STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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In the matter, on the Commission's own motion, to initiate an inquiry into the methods and approaches for determining utility capacity needs over a 10-year planning horizon to establish or update avoided capacity costs.	)	Case No. U-20095

I. INTRODUCTION

Ranger Power LLC ("Ranger") appreciates the opportunity to submit these comments to the Michigan Public Service Commission ("MPSC"). Ranger is a utility-scale solar development company that is focused on bringing cost-effective clean energy to Michigan and other Midwestern states. Ranger is developing several projects across the state, including several which are Qualifying Facilities under the Public Utility Regulatory Policies Act of 1978 ("PURPA"). Ranger is committed to working closely with landowners, communities, and regulators to bring new investment, jobs, and clean energy to Michigan. Ranger is led by an experienced team of developers and renewable energy specialists and has successfully developed early-, mid-, and late-stage solar projects across the country.

The following comments are broken down into the broad issue categories we perceive in the Commission's list of issues for comment in the February 22, 2018 Order in U-20095.

II. ON THE IMPLEMENTATION OF A 10-YEAR PLANNING HORIZON

A. Should capacity need be determined in an IRP?

We believe that an IRP is a reasonable process through which to establish capacity need, so long as the process requires a long-term forecast of utility capacity needs and provides transparency into utility needs on a going-forward basis. Such transparency and stability are

essential so that QFs will know whether a utility has capacity needs at the time of submittal of an interconnection request and establishment of a legally enforceable obligation ("LEO").

In order to determine a utility's capacity need, a long-term view must be taken in order to ensure stability for QF planning, as well as utility planning. The utility's own planning horizons are decades out, and new utility generating resources are expected to serve the utility for decades, so capacity need should be evaluated over the utility's planning horizon (no less than 10 years), and not based solely on immediate need. For purposes of PURPA, where QF resources are required to be treated in a manner that is non-discriminatory with respect to the utility's own resources, the evaluation of need should be based on potential for replacing some or all of the utility's own next-build generation. It is worth keeping in mind the FERC's remarks in the order implementing their PURPA regulations, "[w]ith regard to capacity, if a purchase from a qualifying facility permits the utility to avoid the addition of new capacity, then the avoided cost of the new capacity and not the average embedded system cost of capacity should be used." Order 69, 45 FR 12216.[1] In order to know what new capacity a utility would be avoiding building by purchasing capacity from a PURPA facility, there must be a long-term review of utility capacity planning and need. An IRP is an appropriate place for that process.

B. If a utility claims a change in capacity need, when should the PSC reset the capacity price?

In resetting capacity prices, the Commission must be cognizant of the fact that QFs have an option to elect time-of-obligation pricing, which would set a stable capacity price based on a forecast. For QFs with such contracts, changes in capacity pricing made during the contract period

[1] *Final Rule Regarding the Implementation of Section 210 of the Public Utility Regulatory Policies Act of 1978*, Order No. 69, FERC Stats. & Regs. ¶ 30,128 at 22216 order on reh'g, Order No. 69-A, FERC Stats. & Regs. ¶ 30,160 (1980), *aff'd in part & vacated in part sub nom. Am. Elec. Power Serv. Corp.* v. *FERC*, 675 F.2d 1226 (D.C. Cir. 1982), *rev'd in part sub nom. Am. Paper Inst*. v. *Am. Elec. Power Serv. Corp.*, 461 U.S. 402 (1983) ("Order 69.")

should not affect contract prices unless the contract specifically allows for such. In addition, capacity prices should not be able to be altered, suspended, or otherwise adjusted by the unilateral action of the utility but must be done through a Commission proceeding. Before a utility should be allowed to invoke a lack of capacity need to avoid paying its full avoided capacity costs, it must be required to first seek a review from the Commission and other interested parties of the bases for that claim.

C. When a utility claims a change in need for capacity, how should QFs in the queue be treated?

Transparency is the key requirement that QFs need for purposes of project planning and financing. To that end, a unilateral "claim" by the utility should not be sufficient to change the rights of QFs. Requiring a Commission process to review and approve and proposed change enables QFs in the queue and otherwise notice of likely change in capacity need and the opportunity to adjust project planning accordingly. Clear rules and a transparent process help to ensure that neither utilities nor QFs are harmed financially by sudden changes in the regulatory landscape.

III. HOW AND WHEN A LEGALLY ENFORCEABLE OBLIGATION ("LEO") IS FORMED

A. What criteria should Commission use in determining when a LEO has been created?

Again, the principles of transparency and regulatory clarity are of paramount importance in Ranger's experience. These principles also are consistent with the reason why the requirement for a "legally enforceable obligation" was created by the FERC in the first place. When the FERC implemented its PURPA regulations in 1980, it was concerned that if they used the term "contract," this would essentially put the utilities in control, for if the utilities were to refuse to enter into a contract, they would be able to prevent long-term purchase obligations. Thus, in Order 69, the

FERC stated, "[u]se of the term 'legally enforceable obligation' is intended to prevent a utility from circumventing the requirement that provides capacity credit for an eligible qualifying facility merely by refusing to enter into a contract with the qualifying facility." FERC Order 69, 45 FR at 12224. This principle is therefore reflected in the requirements in 18 CFR § 292.304(d) and the requirement that a QF can sell and a utility must purchase pursuant to a legally enforceable obligation. See *Va. Elec. and Power Co.*, 151 FERC ¶ 61,006, at pp. 23-24, and *Cedar Creek Wind, LLC*, 137 FERC ¶ 61,006, at p. 36 (finding that a state requirement that a legally enforceable obligation can result only from a fully executed contract is inconsistent with PURPA and FERC's regulations).

The foundational principle is that by committing itself to sell, a QF commits the utility to purchase, pursuant either to a contract or to a LEO. See *JD Wind 1, LLC*, 130 FERC ¶ 61,127 (2010) at ¶ 7 ("a QF, by committing itself to sell to an electric utility, also commits the electric utility to buy from the QF "), *Cedar Creek Wind*, 137 FERC ¶ 61006 (2011) at ¶ 32, and *FLS Energy* 157 FERC ¶ 61211 (2016), ¶ 24 *(*"The establishment of a legally enforceable obligation turns on the QF's commitment, and not the utility's actions.").

IV. SHOULD A COMPETITIVE PROCESS BE USED FOR THE PROCUREMENT OF QF CAPACITY?

While a competitive process represents good utility practice for containing costs, the process does not fit well within the requirements of PURPA. PURPA is not designed to promote the lowest cost option, but rather to encourage QF development. Therefore, under the statute and the FERC's rules, the price paid to QFs is supposed to be the same as the cost the utility would incur for its own generation. Where utilities are not required to obtain all their new capacity through a competitive process, putting such a requirement in place for PURPA capacity would be

discriminatory. FERC has thus opposed the use of competitive solicitations in order to obtain PURPA contracts:

> we find that requiring a QF to win a competitive solicitation as a condition to obtaining a long-term contract imposes an unreasonable obstacle to obtaining a legally enforceable obligation particularly where, as here, such competitive solicitations are not regularly held. . . . The Montana Rule is therefore inconsistent with PURPA and the Commission's regulations implementing PURPA to the extent that it offers the competitive solicitation process as the only means by which a QF greter than 10 MW can obtain long-term avoided cost rates.

Hydrodynamics Inc., 146 ¶ 61193 (March 20, 2014), ¶ 32-33. We therefore do not support the use of a competitive solicitation for acquisition of QF resources.

V. SHOULD THE IRP PROCESS BE USED TO UPDATE AVOIDED COSTS?

To the extent that the IRP process is used to set and constrain utility costs, then it is appropriate to use it to set avoided costs for QFs, since the latter are intended to be based on the former. However, the suggestion that the costs of energy efficiency, demand response, or other generation alternatives should be used to set the price for QF generation is opposed to the principles of PURPA. When avoided costs are set, the FERC rules require that specific factors are taken into consideration. See 18 CFR 292.304(e). These factors include elements that are not applicable to energy efficiency or demand response programs. These programs are therefore not an "apples to apples" comparison for setting utility avoided costs for payment to QFs. Furthermore, the utilities in Michigan have state-mandated targets for energy efficiency and other energy waste reduction programs, so some percentage of utility available capacity is effectively reserved for these programs. To state the obvious, such programs are not eligible for QF status under PURPA. Thus, basing QF pricing on programs that QFs are barred from participating in would be contrary to the requirements of PURPA.

On the other hand, where a QF can meet a state-mandated requirement, then the costs of meeting that requirement should be represented in the "avoided costs" of the utility. The FERC has commented as follows on this situation:

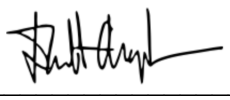
> [I]f a state required a utility to purchase 10 percent of its energy needs from renewable resources, then a natural gas-fired unit, for example, would not be a source "able to sell" to that utility for the specified renewable resources segment of the utility's energy needs, and thus would not be relevant for determining avoided costs for that segment of the utility's energy needs. Stated more generally, SoCal Edison supports the proposition that, where a state requires a utility to procure certain percentage of energy from generators with certain characteristics, generators with those characteristics constitute the sources that are relevant to the determination of the utility's avoided cost for that procurement requirement.

S. Cal. Edison Co., 133 FERC ¶ 61,059 (2010) at ¶ 27 (emphasis added).

VI. WHAT IS THE RELATIONSHIP OF QF CAPACITY TO PA 295 OR CUSTOMER-REQUESTED GREEN ENERGY PROGRAMS?

To the extent that QFs are eligible to participate in PA 295 or other green energy programs, then they should be considered an option when resources are being considered for those programs. For instance, when a utility is considering how it will meet its renewable energy requirements, it would be reasonable to expect it to consider whether and how QFs could help it meet those requirements by purchasing renewable energy credits from QF generators. Since utilities have a purchase obligation from these facilities with respect to their energy and capacity, and since many of them can offer renewable energy credits to the utility, it would be reasonable and prudent for the utility to evaluate them as a source for meeting their renewable energy requirements.

Respectfully submitted,



March 19, 2018

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