MEMORANDUM

TO: Commissioners, Kate, Justin, Jason

FROM: Will

DATE: August 11, 2015

RE: PURPA implementation inquiry and roundtable

Background

In April, 2015, the Commission denied NorthWestern Energy's (NWE) application to update standard rates for qualifying facilities (QFs) three megawatts (MW) and smaller. Or. 7338b, Dkt. D2014.1.5 (Apr. 14, 2015). The Commission observed that NWE's acquisition of the PPLM hydroelectric resources "significantly changed [the Company's] existing resource mix and load-resource balance." *Id.* ¶ 28. Because of these changes, the Commission stated that it would "initiate a docket to gather information, conduct roundtable discussions and review its implementation of PURPA." *Id.*

The Commission stated that it intends to explore PURPA-related issues including, but not limited to: (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." *Id*.

In this memo, staff provides advice regarding possible content for a Commission *Notice* initiating a PURPA implementation review docket. Staff recommends that the Commission first solicit written comments from stakeholders regarding the docket's issues. Staff recommends that the Commission then use the written comments it receives to guide subsequent roundtable discussions toward a constructive dialogue.

Possible content for a *Notice Initiating Docket*

Staff recommends that the Commission initiate the PURPA review docket with a *Notice* that solicits input from stakeholders on the specific items listed in *Order 7338b* as well as on any other issues the stakeholders feel are important. A possible framework for soliciting stakeholder input follows.

1. Methods for estimating avoided costs

The Edison Electric Institute (EEI) has identified three types of methods used by states to implement PURPA: (1) The "proxy" method; (2) the "component/peaker" method; and (3) the "differential revenue requirements" method.[1] According to EEI, the proxy method assumes that QF power purchases allow a utility to delay or displace its next planned generating unit. Under the proxy method, as described by EEI, the proxy unit's estimated fixed costs are deemed to be avoided capacity costs and estimated variable costs are deemed to be avoided energy costs.

Under the component/peaker approach, avoided capacity costs are based on a utility's least-cost capacity option and avoided energy costs reflect marginal energy costs estimated with a production cost simulation model. EEI states that the component/peaker method does not calculate avoided cost based on the expected cost of a planned resource, but assumes that QF power allows the utility to reduce the marginal generation on its system and avoid building a combustion turbine equal in size to the QFs' capacity contribution.

The differential revenue requirement method calculates a utility's total generation cost (revenue requirement) with and without an assumed amount of "free" QF capacity with specified operating characteristics. The present value difference in total generation costs between the two cases is the lump sum avoided cost for the modeled QF power.

EEI notes that states have used variants of the above three methods as well as other methods to implement PURPA. This Commission has applied modified versions of the proxy method to set QF rates for small QFs. For example, the blended market-CCCT method the Commission adopted in Docket D2012.1.3 used market purchase costs in the near term and the cost of owning and operating a combined cycle gas plant in the longer term as proxy resources. Rather than basing avoided capacity costs on the full fixed costs of the combined cycle plant, the Commission based avoided capacity costs on the fixed costs of a simple cycle gas plant. The difference between the fixed costs of a simple cycle gas plant and a combined cycle gas plant were classified as avoided energy costs to recognize that the higher capital costs of the combined cycle plant are justified by its lower energy cost, which allows the combined cycle plant to operate more like a base load plant than a peaking plant.

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[1] Edison Electric Institute, *PURPA: Making the Sequel Better than the Original*, p. 9 (Dec. 2006). Staff did not perform an exhaustive literature search for avoided cost methods.

EEI states that selecting an avoided cost method involves a trade-off between theoretical accuracy and practicality. For example, while the Commission's versions of the proxy method have been relatively straightforward and transparent, aspects of the component/peaker and differential revenue requirements methods involve complex, "black box" computer models (e.g., PowerSimm), although, according to EEI, these methods are more sophisticated and conceptually correct ways of determining avoided cost.

Questions for stakeholders:

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?

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?

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?

2. Standard rate design

NWE's QF tariff schedules include a number of provisions, in addition to rates, that affect a power purchase agreement between NWE and small QFs. In the past, such provisions have addressed available contract lengths, generating technology-specific rates and adjustments, and levelization options. For example, in 2006, the Commission approved a maximum contract length of 15 years under the QF-1 tariff schedule. In 2010, the Commission approved a rate option specifically for wind QFs with a contract length of 25 years. NWE's current tariff establishes rates for wind and non-wind QFs for contract lengths of up to 25 years.

Questions for stakeholders:

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?

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?

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

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"?

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?

3. Market price forecasting methods

In the past, the Commission has estimated NWE's avoided costs using near-term forward market prices for natural gas prices and electricity with longer term natural gas price escalation based on Energy Information Administration (EIA) reference case natural gas price forecasts. In addition, given uncertainty regarding the timing and impact of carbon dioxide (CO_2) emissions regulation, the Commission has accounted for incremental CO_2 emissions costs in several ways. Currently, a QF that contractually conveys renewable attributes to NWE will receive an adjustment to its contract rates based on actual costs NWE incurs to comply with state or federal CO_2 emissions regulations. Alternatively, a QF can sell its renewable attributes separately to NWE or any other interested buyer at a negotiated price. In the past, the Commission has estimated avoided costs based on resource costs that reflected assumed incremental CO_2 emissions costs. *See* Or. 6973d, Dkt. D2008.12.146, ¶¶ 145-47 (Apr. 13, 2010) (setting an "Option 3" rate for wind QFs based on preferred resources NWE selected in its 2007 resource plan which contained CO_2 emissions cost assumptions). The Commission has also recognized that forecasting is prone to error, and in that regard, has sought information from NWE on how alternative forecasts affect resource planning outcomes. *Written Comments*, Dkt. N2011.12.96, ¶ 17 (Sept. 28, 2012).

Questions for stakeholders:

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 "snap-shot" taken at a particular point in time? Why or why not?

d) Is the Commission's current approach to accounting for estimates of the incremental costs of CO_2 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 CO_2 emissions?

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?

4. Resource capacity values

NWE's current QF-1 tariff schedule recognizes that wind power facilities provide less capacity value relative to the proxy generating resource used to estimate the avoided costs. The QF-1 tariff schedule pays wind power facilities for capacity based on five percent of the facility's nameplate capacity. Or. 7199d, Dkt. D2012.1.3, ¶ 52 (Nov. 20, 2012). Reasonably accurate estimates of the capacity value of resource alternatives is important for both long-term resource planning and QF rate setting, and the Commission has advised NWE to consider alternative capacity valuation methods, including effective load carrying capability and exceedance measures. *Id*. at ¶ 53; *Comments*, Dkt. N2013.12.84, ¶ 19 (May 26, 2015). Another capacity-related issue pertains to the incremental cost of integrating additional quantities of energy and capacity from intermittent generating resources, particularly wind power.

Questions for stakeholders:

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

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.

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).

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.

5. Requirements for creating a "legally enforceable obligation"

EEI notes that, starting in the late 1980s, some states incorporated bidding mechanisms into their PURPA procedures as a way of identifying the most economical QFs to fill utilities' energy and capacity needs. The Commission has adopted a competitive bidding rule governing long-term contracts between utilities and large QFs. Admin. R. Mont. 38.5.1902(5). However, the competitive bidding process is not the only way for a large QF to obtain a contract to sell its energy and capacity to a utility. Utilities and QFs always have the right to negotiate the terms of energy and capacity purchases and sales. Admin. R. Mont. 38.5.1905(2). In addition, the Commission has established a method for QFs to create non-contractual, but still legally enforceable obligations (LEO) for utilities to purchase their energy and capacity. *See* Or. 6444e, Dkt. D2002.8.100, ¶ 47 (May 18, 2010). To establish a LEO a QF must 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, and with sufficient guarantees to ensure performance during the term of the obligation, and an executed interconnection agreement.

Questions for stakeholders:

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

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?

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

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?

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