DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA

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IN THE MATTER OF Inquiry by the Montana Public Service Commission into its Implementation of the Public Utility Regulatory Policies Act of 1978	))))	REGULATORY DIVISION DOCKET NO. N2015.9.74

COMMENTS OF THE MONTANA CONSUMER COUNSEL

I. BACKGROUND.

On September 24, 2015, the Montana Public Service Commission (Commission) issued a Notice of Inquiry and Opportunity to Comment regarding its review of its implementation of the Public Utility Regulatory Policies Act of 1978 (PURPA). The Commission initiated this proceeding as the result of its denial of the Application of NorthWestern Energy for adjustment of its tariff rates for qualifying facilities under PURPA in Order No. 7338b, issued May 4, 2015, in Docket No. D2014.1.5.

In Order No. 7338b, the Commission explained that it was concerned that NorthWestern's failure to support its avoided cost proposal with a comprehensive, long-term planning analysis, based on its actual resource portfolio, left the Commission without sufficient evidence to re-calculate avoided costs. Order No. 7338b at ¶ 20. The Commission also stated that "NorthWestern does not appear to have made any substantial progress toward evaluating current wind integration requirements or planning for future requirements" (*id.* at ¶ 25) and that Northwestern had not demonstrated that costs for wind integration exceeding those set forth in its current rates would be just and reasonable (*id.* at ¶ 26). The Commission stated that, in light of changes in NorthWestern's generating portfolio (and notably the acquisition of approximately 439 MW in hydroelectric capacity from PPL Montana under authorization granted in Order No. 7323k in Docket No. D2014.12.85), that it would convene this docket in order to "gather information, conduct roundtable discussions and review its implementation of PURPA" (*id.* at ¶ 28).

The Commission's Notice of Inquiry and Opportunity to Comment, issued September 24, 2015, invited comments on its implementation of PURPA, including the five general issues identified in Order No. 7338b at ¶ 28:

> (1) Methods for estimating avoided costs; (2) standard rate design, including technology-specific rates, contract length, levelization, performance-based rate adjustors, and standard contracts; (3) market price forecasting methods; (4) resource capacity values; and (5) requirements for creating a "legally enforceable obligation" under PURPA.

The Commission also invited the attention of parties submitting comments to the specific questions developed in its Staff memorandum issued August 11, 2015 in this docket.

II. GENERAL COMMENTS

The Commission's PURPA regulations (ARM §§ 38.5.1901-38.5.1908) generally adopt the PURPA regulations of the Federal Energy Regulatory Commission ("FERC"), which appear at 18 C.F.R. Part 292. Section 210(b) of PURPA (16 U.S.C. § 824a-3) and Section 304(a) of the FERC's PURPA regulations (18 C.F.R. § 292.304(a)) require that rates for purchases from qualifying facilities shall: "(1) be just and reasonable to the electric consumer of the electric utility and in the public interest, and (2) not discriminate against qualifying cogenerators and qualifying small power producers." The first of these regulatory requirements – that PURPA rates be just and reasonable to the consumer – is too rarely emphasized in discussions of avoided cost determination, when it ought to be foremost in the Commission's consideration in conducting its inquiry in this proceeding.

The FERC's PURPA regulations, which the Commission implements through its own PURPA regulations in ARM §§ 38.5.1901-38.5.1908 and through its decisions on various PURPA issues (including the determination of avoided cost), "afford state regulatory authorities . . . great latitude in determining the manner of implementation" of FERC's PURPA regulations. *Small Power Production and Cogeneration Facilities: Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978*, Order No. 69, FERC Stats. & Regs. ¶ 30,128, at 30,891-30,892 (1980). The Commission's present inquiry represents an opportunity to use that latitude to restore a focus on the justness and reasonableness of PURPA rates to electric consumers.

The policy questions raised by the Commission in this docket generally concern risk, uncertainty, and the importance of holding ratepayers harmless for policy decisions regarding resource acquisition. While broad approaches and concepts are properly addressed in a policy docket, it is inappropriate, generally, to discuss specific rate design implementation and methodologies outside of a fact driven contested case context. Many variables are in question in any given fact scenario, and it would be premature for the Commission to attempt a theoretically pure but factually untethered approach to implementing the requirements of PURPA. Below are some specific responses to the identified issues.

III. MCC RESPONSES TO COMMISSION ISSUES.

The MCC provides the following specific responses to the questions posed.

Issue 1: Methods for Estimating Avoided Costs

MCC Response:

Any methodology applied in estimating avoided costs should address risk, uncertainty, and most critically the hold harmless requirement for ratepayers. Electricity consumers should be economically indifferent as to choices between specific resources or types of resources. Certainly, NWE's generation portfolio has changed significantly over the years and those changes should be taken into account in analyzing avoided costs and resource acquisition.

With respect to utilizing models to determining appropriate costs, all models are based on assumptions. When models are not transparent, replicable and easily challenged, they are not reliable in terms of the output derived from them. MCC offers some specific comments on PowerSimm below, as it has in earlier proceedings,

These observations, in turn, frame a larger issue that the Commission Staff has articulated indirectly in its August 12 Memorandum: In an environment in which price formation is driven to a greater extent by market forces than by traditional cost of service regulation, is it reasonable to subject ratepayers to the risk of prices for twenty-five year QF contracts where avoided cost is determined on a cost-of-service basis? Put another way, the Commission should give serious consideration to mitigating consumer risk by shortening the duration of QF contracts. A shorter QF contract term – on the order of five to seven years, possibly shorter – significantly mitigates the risk to consumers of predictive inaccuracy of models and underlying assumptions by shortening the length of time to which consumers will be subject to prices determined on the basis of forecasts and projections that have been superseded by the realities of the marketplace. At the same time, the "must-purchase" aspect of the PURPA regime (ARM § 38.5.1903) ensures that the expiration of a QF purchase contract does not eliminate the QF's ability to earn compensation for the sale of its output at rates that are just and reasonable at the time.

Once embedded in a contract (or other legally enforceable obligation), the rates received by a QF are generally not subject to regulatory review because FERC's PURPA regulations exempt QFs from state rate regulation (18 C.F.R. § 292.602(c)(1)). There is thus no opportunity during the term of a QF contract to "adjust" the rate in order to reflect changed economic realities at variance with the assumptions underlying the avoided cost rate set at the time the contract was executed. By shortening the duration of a long-term PURPA contract, the Commission would enhance the opportunity to narrow gaps between old avoided cost rates and contemporary economic realities.

The Idaho Public Utilities Commission has recently adopted this approach with respect to what it calls "IRP-based contracts" in its Order No. 33357, issued August 20, 2015. *In the Matter of Idaho Power Co.'s Petition to Modify Terms and Conditions of PURPA Purchase Agreements*, Order No. 33357, 2015 WL 5002133, 2015 Ida. PUC LEXIS 108 (August 20, 2015). The Idaho Commission: (1) reduced the standard term of IRP-based PURPA purchase agreements to two years; (2) allowed case-by-case review of contracts for a longer term; and (3) reasoned that the PURPA must purchase obligation will operate to ensure that QFs continue to earn compensation following the expiration of initial contracts. MCC commends this approach to the Commission, as it greatly simplifies a number of complicated questions raised in the Notice of Inquiry in this proceeding.

<u>Responses to Staff Questions</u>:

a) **What methods are reasonable for the Commission to use to estimate NWE's long-term avoided costs and set rates for small and large QFs? Why are those methods preferred?**

b) **What methods should the Commission refrain from using to estimate NWE's long-term avoided costs and set rates for small and large QFs. Why should those methods be avoided?**

The primary point of differentiation, as Staff's question correctly recognizes, is between small and large QFs. FERC's PURPA regulations require the establishment of standard rates only for qualifying facilities with a design capacity of 100 kilowatts or less (18 C.F.R. § 292.304(c)), but permit the use of standard rates for larger facilities. This Commission currently allows standard rates for qualifying facilities with up to 3 MW design capacity. Limiting the availability of standard rates lowers costs and risks to consumers, and the only absolute endpoint for limiting the availability of standard rates is the 100 kilowatt design capacity limit established in FERC's PURPA regulations.

Subject to the foregoing observations, there is relatively less harm in using a more generous avoided calculation methodology to set rates for smaller qualifying facilities than there is in using such a methodology to set rates for larger qualifying facilities. Allowing the use of proxy, or surrogate, avoided resources – typically a simple cycle combustion turbine – to set standard rates provides a generally lower capacity payment where warranted and a higher energy rate. This approach may not produce an unimpeachably accurate calculation of true avoided cost, but limiting its application to small QFs causes relatively little economic harm to consumers. The use of standard proxy resource rates in connection with larger QFs is contraindicated precisely because it amplifies the inaccuracy of the methodology and increases the harm incurred by consumers as a result of that inaccuracy.

In the case of larger QFs, the preferable pathway to establishing avoided cost rates is actual competitive solicitation. There is simply no substitute for the discipline of a functional market on pricing behavior.

Where competitive solicitations fail, some version of the differential revenue requirement rate methodology, which effectively calculates the differential in the purchasing utility's revenue requirement with and without the marginal resource represented by the QF, may be useful. However, this methodology needs to be used with extraordinary caution in order to ensure that the analysis involved – typically, a long-term stochastic forecast of costs for the purchasing utility – is not subject to both conscious and unconscious manipulation that inevitably tends to bias the analysis. And its use must account for the inevitable cost and risk shifting to ratepayers discussed below.

c) Does NWE's acquisition of the PPLM hydroelectric resources affect which methods are best suited for estimating NWE's avoided costs? If so, how?

As the Commission recognized in Order No. 7338b at ¶¶ 20-21, 28, the impact of NorthWestern's acquisition of 439 MW in hydro capacity at least requires a completely revised long-term resource planning analysis. If a correctly performed analysis actually indicates that NorthWestern does not anticipate a capacity need until 2033 (again, referring to Order No. 7338b at ¶¶ 20-21), there appears to be a substantial question as to the nature and extent of any near- or intermediate-term requirement for capacity on the NorthWestern system. To put the issue another way, it appears questionable whether and to what extent there is any capacity cost to be avoided over a meaningful forecast horizon. This in turn calls into question the usefulness of conducting a power cost simulation over a fifteen to eighteen year horizon to establish rates for the acquisition of resources that the system does not require. *See City of Ketchikan, Alaska*, 94 FERC ¶ 61,293 at 62,061 (". . . there is no obligation under PURPA for a utility to pay for capacity that would displace its existing capacity arrangements" and "there is no obligation under PURPA for a utility to enter contracts to make purchases which would result in rates which are not 'just and reasonable to electric consumers of the electric utility and in the public interest' or which exceed 'the incremental cost to the electric utility of alternative electric energy'").

MCC infers that this concern was the root of at least some of the Commission's discomfort with NorthWestern's evidentiary presentation that resulted in Order No. 7338b. Without any reliable identification of system requirements, there is no trustworthy basis for determining avoided cost rates. This is certainly true for capacity costs. It may also be true in this case for energy costs, as the significant amount of hydroelectric capacity suggests that avoided energy costs may be limited to a significant extent by system reliance on run-of-the-river hydro resources.

d) Is NWE's PowerSimm planning model suitable for applying differential revenue requirements and component/peaker methods? What, if any, concerns would you have with using PowerSimm to estimate avoided costs using these methods?

e) If PowerSimm is suitable for applying differential revenue requirements and component/peaker methods, does the model need to make use of optimal capacity expansion planning capabilities in order to reasonably calculate applicable costs? Why or why not?

Staff's inquiry concerning PowerSimm raises questions that are better resolved on an evidentiary record, rather than in a policy docket such as this. PowerSimm and its application in specific cases have been the subject of contested proceedings previously, and it should be expected that similar issues will (and should) arise in future contested cases. For this reason, the Commission should refrain in this proceeding from any abstract evaluation of any specific production cost model.

MCC has observed in previous cases that PowerSimm is only a tool which, as is the case with all tools, depends for its usefulness and accuracy on the skill and purpose with which it is deployed. The same observation pertains to Staff's questions on this point. MCC invites the Commission's attention to Commissioner Kavulla's comments on PowerSimm in his partial dissent in Order No. 7323k (slip op. at 26-28). The real question is whether, if the Commission is going to continue to base avoided cost rates on the use of this (or any other) particular tool, it ought to consider requiring NorthWestern to fund an analysis performed under the Commission's supervision and direction by an independent consultant for purposes of evaluating avoided cost. MCC recommends that the Commission consider and evaluate this approach, and also consider a mechanism to allow vetting of the formulation of stochastic analyses of cost projections and analytical inputs into those analyses by MCC and other interested parties. This would ensure improved levels of transparency and auditability in PURPA rate formulation before this Commission.

<u>Issue 2: Standard rate design.</u>

Issues that should be considered in assessing the propriety of implementing a general policy around which fact specific cases may be analyzed should include first and foremost the impact on consumers. Contract length should not be used to protect QFs or to make them viable. Rates should be recalculated on a not less than three year basis to ensure that consumers are paying the cost of the resource, and not an inflated resource cost based on levelized rates that do not reflect actual costs.

Standard rates should not reflect the avoided costs levelized for the length of the contract because this inappropriately shifts risks to consumers. Long term contracts shift risks to consumers by locking consumers in to paying rates set on the basis of inherently undependable projections of future costs. There are too many variables in play for the Commission to approve a standard power purchase agreement, although the Commission may wish to consider evaluating – on a more complete record developed at a later point in this inquiry – whether specific terms of a QF purchase agreement could reasonably be standardized. Generally, the material terms of QF purchase agreements should be negotiated on a case-by-case basis, subject to Commission review of the reasonableness of the purchase arrangement prior to its taking effect.

a) Should the Commission set separate standard rates for small solar, hydroelectric, and/or other eligible generating technologies that reflect the specific generating characteristics of those technologies? Why or why not?

As MCC indicated in its opening observations, the operative inquiry as affecting eligibility for standard rates should be the size of the qualifying facility rather than specific generation attributes. Generally, protecting consumers from excessive avoided cost rates requires limiting the availability of standard rates to the minimum requirements of FERC's PURPA rules (18 C.F.R. § 292.304(c)). Affording standard rates to any qualifying facility larger than 100 kilowatts in design capacity imposes unnecessary costs on consumers, as a general matter. It may be permissible in principle for states to distinguish among resource characteristics in establishing purchasing requirements for its public utilities.[1] That does not make such a course of action prudent or consistent with

[1] *See So. Cal. Edison Co.*, 70 FERC ¶ 61,215 at 61,676, *reconsideration denied*, 71 FERC ¶ 61,269 (1995).

the public interest in all circumstances, or even a prudent course of action. Complicating the PURPA procurement process by attempting to differentiate between different types of generating technologies or environmental attributes appears unproductive, in light of Montana's limited resource needs and areas of PURPA administration in Montana that have more immediate and pressing needs for the Commission's attention and resources.[2]

b) What contract length is sufficient to enable a viable QF project to obtain financing?

c) Does a 25 year standard rate contract length impose undue forecast risk on consumers? If so, why?

d) Comment on the reasonableness of shortening the maximum contract length in NWE's standard QF tariff schedules.

e) To what extent should the length of a standard rate QF contract reflect the economic life of alternative resources NWE is planning to acquire?

MCC believes that almost any reasonable contract length is sufficient to support the financing of a viable QF project, in light of the fact that the purchasing utility is subject to an ongoing must-purchase obligation under ARM § 38.5.1903 following expiration of the contract. The purchase is bound to be renewed; the issue is at what price. In light of the regulatory requirement that rates be set either at a negotiated value or at avoided cost, the future revenue stream of the project following the initial contract term (assuming here a five- to seven-year term, as recommended above) may be undefined, but is unquestionably ample to support financing.

A 25-year standard contract duration imposes unjustifiable financial burdens on consumers in most cases because the forecasted values on which the contract price is based inevitably turn out to be incorrect. Consider a hypothetical situation in which long-

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[2] A legislative requirement or policy to promote one specific generating technology over another is usually the predicate for this kind of differentiation. That kind of legislative directive, in the case of the California Legislature's statutory policy promoting the adoption of distributed combined heat and power resources, led the FERC to revisit the question whether PURPA *permits* a state PURPA implementation program to afford differential treatment to specific types of resources in certain circumstances. *See Cal. Pub. Utils. Comm'n*, 132 FERC ¶ 61,047 at PP 64-72, *order on clarification and dismissing reh'g*, 133 FERC ¶ 61,059 (2010), *reh'g denied*, 134 FERC ¶ 61,044 (2011). In the absence of a state legislative mandate for such differential treatment, the complexity of the questions involved and the debatable value of the proposition furnish strong practical reasons not to pursue it.

term resource procurement was irrevocably authorized at the peak of wholesale power prices in the Western United States in early September 2008, based on an anticipation that wholesale power pricing trends experienced over the preceding four or five years furnished a reasonable benchmark for asset valuation. Experience now shows that incurring significant future costs on the basis of that kind of projection, just before the start of the Great Recession and the collapse of power prices in the Western United States, would be a paradigmatic illustration the risks of making long-term commitments based on power price forecasts that are inevitably subject to changes unforeseen at the time the projection is made and therefore invariably incorrect. Long-term forecasts are inherently uncertain. Estimates can be made of that uncertainty via Monte Carlo analysis, but the underlying probabilities are unknowable. Translating long term forecasts into contractual fixed rates may provide great value to QFs, but the stratagem imposes risks and uncompensated costs on ratepayers -- the longer the contract term, the greater the risk transfer and cost imposition. This can be mitigated by shorter contract terms.

MCC believes that an approach comparable to that taken by the Idaho Public Utilities Commission in its Order No. 33357, *supra*, is absolutely reasonable and the most direct path to a rational PURPA program in Montana. MCC is unaware of any reason why the economic life of alternative resources NorthWestern plans to acquire should be viewed as relevant to the appropriate duration of a standard offer contract.

f) Should standard rates reflect avoided costs levelized for the length of the contract? Why or why not?

Levelized rates do not contribute to the justness and reasonableness of QF rates to electric consumers. Historically, the use of levelized rates represented a means to accelerate QF project cash flow to developers, while making the levels of payment in the later years of a QF contract appear less onerous or expensive than would have been the case without levelization. The use of levelized rates simply masks the problems inherent in the inherent unreliability of utility production cost forecasts over periods in excess of approximately five years. It would be far preferable for the Commission to shorten the length of PURPA contracts to a period – five years would be appropriate, at least initially – over which the utility production cost forecast used to determine avoided costs could be deemed reliable. On that basis, the rationales that typically support the use of levelized rates simply have no relevance. Developers earn that to which they may be entitled on a more or less contemporaneous basis, and consumers pay a rate more closely tied to a reliably predicted reality in utility operations.

g) Montana law requires the Commission to encourage long-term contracts for purchases of electricity by utilities from QFs. Mont. Code Ann. § 69-3-604(2). How should the Commission interpret or define "long-term"?

Section 69-3-604(2) provides in full that "Long-term contracts for the purchase of electricity by the utility from a qualifying small power production facility must be encouraged in order to enhance the economic feasibility of qualifying small power production facilities." The text of the statute leaves the development of a precise formulation of the meaning of the expression "long-term" to the Commission. The operative consideration embedded in the statutory is the purpose "to enhance the economic feasibility of qualifying small power production facilities." In considering a contract duration or durations that would "enhance the economic feasibility" of qualifying small power production facilities, the Legislature recognized that the Commission is also bound by various other obligations incumbent on Montana's implementation of the FERC's PURPA regulations.[3] These include, as previously observed, the requirement that rates for QF purchases be just and reasonable to electric consumers and consistent with the public interest, as required by Section 210(b)(1) of PURPA and 18 C.F.R. § 292.304(a).

The statutory text and context of Section 69-3-604(a) compel the conclusion that the phrase "long-term contracts" be interpreted in such a way as to accommodate all of the foregoing considerations. Similarly, the Legislature's directive to "enhance the economic feasibility" of small power production facilities requires that the notion of economic feasibility be examined by the Commission both from the perspective of QF developers and electric consumers who pay the resulting rates. In other words, "economic feasibility" is a neutral proposition as between QF developers and owner, on the one hand, and electric consumers who ultimately pay the rates that support the QFs on the other hand. Based on this analysis, the MCC's recommendation that the Commission shorten the duration of PURPA contracts to five-year to seven-year term, or less, is consistent with the directive of Section 69-3-604(a), MCA.

h) Should standard rates include performance standards and automatic rate adjustments for failure to meet the standards? Provide any specific recommendations you have for such standards and rate adjustments.

i) Should the Commission approve a full standard power purchase agreement? Why or why not?

Non-market incentives and penalties can prove to be attractive but dangerous tools, because they tend to focus the effort and attention of a party on which they operate primarily on the attainment of the bonus or the avoidance of the punishment. This tendency can, in turn, cause the overall objective of the performance of the contract to suffer. For this reason, incentives and penalties need to be carefully evaluated and modulated in order to ensure that their presence in a contract (or other purchase arrangement) does not divert attention from other desirable aspects of performance. In short, the question of performance standards and automatic rate adjustments should be deferred to a more thorough evaluation of (a) desired outcomes and behavior, and (b) comparable measures that experience has proven to be effective in other jurisdictions.

Montana's experience with QF contracts may not be sufficient at this point to support the development and implementation of a full standard power purchase agreement. Again, it would be prudent to identify comparably situated jurisdictions and survey the experience of those jurisdictions with the use of standardized QF purchase contract terms before embarking on the development of such an instrument for use in Montana.

Issue 3: Market price forecasting methods

Any policy the Commission adopts regarding forecasting methodology should ensure that forecasts are theoretically sound, transparent and robust. Stochastic and probabilistic forecasting methodologies all have limited usefulness in light of the inherent

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[3] Section 69-3-601 through 69-3-604, MCA, were intended by the Legislature to be temporary measures, subject to automatic repeal in the event of the repeal of PURPA.

unpredictability of future phenomena that will significantly impact prices and costs. Consider that, over the past seven years, the electric utility industry has experienced two phenomena – (1) the Great Recession of 2008-2009, and the resulting reduction in the cost of capital; and (2) the emergence of significant domestic supplies of shale gas, with the resulting reduction in fuel costs – which turned almost every production cost projection made during the years leading up to 2008, regardless of how rigorously conducted, into an exercise in precision without accuracy. In a market-driven system, the one overarching certainty is the presence of unquantifiable uncertainty. On a more basic level, simple averages of multiple forecasts to assemble one hybrid individual forecast are inappropriate where they fail to address outlier projections capable of skewing the results, even on an average basis.

As stated previously in these comments, the most certain way to compensate for the inherent limitations of price forecasting is to shorten the duration of QF purchase contracts. By shortening contract duration, subject to the ultimate discipline of the PURPA must-purchase obligations, the adverse impact of inevitable forecasting errors on electric consumers will at least be mitigated by reasonably timely adjustment to contemporaneous economic reality.

a) Is the Commission's current practice of blending forward market price information and EIA's long-term reference case forecasts reasonable? If not, what changes do you recommend and why?

b) Should the Commission consider a range of possible future prices (as opposed to a single price forecast) when estimating avoided costs and setting rates? If so, what sources should the Commission look to for alternative price forecasts and how should the Commission treat the multiple forecasts in the rate setting process (e.g., should they be averaged or weighted)?

c) Since forward market prices can change, sometimes significantly, over short periods of time, would an average of recent forward price information be preferable as a starting point for developing a price forecast than a "snapshot" taken at a particular point in time? Why or why not?

f) Is a forecast of regional (e.g., Mid-Columbia) market prices, alone, a reasonable basis for standard avoided cost rates? Why or why not?

MCC's responses to these questions all appear in its introductory comments with respect to this issue. Generally speaking, a broader forecast perspective may be less inaccurate than a narrow one. However, none of the hypothetical approaches suggested in Staff's questions (a) through (c) on this issue really offers material mitigation for the risks of price and production cost forecast inaccuracy to electric consumers. Market-based pricing, through Commission-directed and Commission-supervised public procurement is a far preferable alternative. Failing that alternative, the shorter the duration of a purchase contract based on inherently undependable forecasting, the better. There is no reliable justification for basing standard avoided cost rates on regional market prices, because regional forward price curves are based more or less on the same kinds of stochastic and probabilistic forecasting tools that NorthWestern (or another utility) would use to predict future production costs and market prices. In addition, the use of regional forward price curves to set avoided cost appears, at least on its face, to be inconsistent with the general requirements of FERC's PURPA regulations (implemented through ARM §§ 38.5.1901-38.5.1906) that PURPA rates be based either on negotiated values or on the avoided costs of the purchasing utility.

The primary justification for basing standard avoided cost rates on regional market forward price curves is that it would avoid the cost and stress of evaluating a more localized forecast based on comparable data and using comparable tools. The conceptual limitation remains the same, and the saving in administrative resources does not seem to represent a sufficiently significant benefit to justify the approach.

d) Is the Commission's current approach to accounting for estimates of the incremental costs of CO2 emissions in long-term standard rates for small QFs reasonable? If not, why and how should the approach be modified?

e) Should NWE receive all or a portion of the renewable energy credits produced by a QF if the purchase rate includes the incremental cost of CO2 emissions?

The basic problem with estimating the incremental costs of carbon dioxide emissions in long-term standard rates is that there currently is no empirically sound basis available for the estimates. This may change with the pending implementation of the EPA's Clean Power Plan, but the development of a sound empirical basis for estimating incremental costs of carbon dioxide emissions remains to be realized. In the meantime, the estimation process is inherently speculative, and fails to provide any verifiable benefit to the consumers who pay the resulting costs.

Recognizing that entitlement to ownership of renewable energy credits has been a matter of some controversy,[4] it is clear that payment for the environmental attribute in a QF purchase contract entitles the purchaser to ownership of any resulting renewable energy credits. Any contrary view is impossible to reconcile with the requirement of Section 210(b) of PURPA and Section 304(a) of FERC's PURPA regulations (18 C.F.R. § 292.304(a)) that PURPA rates must be just and reasonable to electric consumers.

<u>Issue 4: Resource capacity values</u>

There are two fundamental problems with assigning capacity values to intermittent (or variable energy) resources such as wind, solar and run-of-river hydroelectric generation. First, there is limited empirical data available to support a reasonable choice of a capacity value for such resources that reflects a dependable contribution to system capacity sufficient to justify the imposition of a payment for that capacity on consumers. Second, there is also very limited empirical data available concerning the cost of "integrating" those resources – meaning, primarily, the cost of providing the regulation capacity required to manage Area Control Error when those resources become unavailable, and the cost of Energy Imbalance service to compensate for the mismatch between load and generation over an appropriate dispatch interval (historically, the interval has been hourly; more recently, there has been movement toward using intra-hourly dispatch to mitigate the cost of integrating variable energy resources). Absent reliable empirical data to support the calculation of a capacity value, the estimation of such a value relies on projections and estimates that are inherently unreliable and

[4] *See Morgantown Energy Assoc.*, 140 FERC ¶ 61,223 at PP 18-26 (2012) (finding "inconsistent with PURPA" the West Virginia Public Service Commission ruling that transfer of ownership of renewable energy credits is inherent in the payment of PURPA rates); *American Ref-fuel Co.*, 105 FERC ¶ 61,004 (2003), *reh'g denied*, 107 FERC ¶ 61,016 (2004), *appeal dismissed*, *Xcel Energy Servs., Inc. v. FERC*, 407 F.3d 1242 (D.C. Cir. 2005) (finding that payment of avoided cost rates

typically biased against the interests of electric consumers in not paying more than necessary for their electricity.

At the outset, the Commission is not required – by PURPA or otherwise – to assign or impute a capacity value to variable energy resources. *Exelon Wind I, LLC v. Nelson*, 766 F.3d 380, 399-400 (5th Cir. 2014). The Commission may wish to revisit its choice to afford some capacity value to these types of resources in the context of this inquiry.

a) Is the current practice of setting standard rates for wind QFs based on an assumed five percent capacity value reasonable? If not, why?

The Commission's current practice of using an assumed capacity value equivalent to five percent of nameplate rating is the result of a decision based on what the Commission considered the best evidence available to it in Docket No. D2012.1.3. Order No. 7199d at ¶¶ 52-55 (November 20, 2012). Prior to Order No. 7199d, the Commission had assigned various capacity values of between 15 and 38 percent of nameplate rating to QF wind resources (*id.* at 46). The Commission's practice is "reasonable" in the sense that it represents a litigated decision, taken after full consideration of an evidentiary record, and is no longer subject to appeal. This does not necessarily establish that the use of a five percent capacity factor has a sound empirical basis.

The basic problem is that site-specific meteorological conditions affect the availability of wind resources in such a way as to make a generic approach to capacity rating of these resources largely unworkable – or at least unreliable. The impact of site-specific, or at least area-specific, meteorological conditions on a "capacity" value for wind resources may make it preferable to undertake a case-by-case evaluation of available capacity over time. This kind of approach would be administratively complex, and may be of limited practical application (perhaps to larger wind resources). A more site-specific capacity evaluation process for wind resources would certainly be facilitated by the use of shorter QF purchase contracts.

b) Can the Commission set reasonable standard rates without calculating technology-specific capacity values using estimation methods such as effective load carrying capability or exceedance? If so, how? Are there

under PURPA does not effect a transfer of ownership of renewable energy credits under existing PURPA contracts).

reputable sources of estimates of average capacity values for various generating technologies that, although not specific to NWE's system, could be used for setting standard rates? If so, please identify such sources.

c) Should QFs, whether or not they are eligible for standard rates, be required to contractually commit to provide a quantity of capacity in order to receive a capacity payment, with penalties or rate reductions if delivered capacity falls short? How could the Commission align such a requirement with FERC rules requiring consideration of the aggregate value of QF capacity? See 18 C.F.R. § 292.304(e).

The more generic issue of attempting to assign capacity values to other types of variable energy resources raises problems comparable to the attempt to assign such values to wind resources. MCC is not aware of any reliable substitutes for site-specific observations and long-term data for variable energy resources of any type – including wind, solar and run-of-river hydroelectric – although many have attempted this exercise. The California ISO, for example, assigns capacity values to solar generating facilities as part of its implementation of the California Public Utilities Commission's Resource Adequacy Assurance ("RAA") requirements. As far as MCC is aware, those values are at least region-specific and are probably not useful for developing a capacity value for solar resources in Montana.

The better answer to Question (c) would be to forego the exercise of arguing about capacity values and simply adopt the Texas solution of limiting variable energy resources to as-available payments. As the question suggests, the requirement of a contractual commitment to capacity supply, with corresponding penalties, would likely be found "inconsistent with PURPA" by the FERC.

d) Can the Commission set reasonable QF rates absent technology-specific information regarding integration requirements and costs? If so, how?

e) Are there reputable sources of estimates of the average integration requirements for various generating technologies that could be used for setting standard rates? If so, please identify such sources.

The Commission can set reasonable QF integration rates. The problem is less one of "technology-specific information" and more a matter of requiring the requisite studies and analyses either be (1) performed by regulated utilities subject to the Commission's supervision and oversight, and with input and participation from MCC and other parties appropriately representative of the consumer interest, or (2) performed by independent consultant's engaged by the Commission and financed by the regulated utilities, again with input and participation from MCC and other parties appropriately representative of the consumer interest. MCC is not aware of any reliable sources of estimates of integration costs for variable energy resource generating technologies.

Issue 5: Requirements for creating a "legally enforceable obligation"

As noted in Staff's memo, the Commission established a "bright-line test" for establishing the existence of a "legally enforceable obligation" ("LEO") in Order No. 6444e at ¶ 47 (Docket No. D2002.8.100, June 4, 2010):

> To establish an LEO, a QF must tender an executed power purchase agreement to the utility with a price term consistent with the utility's avoided costs, with specified beginning and ending dates, and with sufficient guarantees to ensure performance during the term of the contract, and an executed interconnection agreement. The executed contract demonstrates an unconditional commitment. If the utility also executes the contract, the utility would be able to enforce the obligations undertaken by the QF. Interconnection expenses may be so high as to derail an otherwise feasible project. Only by acknowledging and agreeing to an interconnection agreement can a QF demonstrate that it is prepared to proceed despite any interconnection obstacles. Further, an interconnection agreement requires that a QF have sufficiently defined its project and made adequate progress that the project would be more than a mere speculative, paper proposal.

The Commission's existing requirements for establishing an LEO are adequate. Speaking more broadly, it is possible to view an LEO as a species of contract implied in fact,[5] and the requirements established by the Commission in Order No. 6444e are both

[5] *See* Section 28-2-103, MCA; *See also Cartwright v. Joyce*, 155 Mont. 478, at 484 (Mont. 1970) (finding the existence and terms of and implied contract are manifested by conduct, "i. e. a contract implied in fact"). The elements required to establish an implied contract are: identifiable parties, consent, a lawful object, and consideration. *C B & F Dev. Corp. v. Culbertson State Bank*, 256 Mont. 1, at 6 (Mont. 1992) (finding implied contract where bank gave loan to plaintiff and Bank accepted delinquent payments from plaintiff).

consistent with that approach and specific to the context of meaningful levels of commitment to providing an electric utility with power supply.

As to the other questions posed in Staff's memorandum, there is no inconsistency between the definitional elements of an LEO adopted by the Commission in Order No. 6444e and the regular operation of the Commission's competitive solicitation rules. The possibility of a QF "helping itself" to an LEO in the context of a competitive solicitation can be simply and straightforwardly avoided by requiring Commission approval of commitments resulting from a competitive solicitation as a condition of final acceptance of proposal, or a reservation of the right to reject proposals (again, subject to Commission review). In any case, the one requisite that MCC strongly recommends for determination of the existence of an LEO is requirement for an express finding by the Commission, on the basis of an evidentiary record in the event of dispute, that an LEO has been established.

Respectfully submitted October 23rd, 2015.

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