 to facilitate settlement discussions.

Northern States Power Company-Wisconsin

Northern States Power Company-Wisconsin (NSP-W) filed an Application Providing Avoided Cost Methodology in Case No. U-18093 on June 30, 2016. NSP-W is an investor-owned utility that generates, transmits, distributes, and sells electric energy. NSP-W utilizes a planning mechanism called Upper Midwest Resource Plan. This plan is filed with the Minnesota Public Utilities Commission and is updated every two years. The plan includes a five-year action plan and a 15-year planning period. NSP-W currently has no QFs in its Michigan service territory.

The Commission issued an order in this case on December 20, 2018. The Commission found that avoided costs for capacity should be based on the Staff's proxy CT methodology when the

Company has a capacity need within the planning horizon. When there is no capacity need within the planning horizon, the avoided capacity price shall be zero. NSP-W was instructed to address its capacity need as it pertains to PURPA in its IRP application. The Commission also ordered NSP-W to file a biennial review of its avoided costs on December 21, 2020.

NSP-W filed its IRP in Case No. U-20599 on July 31, 2019. The Company addressed its capacity need as it pertains to PURPA, as directed by the December 2018 order in U-18093. NSP-W continues to forecast no capacity need for the first five years of its 10-year planning horizon, therefore its avoided capacity cost should remain at zero. A February 6, 2020 order in the IRP docket approved a settlement agreement for this case.

Upper Peninsula Power Company

Upper Peninsula Power Company (UPPCO) filed an Application Providing Avoided Cost Methodology in Case No. U-18094 on June 17, 2016. UPPCO is a small utility located in Michigan's Upper Peninsula, and as such, constructing generation assets would likely not be the most effective way to fulfill the capacity and energy needs of its customers. The company has a contract for capacity through May 31, 2020. The Commission issued an order in this case on September 28, 2017 finding that until May 31, 2020, UPPCO's avoided capacity cost should be set at its capacity contract price at the time that the PURPA contract is entered into, with an adjustment for effective load carrying capability (ELCC)[20] applied. After May 2020, the appropriate method for calculating avoided capacity cost will be addressed at UPPCO's next PURPA review. The Commission directed UPPCO to file its PURPA review application by February 1, 2019. A 10-year planning horizon for capacity requirements was found to be appropriate for UPPCO.

The order also states that a QF may opt for an avoided energy cost based either on LMP at the time the energy is delivered or on UPPCO's forecasted LMP. For LMP to have forecasts for 20 years in the record, the case was remanded, and the parties were directed to file LMP forecasts by October 16, 2017.

The Standard Offer tariff, as addressed in the order, shall be available for a term of five, 10, 15, or 20 years at the QF's discretion. A 1 MW cap was found to be reasonable given the size and limited capacity needs of UPPCO. As part of the remand to reopen these proceedings, parties were directed to file updated Standard Offer tariffs including LMP energy rates for five, 10, 15, and 20 years and line losses by voltage level.

After testimony was filed in response to the September 2017 remand order, a Settlement Agreement was filed on December 15, 2017. The Settlement Agreement included an LMP forecast

[20] ELCC is the amount of incremental load a resource, such as wind, can dependably and reliably serve, while considering the probabilistic nature of generation shortfalls and random forced outages as driving factors for load not being served.

for five, 10, 15, and 20 years, as well as a Standard Offer tariff from UPPCO. The Commission issued an order on January 23, 2018 approving the Settlement Agreement.

UPPCO filed a motion on January 29, 2019 to extend the February 1, 2019 deadline for its PURPA review. The Company proposed integrating the PURPA review into its IRP filing on February 12, 2019. The Commission approved this motion in an order issued on February 7, 2019.

UPPCO's IRP was filed on February 12, 2018 in Case No. U-20350. The Company included its PURPA review in this filing. The Commission issued an interim order in this case on December 6, 2019 recommending changes to UPPCO's IRP application. UPPCO responded with an amended IRP application that was filed on January 7, 2020. A settlement agreement was negotiated and filed on January 21, 2020. The settlement agreement included a five-year planning horizon for PURPA capacity and lowering UPPCO's Standard Offer tariff cap to 550 kW. Avoided cost energy payments will be determined based upon a five-year fixed schedule on peak and off peak LMP rate. This will be followed by a five-year variable rate of actual MISO LMP at UPPCO's pricing node. Avoided capacity cost is set at the MISO PRA price. The Commission approved this settlement agreement in an order dated February 6, 2020.

Upper Michigan Energy Resources Corporation

Wisconsin Electric Power Company (WEPCo) and Wisconsin Public Service Corporation (WPS) issued Applications Providing Avoided Cost Methodology in Case Nos. U-18096 and U-18095 on June 30, 2016. The two cases were consolidated on December 7, 2016. WEPCo filed two proposed customer generation tariffs in its Application to reflect standard rates for purchasing from QFs. WPS filed its standard rates for purchasing from QFs within its three parallel generation tariffs. The WPS Application also referenced the formation of a new utility, Upper Michigan Energy Resources Corporation (UMERC) pending in Case No. U-18061.

The application explained that after the formation of UMERC in January 2017, all the Michigan customers from WEPCo and WPS would be transferred to UMERC, with the exception of the Tilden Mining Company L.C. (Tilden). Tilden would remain a customer of WEPCo under a special contract approved by the Commission, in Case No. U-17862 on April 23, 2015, until UMERC places new generation in service. UMERC will be a small utility and will contract power from WEPCo and WPS under full requirements PPAs. As described in Case No. U-18224, a Certificate of Necessity (CON) was filed for UMERC to construct two reciprocating internal combustion engine (RICE) electric generation facilities in Michigan's Upper Peninsula (UP). The PPAs between UMERC and WEPCo and WPS would remain in effect until the RICE units become operational. With these RICE units in operation, UMERC would have excess generation. Because it would only serve a single customer (Tilden) until 2019, WEPCo submitted testimony that it is unnecessary to establish an avoided cost.

The Commission issued an order on December 20, 2018. The order agreed that PURPA did not apply to WEPCo in Michigan. For UMERC, the order directed the Company to adopt an avoided capacity cost based on MISO capacity market values. The order also stated that UMERC shall adopt avoided energy costs that reflect the forecasted market values for energy used in the CON proceeding. These fixed forecasted values shall be used for the first five years of the Standard Offer contract term beginning in 2019. After the first five years, the avoided costs shall shift from a fixed forecasted rate to a variable rate. The order also established the option for a QF to select a five-, 10-, 15-, or 20-year contract for the Standard Offer tariff. UMERC was ordered to file updates to its Standard Offer tariff in this docket, and file for a biennial review of its avoided costs on December 21, 2020.

An avoided cost fact sheet summarizing current avoided cost information for each investor-owned utility is provided in **Appendix B**.[21]

Supplemental, Backup, Maintenance, and Interruptible Power (Standby Service)

There has been increasing interest in rates for utility standby service. Standby service is a benefit provided by the utility that makes energy and capacity available to the customer in the event that a customer's generator is unable to operate. Standby rates are paid by retail customers who have on-site electric generating facilities and use the utility for back-up service. PURPA requires utilities to provide standby service to QFs on a non-discriminatory basis. In an order issued on November 2015, the Commission directed Staff to establish the Standby Rate Working Group (SRWG) to review current standby tariffs and develop recommendations for improvements to these tariffs. The SRWG met six times in 2016 with participation from utilities, current and future standby customers, and Commission Staff. The meetings included presentations and discussions. Comments were also accepted on drafts of each report before being issued by the SRWG.

The first report was issued on August 19, 2016. The primary focus of that report was solar generation. The report outlined the main rate components of standby tariffs and summarized the tariffs used by CE and DTE. "The preliminary analysis completed by Staff as part of the SRWG activities indicates that it is not necessary for non-residential, self-generation solar projects to take service under a standby service tariff provided the normal service tariff incorporates a delivery demand charge and either a power supply demand charge or accurate time of use rates."[22] Staff indicated that a supplemental report was needed to address non-intermittent standby service tariff design and to update its solar standby recommendations if needed.

The second report from the SRWG was issued in June of 2017. The supplemental report focused on non-intermittent standby service tariff design. The report also presented Staff's recommendations on standby service tariffs for both combined heat and power (CHP) and solar self-generation. The SRWG issued a list of seven recommendations for standby service tariffs.

[21] A copy of the Avoided Cost Fact Sheet is updated by the MPSC here: https://www.michigan.gov/documents/mpsc/Avoided_Cost_Fact_Sheet_092619_666644_7.pdf

[22] Standby Rate Working Group (SRWG) Report https://mi-psc.force.com/s/filing/a00t0000005pVNCAA2/u177350392

These recommendations can be found in the Standby Rate Working Group Supplemental Report.[23]

Standby rates have been traditionally reviewed in rate cases. In the most recent rate cases of CE and DTE, standby rates have been included as a rate case issue.[24] PURPA includes a provision requiring utilities to provide standby service as follows:

> (c) Rates for sales of back-up and maintenance power. The rate for sales of back-up power or maintenance power
>
> > (1) Shall not be based upon an assumption (Unless supported by factual data) that forced outages or other reductions in the electric output by all qualifying facilities on an electric utility's system will occur simultaneously, or during the system peak, or both: and
> >
> > (2) Shall take into account the extent to which scheduled outages of the qualifying facilities can be usefully coordinated with scheduled outages of the utility's facilities.[25]

Section 6v of PA 341 also directs the Commission to "[r]equire that any prices charged by an electric utility for maintenance power, backup power, interruptible power, and supplementary power and all other such services are cost-based and just and reasonable."[26] The Commission has determined the appropriate forum for addressing this issue from a procedural standpoint in Case No. U-18090 in its May 31, 2017 order. The Commission found that the "other rate elements of PURPA, namely, maintenance, backup, interruptible, and supplementary power, and other services, are being addressed in other proceedings and need not be addressed here."[27]

PURPA Notice of Proposed Rulemaking

On September 19, 2019, FERC issued a Notice of Proposed Rulemaking (NOPR) establishing FERC's comprehensive review of its PURPA regulations. FERC proposes to "to grant state

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[23] https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t0000001UMMSAA4

[24] CE's Rate Case No. U-20697 https://mi-psc.force.com/s/case/500t000000PnlcRAAR/in-the-matter-of-the-application-of-consumers-energy-company-for-authority-to-increase-its-rates-for-the-generation-and-distribution-of-electricity-and-for-other-relief was filed on February 27, 2020. DTE's Rate Case No. U-20561 https://mi-psc.force.com/s/case/500t000000IpcKBAAZ/in-the-matter-of-the-application-of-dte-electric-company-for-authority-to-increase-its-rates-amend-its-rate-schedules-and-rules-governing-the-distribution-and-supply-of-electric-energy-and-for-miscellaneous-accounting-authority was filed on July, 3, 2019 and is awaiting an order.

[25] 18 CFR 292.305

[26] MCL 460.6v(4)

[27] May 31, 2017 order in Case No. U-18090 https://mi-psc.force.com/s/filing/a00t0000005ppT3AAI/u180900162

regulatory authorities that oversee regulated electric utilities and nonregulated electric utilities (collectively, for ease of reference, referred to as states) the flexibility in key respects to incorporate competitive market pricing in the rates paid by electric utilities to qualifying small power production facilities and qualifying cogeneration facilities under PURPA (collectively, QFs)."[28] The NOPR is summarized into eight main sections of proposals, described below.

First, FERC proposes to grant states the flexibility to establish variable energy rates in QF power sales contracts and other legally enforceable obligations. The variance would be in accordance with changes in the purchasing utility's as-available avoided costs at the time the energy is delivered. Second, FERC proposes to grant states additional flexibility to allow QFs to have a fixed energy rate that is based on projected energy prices during the term of a QFs contract.

The third FERC proposal is to grant states the flexibility to set "as-available" QF energy rates at competitive prices from liquid market hubs or calculated from a formula based on natural gas price indices and specified heat rates. States would also have the flexibility to set energy and capacity rates pursuant to a competitive solicitation process conducted using transparent and non-discriminatory procedures.

A fourth proposal is a reduction in an electric utility's obligation to purchase from QFs based on the extent to which the purchasing utility's supply obligation has been reduced by a state retail choice program.

The fifth proposal from the NOPR is a modification of the current "one-mile rule" for determining whether generation facilities should be considered part of a single facility for purposes of determining qualification as a small power production facility. FERC proposes that facilities between one and ten miles apart are actually a single facility. FERC also proposes the addition of a definition of the term "electrical generating equipment" to clarify how the distance between facilities would be calculated.

Current PURPA regulations provide for the termination of an electric utility's obligation to purchase from a QF with nondiscriminatory access to certain markets. The current rebuttable assumption is that a QF with a net capacity at or below 20 MW does not have nondiscriminatory access to certain markets. In the sixth proposal, FERC proposes to reduce the rebuttable assumption for small power production facilities (but not cogeneration facilities) from 20 MW to 1 MW.

The seventh FERC proposal pertains to legally enforceable obligation (LEO). FERC proposes to clarify that a QF must demonstrate commercial viability and financial commitment to construct its facility, based on state-determined criteria, before the QF is entitled to a contract or LEO.

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[28] https://www.ferc.gov/whats-new/comm-meet/2019/091919/E-1.pdf

The final proposal from the NOPR would allow a party to protest self-certification or self-recertification of a facility without the filing of a separate petition for declaratory order and without the associated filing fees.

The Commission filed timely NOPR comments on December 3, 2019, making observations about Michigan's implementation of PURPA and identifying areas that may warrant clarification.[29] Staff will continue to monitor the NOPR, as well as any FERC decisions, for further PURPA reform.

Conclusion

The Commission appreciates the electric utilities providing the QF data needed to prepare this second report issued pursuant to Act 341, Section 6v. PURPA-related activities are in progress at the Commission related to QF interconnection with the utility, establishing updated avoided costs and Standard Offer tariff parameters, and reviewing standby service rates. A process to update the Commission's rules governing electric utility interconnection, distributed generation, and legally enforceable obligation is in progress. The proposed PURPA updates in the FERC NOPR are being closely monitored. The Commission looks forward to continuing its efforts related to PURPA implementation and providing its next report by April 20, 2022.

[29] https://elibrary.ferc.gov/IDMWS/file_list.asp

Appendices

Consumers Energy: Contracts					
Developer Name	**Company**	**Quantity**	**Renewable Energy Type**	**Commission Approval**	**Term Ending**
STS Hydropower, Ltd.	Ada Hydroplant	1.4 MW	Hydroelectric	7/31/2017	5/31/2022
Viking Energy Corporation	Lincoln Plant	18 MW	Biomass	4/18/2019	5/31/2027
Viking Energy Corporation	McBain Plant	18 MW	Biomass	4/18/2019	5/31/2027
Hillman Power Company	Hillman	16.3 MW	Biomass	7/2/2019	12/31/2022
NANR	Rathbun Plant	1.6 MW	Landfill Gas	9/26/2019	5/31/2039
Commonwealth Power Company	LaBarge Hydro Plant	0.80 MW	Hydroelectric	9/26/2019	5/31/2039
Crystal Flash Renewable Energy,	Mackinaw City Plant	1.8 MW	Wind	11/14/2019	5/31/2021
Grenfell, Inc.	Belding Plant	0.3 MW	Run-of-River Hydroelectric	11/14/2019	5/31/2039
Good Fruit Storage, LLC	Good Fruit Storage, LLC	0.179 MW	Solar	12/6/2019	5/31/2040
NextSun Energy, LLC	Workman Road Solar	2 MW	Solar	12/6/2019	9/29/2040
	Surrey Road Solar	2 MW	Solar	12/6/2019	9/29/2040
	Morey Road Solar	2 MW	Solar	12/6/2019	9/29/2040
	Lake City Solar	2 MW	Solar	12/6/2019	9/29/2040
Cypress Creek Renewables	Hazel Solar, LLC	2 MW	Solar	12/6/2019	8/18/2040
	Hendershot Solar, LLC	2 MW	Solar	12/6/2019	8/18/2040
	Jack Francis Solar, LLC	2 MW	Solar	12/6/2019	8/3/2040
	May Shannon Solar, LLC	2 MW	Solar	12/6/2019	8/3/2040
	13 Mile Solar, LLC	2 MW	Solar	12/6/2019	8/18/2040
	Angola Solar, LLC	2 MW	Solar	12/6/2019	8/18/2040
	Captain Solar, LLC	2 MW	Solar	12/6/2019	8/3/2040
	Coldwater Solar, LLC	2 MW	Solar	12/6/2019	8/3/2040
	Geddes 2 Solar, LLC	2 MW	Solar	12/6/2019	9/14/2041

Appendix A

Consumers Energy: Contracts					
Developer Name	**Company**	**Quantity**	**Renewable Energy Type**	**Commission Approval**	**Term Ending**
Cypress Creek Renewables	Interchange Solar, LLC	2 MW	Solar	12/6/2019	8/18/2040
	Bullhead Solar, LLC	2 MW	Solar	12/6/2019	9/14/2041
	Geddes 1 Solar, LLC	2 MW	Solar	12/6/2019	9/14/2041
	Stoneheart Solar, LLC	2 MW	Solar	12/6/2019	12/8/2040
	Woodley Solar, LLC	0.821 MW	Solar	12/6/2019	12/8/2040
	Macbeth Solar, LLC	20 MW	Solar	12/6/2019	12/24/2041
Geronimo Energy	Bingham Solar, LLC	20 MW	Solar	12/6/2019	11/30/2040
	Temperance Solar, LLC	20 MW	Solar	12/6/2019	11/30/2040
sPower Development Company, LLC	Cement City Solar, LLC	20 MWac	Solar	12/19/2019	12/31/2041
	Letts Creek Solar, LLC	15 MWac	Solar	12/19/2019	12/31/2041
	Pullman Solar, LLC	20 MWac	Solar	12/19/2019	12/31/2041
	Thorn Lake Solar, LLC	20 MWac	Solar	12/19/2019	12/31/2041
Inman Solar Incorporated	Arthur Solar Farm, LLC Plant	1.827 MWac	Solar	4/15/2020	12/31/2040
	Golden Solar Farm, LLC Plant	1.828 MWac	Solar	4/15/2020	12/31/2040
	Robert Swift Solar Farm, LLC Plant	1.828 MWac	Solar	4/15/2020	12/31/2040
Various Developers	Byrne Solar, LLC	5 MWac	Solar	4/15/2020	7/15/2041
	Aluminum Solar, LLC	8 MWac	Solar	4/15/2020	9/1/2041
	TART Solar, LLC	8.49 MWac	Solar	4/15/2020	6/30/2041
	Albion Solar, LLC	10 MWac	Solar	4/15/2020	9/15/2040
	Bamboo Solar, LLC	10 MWac	Solar	4/15/2020	10/15/2040
	Burns Park Solar, LLC	10 MWac	Solar	4/15/2020	10/15/2040
	Congo Solar, LLC	10 MWac	Solar	4/15/2020	10/15/2040

Appendix A

Consumers Energy: Contracts					
Developer Name	**Company**	**Quantity**	**Renewable Energy Type**	**Commission Approval**	**Term Ending**
Various Developers	Johnsfield Solar, LLC	10 MWac	Solar	4/15/2020	8/15/2040
	Lightfoot Solar, LLC	10 MWac	Solar	4/15/2020	10/15/2040
	Rosco Solar, LLC	10 MWac	Solar	4/15/2020	9/1/2040
	Stockholm Solar, LLC	10 MWac	Solar	4/15/2020	10/20/2040
	Surbrook Solar, LLC	10 MWac	Solar	4/15/2020	10/15/2040
	Ulysses Solar, LLC	10 MWac	Solar	4/15/2020	9/1/2041
	Allegheny, LLC	10.699 MWac	Solar	4/15/2020	10/1/2041
	Hogan Solar, LLC	12 MWac	Solar	4/15/2020	8/15/2040
	Swede Solar, LLC	12 MWac	Solar	4/15/2020	10/15/2040
	Blue Elk Solar VII, LLC	12.331 MWac	Solar	4/15/2020	5/5/2043
	Blue Elk Solar I, LLC	20 MWac	Solar	4/15/2020	5/5/2043
	Blue Elk Solar III, LLC	20 MWac	Solar	4/15/2020	5/5/2043
	Blue Elk Solar IV, LLC	20 MWac	Solar	4/15/2020	5/5/2043
	Beaverton Solar, LLC	20 MWac	Solar	4/15/2020	8/1/2041
	Cloudbreak Solar, LLC	20 MWac	Solar	4/15/2020	9/15/2040
	Lyons Road Solar Farm, LLC	20 MWac	Solar	4/15/2020	9/1/2040
	Shipsterns Solar, LLC	20 MWac	Solar	4/15/2020	5/15/2041
	Topanga Solar, LLC	20 MWac	Solar	4/15/2020	10/1/2040
	Willford Solar, LLC	20 MWac	Solar	4/15/2020	9/1/2040
	Greenstone Solar, LLC	20 MWac	Solar	4/15/2020	5/5/2043
	Midcontinent Solar, LLC	20 MWac	Solar	4/15/2020	5/5/2043

Appendix B

Michigan Public Service Commission

Avoided Cost Fact Sheet

MPSC

2/6/2020

The Public Utility Regulatory Policies Act (PURPA) encourages competition, conservation, reliability, and efficiency in generating and delivering electricity. PURPA established a class of generating facilities known as qualifying facilities (QFs). Michigan utilities are required to buy power generated by a QF smaller than 20 MW and are bound to compensate QFs based on the host utility's avoided cost. An electric utility's avoided cost is the amount the utility would pay to a QF in the utility's service area that is equal to the amount the utility would have to pay to generate the power itself or purchase from another source. This gives the QF an opportunity to produce power and be compensated at the appropriate avoided cost rate.

Company	Case No.	Status	Avoided Energy (per kWh)	Avoided Capacity (per kWh)	Standard Offer Tariff	Max Capacity Standard Offer
Consumers Energy	U-18090	6/7/2019 Order in U-20165	***QFs at or below 150 kW***		Standard Offer Rate Schedules	2 MW
			Avoided cost based on competitive bid results regardless of capacity need			
			QFs over 150 kW			
			With Capacity Need: avoided cost based on competitive bid results	With Capacity Need: avoided cost based on competitive bid results		
			Without Capacity Need: contract rates option of i) 15-year contract based on actual LMP, or ii) 10-year contract with years 1-5 based on scheduled energy rates 2.67¢-3.97¢ & years 6-10 equal to the year 5 forecasted rate	Without Capacity Need: MISO PRA		
DTE	U-18091	9/26/2019 Order	With Capacity Need: Years 1-5 based on forecasted energy rates 2.52¢-3.41¢, then variable rate based on actual energy cost of Bluewater Energy Center	With Capacity Need: 1.4¢	Pending	550 kW
			Without Capacity Need: contract rates option of i) Years 1-5 based on forecasted LMP energy rates 2.39¢-3.56¢, then variable rate based on actual LMP ii) Actual LMP	Without Capacity Need: MISO PRA		
Alpena Power Company	U-18089	12/6/2018 Order	Historically 3.928¢-4.425¢ (rolling average based on contract with Consumers Energy)	1.74¢-1.87¢	Standard Offer Rate Schedules (D35-41)	1 MW
Indiana Michigan Power Company	U-18092	3/21/2019 Order	Years 1-5 based on forecasted LMP energy rates 2.42¢-4.41¢, then variable rate based on actual LMP	$0	Standard Offer Rate Schedules (D62-68)	550 kW
Northern States Power Company	U-18093	12/20/2018 Order	Years 1-5 based on forecasted LMP energy rates 2.92¢-4.05¢, then variable rate based on actual LMP	$0	Standard Offer Rate Schedules	550 kW
Upper Peninsula Power Company	U-18094	2/6/2020 Order in U-20350	Years 1-5 based on forecasted LMP energy rates 2.78¢-4.32¢, then variable rate based on actual LMP	MISO PRA	Pending	550 kW
Upper Michigan Energy Resources Corporation	U-18095	12/20/2018 Order	Years 1-5 based on forecasted LMP energy rates 2.61¢-3¢, then variable rate based on previous year LMP	0.01¢-0.03¢	Standard Offer Rate Schedules (D58-60.08 & 143-150)	550 kW

Questions about the information in this fact sheet can be sent to Merideth Hadala: HadalaM@michigan.gov

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