Meyer, Shaffer & Stepans, PLLP

Ryan Shaffer | ryan@mss-lawfirm.com
Robert L. Stepans | rob@mss-lawfirm.com
Ali Archual | ali@mss-lawfirm.com

October 23, 2015

VIA ELECTRONIC MAIL

Montana Public Service Commission
1701 Prospect Ave
P.O. Box 202601
Helena, MT 59601

psc_utilitycomment@mt.gov

Re: N2015.9.74 – PURPA Implementation

Dear Montana Public Service Commission:

Please find attached the comments from WINData, LLC and Crazy Mountain Wind, LLC in response to the Commission's request for written comments addressing implementation of PURPA.

Sincerely,

MEYER, SHAFFER & STEPANS, PLLP

Ryan Shaffer

cc: Greg Adams
Marty Wilde
Dave Healow

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

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

<u>Comments of Crazy Mountain Wind, LLC and WINData, LLC</u>

In response to the Montana Public Service Commission's ("MPSC" or "Commission") request for written comments addressing implementation of the Public Utility Regulatory Policies Act of 1978 ("PURPA"), Crazy Mountain Wind, LLC ("Crazy Mountain") and WINData, LLC ("WINData") hereby submits the following comments. Crazy Mountain and WINData agree with the MPSC that Montana's implementation of PURPA needs to be corrected. The current implementation provides a lack of clarity as to the rules that apply for projects over 3 megawatts ("MW"), which are not eligible for standard avoided cost rates. This lack of clarity has allowed NorthWestern Energy ("NorthWestern") to thwart any meaningful opportunity to contract under PURPA for projects over 3 MW. The intent of PURPA is to allow for cogeneration and small power production facilities (under 80 MW) utilizing a renewable fuel source to sell electric energy and capacity to a utility at the utility's avoided costs. If properly implemented, PURPA can both result in a more diversified energy supply portfolio with independent power producer ("IPP") facilities and provide a meaningful benchmark against which to hold NorthWestern in its own acquisitions of rate-based resources.

The comments below are organized in the order set forth in the questions posed to stakeholders in the Staff Memo, issued in this docket (N2015.9.74) on August 12, 2015.

1. Methods for estimating avoided costs

The Montana Supreme Court has explained: "PURPA requires large utilities to purchase energy from smaller qualifying facilities at rates that allow the small facilities to become and remain viable suppliers of electricity." *Whitehall Wind, LLC v. Montana Pub. Serv. Comm'n.*, 355 Mont. 15, 16-17, 223 P.3d 907, 908-09 (2010). The Federal Energy Regulatory Commission's ("FERC") regulations, which are adopted by ARM 38.5.1902(1), require state commissions to implement PURPA in a way that requires a utility to purchase energy and capacity from qualifying facilities ("QF") at the *full* avoided costs of the purchasing utility. *Amer. Paper Institute, Inc. v. Amer. Elect. Power Serv. Corp.*, 461 U.S. 402, 415-18 (1983). Additionally, both Montana law and FERC's rules require long-term contracts that contain forecasted avoided cost rates calculated at the time the QF obligates itself. M.C.A § 69-3-604(2); 18 C.F.R. § 292.304(d)(d)(ii).

Currently, NorthWestern asserts that the method for calculating standard rates does not apply to a QF over the 3MW size threshold, and therefore refuses to provide any long-term rates to such QFs. The Commission should clarify the correct methodology for NorthWestern to use in order to reduce disputes.

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?

The Commission's current method of calculating avoided costs for standard rates provides a reasonable approximation of the avoided costs to NorthWestern. Crazy Mountain and

WINData direct the Commission to the detailed testimony on this topic submitted by Greenfield Wind, LLC's expert witness, Dr. Don Reading, in D2014.4.43 (filed on July 24, 2014). If anything, this method underestimates the actual avoided costs in some circumstances, as discussed below.

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?

Crazy Mountain and WINData do not support adoption of a computer model methodology for *any* size QFs because that results in significantly increased transaction costs for both the utility and the QF. The flaws with a model method are explained in detail in Greenfield's D2014.4.43 testimony. To summarize here, the use of a computer model results in asymmetrical bargaining power that favors the utility because the utility selects the model, holds the model license, controls the inputs to the model, and has every incentive to underestimate the avoided costs. As evidenced in the Greenfield Wind D2014.4.43 proceeding, the model is a "black box" to the QF and even to the Commission and its staff. Minor changes to inputs and use of the model can have drastic impacts on the rates. In the Greenfield matter, the cost for use of the model was very high and actually resulted in significant contested issues the Commission had to resolve in discovery disputes. This was not an efficient way to calculate the rates because there are no guidelines or independent checks and balances.

If a model is adopted, the rates should be calculated by the Commission's staff in an open and transparent manner that allows the QF to participate in the rate calculation process without paying licensing fees. Additionally, Crazy Mountain and WINData strongly oppose any modeling methodology that does not capture the entire benefits conferred by the acquisition of the QF power, including the economic market sales opportunities that are enabled by the addition of the QF output. In the Greenfield docket, WINData and NorthWestern debated whether the computer method should be allowed to ignore the beneficial off-system sales that were enabled by the QF's supply of power to the utility. Although the parties in that case were able to bridge the gap between their positions and settle on an appropriate rate, they did so only after the expenditure of significant resources. The Commission should resolve these issues to prevent such disputes from occurring again in the future – which is sure to happen without clarification.

In addition, any computer methodology that is adopted should be applied to all future utility acquisitions of generation that will be placed in rate base. If the utility cannot demonstrate that its own generation resources provide output at the projected avoided costs to which QFs must agree, the resource should not be acquired.

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?

The methods used to evaluate QFs should not provide lower values than the methods that were used to evaluate and acquire the PPLM hydroelectric projects ("Hydros"). This question highlights the problem with allowing the utility to use an underestimate of avoided costs generated through a computer model to establish QF pricing and yet use a more reasonable methodology for pricing an *actual utility acquisition to be placed in rate base.* NorthWestern used a "discounted cash flow" analysis to justify the Hydros' acquisition, with a significant carbon-cost assumption added to the projected market rates. This generated a cost that justified the acquisition. However, NorthWestern has never recommended use of this method to calculate avoided costs for Greenfield, Crazy Mountain Wind or any other QF.

Additionally, the need to include the cost of avoided carbon risk to justify the acquisition cost of the PPL Hydro plants establishes another important point – that in today's market the value of a carbon-free resource includes that avoided carbon risk. PPL Montana was able to demand a higher price because of the carbon-free nature of the Hydros' generation. The economic risk and value associated with avoiding carbon regulatory costs is very much a part of today's electricity market for long-term resources. This is even more true today than at the time of the Hydros' acquisition because the Section 111(d) regulations are now final. Avoided cost rates should therefore appropriately consider this avoided regulatory cost for QFs that supply carbon-free electricity because that additional avoided cost is also a part of today's electricity markets.

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?

Crazy Mountain and WINData oppose the use of any proprietary computer model, especially without imposing the limitations indicated above. However, if a model is adopted and rates are calculated by the Commission Staff, the use of a differential revenue requirement method is preferable to the peaker method because, if correctly run, it will take into account the economic off-system sales enabled by the QF. The peaker method may not always take this factor into account.

Crazy Mountain and WINData do not have experience using PowerSimm and cannot comment on that model's capabilities. However, in the Greenfield proceeding, the costs required from WINData (Greenfield) to allow its use of the model were prohibitively high.

///

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?

If the model will use the differential revenue requirement method, it must include the planned additions to the resource stack in the model runs to capture the full avoided costs. Generally, the total costs of the next marginal unit will exceed those of the embedded resources, and ignoring the need to add marginal units during the time-frame for which QF rates are calculated will ignore the avoided costs of those units. However, Crazy Mountain and WINData have never operated the PowerSimm model, due to cost restrictions, and cannot comment specifically on the question without being provided more information.

2. Standard rate design

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?

The Commission already sets separate rates for small wind QFs to assign a lower capacity value to them as opposed to the avoided resource. Crazy Mountain and WINData are aware that Idaho and Oregon now offer resource-specific avoided cost rates to solar, wind, seasonal hydro (Idaho only), and base-load facilities. The theory behind accounting for the capacity value is to send a more accurate price signal to the QF by accounting for the QF's contribution to peak capacity needs. However, these capacity discounts for intermittent resources should not work to provide an incorrect, underestimate of the avoided costs.

The Commission should analyze whether the current method for wind facilities is actually resulting in a "double discount" for wind capacity value. After implementing a capacity discount similar to one applied to wind QFs in Montana, parties in Oregon recognized that the prior proxy method had *already included* an implicit reduction in overall capacity compensation to lower capacity factor resources simply by virtue of the fact that QFs are only paid per megawatt-hour ("MWh") of delivered electricity. The capacity component of rates were set based on the capacity costs of a gas-fired resource with a volumetric rate design that paid those capacity costs to the QF across all on-peak hours. However, the intermittent QF would receive just a fraction of those capacity dollars due to the fact that it does not deliver in all on-peak hours. In effect, under the prior proxy method, the QF was compensated for avoided capacity costs in proportion to the QF's annual *capacity factor* during all on-peak hours, rather than its actual contribution toward serving the few highest periods of demand on the grid.

Thus, when the Oregon Commission changed the methodology to include a reduced capacity payment to the QF on the QF resource's estimated *capacity contribution to peak load* (as Montana currently does for wind), it inadvertently created a double discount. Reducing the capacity costs by both (1) the capacity factor by paying only for delivered electricity, *and* (2) the capacity contribution to peak discount, creates a double discount below full avoided costs. There is extensive, persuasive evidence compiled by the Oregon Commission's staff on this point, in its efforts to correct the problem in the ongoing docket UM 1610 by providing a volumetric rate that is designed to compensate the QF over the course of a year for its contribution to the utility's peak capacity needs.[1] The MPSC should also correct this error that appears to exist in its rate calculation.

///

[1] *Oregon PUC Staff's Opening Testimony*, at p. 11-21, Or. PUC Docket UM 1610, Phase II (May 22, 2015), http://edocs.puc.state.or.us/efdocs/HTB/um1610htb11429.pdf .

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

Crazy Mountain and WINData support 25-year contract lengths with levelized rates. In today's market, this is the term length necessary to provide a realistic opportunity for the QF to finance the plant.

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

Crazy Mountain and WINData submit that undue forecast risk that exists from long-term QF contracts is little different from the risk that exists for utility-owned resources. The difference between the two, however, is that the QF provides a fixed price for the term of the contract, whereas a utility rate-based resource carries significant risk of increased costs associated with cost overruns and unexpected capital upgrades being passed onto the rate payer. For example, if the rate-based PPLM Hydros need to have unexpected capital upgrades in five years, those costs will almost certainly be passed onto rate payers, whereas a QF project must absorb its own costs and work within the contract prices it committed to in the power purchase agreement. While the utility may argue that the MPSC can place caps or limits on the rate-based costs at the time of acquisition, the reality is that the Commission will need to allow recovery of the utility's costs in many circumstances to preserve the financial integrity of the utility.

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

Crazy Mountain and WINData strongly oppose shortening the contract terms. As noted above, Montana law specifically directs the Commission to encourage long-term contracts for QFs. Shortening contract terms is a thinly veiled mechanism to kill independent power markets in the Northwest. It does not place the QF on the equal footing with the utility, which gets to rate-base a project for the life of the project.

Additionally, FERC's PURPA rules do not allow for contract terms that are so short that the QF will not be provided a fixed rate for energy *and* capacity calculated at the time it enters into a contract. 18 C.F.R. § 292.304(d). According to FERC's preamble to 18 C.F.R. § 292.304(d), the rule "is intended to prevent a utility from circumventing the requirement that provides capacity credit to the qualifying facility merely by refusing to enter into a contract with the qualifying facility." *Small Power Prod. and Cogeneration Facilities; Regulations Implementing Sec. 210 of the Pub. Util. Reg. Pol. Act of 1978*, FERC Order No. 69, 45 Fed. Reg. 12,214, 12,224 (Feb. 25, 1980). The preamble further explains that this rule "enables a qualifying facility to establish a *fixed contract price for its energy and capacity* at the outset of its obligation . . . ." *Id.* (emphasis added). The rule reflects "the need for qualifying facilities to be able to enter into contractual commitments" and "the need for certainty with regard to return on investment in new technologies" that only those long-term legally enforceable obligations could provide. *Id.* The current 25-year term meets these requirements, but shorter terms will not provide long-term rates for both energy and capacity.

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?

Crazy Mountain and WINData oppose setting QF contract terms based on the length of the resources that NorthWestern indicates it "is planning to acquire." Instead, the terms should be based on the length of commitments that NorthWestern has *actually* acquired, including the very long-term commitments recently made to the Hydros and the Spion Kop wind farm. It is easy for a utility to state in its IRP that it is currently only acquiring short-term resources, so as to offer extremely short-term QF contracts, and then to actually acquire long-term utility-owned resources without putting the resource out for a competitive solicitation. For the reasons stated above, the Commission should maintain the 25-year contract terms.

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

Crazy Mountain and WINData supports levelization of rates. Levelization of rates is important for financing purposes and is consistent with treatment of utility rate-based resources.

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"?

Crazy Mountain and WINData supports 25-year terms for the reasons stated above. In the utility industry, "long-term" obviously means terms that are at least 25 years. Utilities often rate-base facilities for much longer periods.

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.

Including performance guarantees is not necessary in a QF contract where the QF is only paid for delivered electricity. Unlike a rate-based utility plant, which imposes costs on the rate payers pay even when it is out of service or otherwise not delivering electricity, the rate payers do not pay the QF if the plant is not delivering electricity. In other words, the QF already has to perform to get paid at all. The QF has every incentive to generate and deliver as much output as possible. Additionally, if the contract includes pricing adjustments for deliveries during on-peak or off-peak times and days, the QF has an economic incentive to schedule outages during times when the power is worth less to the utility. Thus, the Commission should view any performance guarantee for QFs with significant skepticism because imposing unreasonable and punitive contract clauses are an easy way for the utility to ensure that the QF will be unable to finance and construct its facility.

NorthWestern typically includes mechanical availability guarantees ("MAG") in its power purchase agreements for wind facilities. A MAG requires the facility to be operational and ready to produce, regardless of availability of wind, during a certain percentage of hours in the month or year, such as 85 percent. If the independent power producer falls below the specified level of availability, it will owe the utility replacement cost damages for the cost of replacement energy that exceeds the cost the wind plant contracted to deliver for that month or year. Correctly drafted, a MAG can be a reasonable term if it includes standard industry carve-outs for manufacturer recommended maintenance and it provides for reasonable plant down-time to account for unforeseen events. If poorly drafted, a MAG can be a punitive provision that will eliminate the ability to secure financing for the plant.

However, NorthWestern often has also demanded a minimum annual net energy amount in addition to the MAG in its recent wind PPAs. This requires delivery of a minimum amount of specified output in each year. If the specified level of output is not delivered, the IPP will owe replacement cost damages. This is typically not a requirement in a wind PPA that also has a MAG. The MAG was developed to provide a substitute for the minimum output requirement for wind facilities where output can vary substantially from year to year due to wind variability from year to year. The minimum delivery requirement is an unnecessary and potentially punitive add-on, and NorthWestern should not be allowed to include it in wind contracts.

Additionally, the MPSC should closely monitor the types of clauses that NorthWestern has included, and proposes to include, in QF contracts in order to impose those same types of requirements on NorthWestern's recovery of costs from its own utility-owned resources.

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

Crazy Mountain and WINData support the development of a standard contract. Under the current implementation it is very easy for the NorthWestern to impose onerous and unreasonable clauses during negotiations. A standard contract could also provide the utility with the assurance of what terms are reasonable for purposes of its own rate recovery, which would provide significantly less controversy during negotiations with QFs.

It would be relatively easy for the Commission to develop a standard contract because there are models from other states, such as Oregon, and there are also template agreements produced and occasionally updated by the Edison Electric Institute and other industry groups. However, the contract must be developed in an open and transparent manner with the opportunity for comment by stakeholders. Simply allowing the utility to draft the standard contract without significant review by the Commission and stakeholders would result in a standard contract with unreasonable terms that will fail to properly implement PURPA.

Even if a full standard contract is not developed, the Commission should at least require NorthWestern to stop including illegal clauses in its contracts. The clauses that are currently the most unreasonable in PPAs proposed by NorthWestern are its curtailment provisions in wind contracts. NorthWestern invariably insists upon inclusion of an open-ended economic curtailment provision that is simply not legal under FERC's PURPA rules for a fixed-rate contract. In *Pioneer Wind Park I, LLC*, 145 FERC ¶ 61,215 (2013), FERC clearly explained that economic curtailment is not allowed in a fixed-price PURPA contract with long-term rates. This order was issued more recently than the MPSC's orders on the topic, but NorthWestern regularly ignores the law and attempts to include economic curtailment clauses in long-term contracts with fixed-price rates. This is illegal. The MPSC should direct NorthWestern to stop insisting upon illegal contract clauses.

3. Market price forecasting methods

This series of questions regards both pricing indexes and the treatment of avoided carbon costs in the calculation of market prices. Crazy Mountain and WINData do not have detailed responses at this time to each subpart, but may respond to comments by others in reply comments or at the workshop.

At a high level, the market prices should be based upon a transparent index, such as the Energy Information Administration's forecasts. Additionally, the cost assumptions should be consistent with what NorthWestern has used to justify its most recent long-term resource acquisition. In the PLLM Hydro acquisition, NorthWestern included significant carbon costs in the analysis, however it shortly thereafter proposed to eliminate reliance on carbon costs for avoided cost rates. The rate assumptions cannot discriminate against QFs. Additionally, as stated above the, the costs of carbon risk are now implicit in electricity market transactions for long-term resources. Therefore, if the QF will provide compliance value for Section 111(d) purposes by providing carbon-free electricity in the State of Montana, its rates should include an avoided carbon compliance adder. Under the Section 111(d) final rule, the QF need not supply the utility with the RECs for RPS compliance in order for the QF's output to be counted towards

Montana's (and NorthWestern's) Section 111(d) compliance, and should thus be provided the avoided carbon cost whether it decides to convey its RECs or not.

4. Resource capacity values

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

No. As discussed above, there is almost certainly a double discount in the payment for capacity to the wind QFs. Additionally, the capacity contribution to peak of only five percent is an unreasonably low assumption. FERC's rules specifically require consideration of "the aggregate" capacity value of QFs selling under standard rates. 18 C.F.R. § 292.304(e)(2)(vi). The analysis should focus on the percentage contribution to peak of *all* QFs selling under standard rates, or at least all wind QFs. When viewed in the aggregate, the output would be more predictable on the system from year to year from these dispersed resources. In contrast to that type of analysis, five percent for any wind project appears to be a rough estimate that is not based on serious analysis.

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 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.

The Commission should use the effective load carrying capability method to recalculate the contribution to peak for wind resources in Montana. This is a well-recognized industry standard that should be used. The impact may vary based on the wind regime in different regions and that could be taken into account.

///

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 Commission should maintain the current regime where the QF is paid for a volumetric rate that includes an assumed capacity contribution. Contracts that penalize the IPP for failure to deliver capacity would typically only apply if the IPP is paid a fixed rate for being available whether it delivers or not. As noted above, under the current regime, the QF has the economic incentive to sell as much of its output as possible and to do so at times when the rate is the highest. If any changes are made, the change should be to include or change the time of delivery pricing adjustments to provide an economic incentive to deliver during times of the day and year when the power is most valuable. However, penalizing the QF for not delivering capacity on top of not paying the QF when it does not deliver (like a utility-owned plant gets paid when it does not deliver) would be inappropriate.

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

Currently, a lack of reliable information about wind integration costs imposes a stumbling point in negotiations for any wind project because NorthWestern claims that its current wind integration study is out of date, but it has not yet updated the study. NorthWestern needs to update its wind integration studies. The Commission should require NorthWestern to update its wind integration costs and should require a reputable third-party to ensure that the study and its methodology and results are reasonable.

Additionally, the Commission should require that the integration costs assessed to the QF a fixed-price reduction over the life of the long-term contract. Because integration costs are a part of the avoided costs, they must be forecasted and fixed for the term of the agreement like any other component of the avoided costs. This is a very important point for financing the construction of the QF project. Without fixed rates, the revenue stream from the project cannot be easily predicted for financing purposes.

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 costs to integrate different resource types on a utility's system will be very specific to each utility. NorthWestern should be required to study, and receive Commission approval of, these costs prior to any such costs being included in avoided cost rates.

5. Requirements for creating a "legally enforceable obligation"

a) Are the Commission's requirements for creating a LEO reasonable? If not, identify and explain any needed changes.

The Commission's rules for creating a LEO are broken and thus lead to disputes. Currently, the Commission's test requires the QF to: (1) tender an executed power purchase agreement to the utility with a price term consistent with the utility's avoided cost, with specific beginning and ending dates, (2) with sufficient guarantees to ensure performance during the term of the obligation, and (3) an executed interconnection agreement. The problem with this test is that the first and second elements – "consistent with the utility's avoided costs" and "sufficient" performance guarantees – are easily disputable for virtually all QFs. Because NorthWestern does not have an approved method to calculate avoided costs for QFs ineligible for standard rates and currently will not even provide any long-term rates to such

QF upon request, it is impossible to know with certainty what rate will satisfy the Commission's requirement that the rate be consistent with NorthWestern's avoided cost. Similarly, there is no indication in any Commission order or rule as to what type or amount of performance guarantee must be offered to ensure the creation of a LEO. Therefore, NorthWestern can attempt to create ambiguity as to whether a LEO was created simply by refusing to provide long-term rates and a reasonable performance guarantee proposal – which is exactly what NorthWestern is currently doing in an effort to avoid Crazy Mountain Wind's LEO from May 2014 and its large QF contract request.

At a minimum, if this test will be retained, the Commission should clarify these points by providing a mechanism by which the QF can itself determine the avoided costs and level of performance guarantees without relying on the utility to provide them. Whatever test is adopted must provide the QF with the ability to obligate itself unilaterally when the utility refuses to negotiate and without any cooperation from the utility. Otherwise, the utility can completely defeat the QF's right to a LEO.

Additionally, the Commission should repeal the requirement that QFs ineligible for standard rates must win a competitive solicitation to obtain a long-term LEO. This rule violates FERC's rules and state law, as found in *Hydrodynamics Inc. et al.*, 146 FERC ¶ 61,193 (2014).

b) Do a QF's rights to bilaterally negotiate and create a LEO weaken, or render ineffective, the competitive bidding rule? Why or why not?

Crazy Mountain and WINData do not support the requirement that the QF must win a competitive solicitation to create a LEO. The practical problem with the solicitation requirement is that NorthWestern does not follow it when it wants to rate-base its own acquisitions and it therefore does not provide meaningful opportunities for QFs. The legal problem with the competitive bidding rule is that it violates FERC's LEO rule and related state law.

For over four years Crazy Mountain has attempted to work through the solicitation process, but there are not adequate or realistic opportunities. Crazy Mountain was able to win a Community Renewable Energy Project ("CREP") solicitation, but was unable to perform on the power purchase agreement after the Commission rejected Crazy Mountain's proposed ownership structure. After multiple and repeated attempts by Crazy Mountain to get a QF contract both as a small and a large OF, Crazy Mountain was forced to enter into a CREP PPA in the face of NorthWestern's long-standing refusal to enter into any other form of long-term contract with QFs over the eligibility size for standard rates. Despite its inability to get approval from the PSC and meet 25MW of NorthWestern's contractual CREP requirements, Crazy Mountain established a LEO in May or 2014 and has been and remains fully willing to sell its 25MW output to NorthWestern as a QF at long-term avoided costs rates. However, NorthWestern is currently relying upon ARM 38.5.1902(5) as a basis to refuse to discuss a long-term contract with Crazy Mountain.

c) Should the Commission consider repealing the competitive solicitation rule? Why or why not?

The Commission should repeal the competitive solicitation rule because it is illegal.

d) If a utility has issued a competitive solicitation for energy or capacity that is open to QFs, would it be reasonable for LEO determinations made after issuance of the solicitation to assume that the solicited resources will be added to the utility's resource portfolio as a result of the solicitation process? Why or why not?

This would be a fact specific determination. Because resources can fail to come online for a variety of different reasons, there is no guarantee that the resource will come online until construction is complete. If there is a high risk that the resource may not come online, then it would be reasonable to assume that the resource is not a committed resource for purposes of calculating avoided costs until it comes online. However, if it is an existing resource and there are no contingencies that could prevent closure of the transaction, then it may be reasonable to assume the resource is a committed resource for purposes of future avoided cost rate calculations prior to the time it is actually delivering electricity to the utility. The utility should have the burden to demonstrate there are no such contingencies at the conclusion of the solicitation in order to update the avoided cost rates calculations.

e) If you answered "yes" to part (d), discuss the implications of that assumption for estimating avoided costs.

Avoided costs would typically be lower after the utility added the new resource to the resources stack, if all other assumptions are held equal.