<u>Renewable Northwest Project Proposal: Proxy Plant Methodology to Determine the Cost of Non-Qualifying Electricity for RPS Cost Off-Ramp</u>

RNP proposes a methodology that estimates the "all-in" costs of a proxy combined cycle natural gas plant to determine "the levelized annual delivered cost of an equivalent amount of reasonably available electricity that is not qualifying electricity" for purposes of the RPS cost off-ramp called for in SB 838, Section 12(4). The proposed proxy plant method levelizes the expected "net present value" of the "delivered cost" of "an equivalent amount" of non-qualifying electricity that is "reasonably available" at the same time that the qualifying resource is acquired (the proxy plant could represent either a utility-owned generating asset or a PPA).

A forward price curve estimate of expected future electricity prices does not constitute an estimate of non-qualifying electricity that is "reasonably available" at the time a qualifying resources is brought online or into rates. Such price curves are generally estimates of spot market transaction costs at a given future date, and are not equivalent to the cost to purchase an amount of electricity *today* for delivery at that future date. It is common, and acceptable practice to rely on commodity futures prices where liquid markets for futures exist. Unfortunately, a liquid futures market for electricity does not exist, and most price curve forecasts do not reflect futures prices, although the approximation may be close for the most immediate month and extending out perhaps four quarters.

It may be possible for a utility to enter into a contract today for delivery of a "strip" of non-qualifying electricity over the course of the contract-length or plant life of the qualifying electricity, but entering into such a contract would incur additional transaction costs not represented in typical forward price curves. Any counterparty willing to enter into a long-term contract for the future delivery of power purchased in the spot market, the counterparty would require a significant hedging premium to cover expected price volatility in the spot market and regulatory risk. This is because the counterparty bears the risk that future spot market prices will actually be higher than the estimates in the forward price curve and will charge a hedging premium accordingly. Additionally, the utility would likely require credit guarantees from the counterparty for any long-term contract, which would incur an additional credit premium. Even if the counterparty does not have to post a bond or letter of credit, Financial Accounting Standards Board accounting standards may require the counterparty to carry imputed debt on their books until the contract is fulfilled, which represents a transaction cost.

In reality, any long-term contract "reasonably available" to the utility would likely be a Power Purchase Agreement (PPA) and the counterparty would base the price of the PPA on capital and expected operating costs of an actual plant, plus an appropriate profit margin. Alternatively, the utility could build or acquire their own generating facility to provide an equivalent amount of non-qualifying electricity, in which case the price would again be based on the costs of an actual plant. We therefore propose a "proxy plant" methodology as the best way to estimate the costs in a manner consistent with the intent of the law.

Proposed "Proxy Plant" Methodology:

1) Estimate the capital cost (including any interconnection costs[1]), fixed O&M, variable O&M (excluding fuel costs) and any appropriate taxes for the proxy combined cycle natural gas plant, as well as any financing costs associated with these capital, operating and maintenance costs (as per Section 12(4)(a) and (b)).[2] Cost estimates should be drawn from actual combined cycle gas plants recently constructed in the region, if available, and/or from utility IRP assumptions, and/or vendor estimates. Cost estimates should be broadly representative of plants actually being developed in the region.[3]

2) Develop a levelized annual cost per kWh from the net present value of the costs estimated in 1) above.[4]

3) Estimate fuel prices per mmBtu for the full capital recovery period of the plant. For in years (up to years 1-6), fuel costs can be based on actual NYMEX Henry Hub futures market prices.[5] For out years (all other years), fuel costs can be from an appropriate forward price curve (e.g. EIA, NWPCC, or private sector forecasts[6]). Prices in all years need to be adjusted to reflect delivery to Northwest hubs, rather than Henry Hub, and need to be adjusted to include "hedging costs" that represent the additional expense incurred to guarantee the purchase price of natural gas (i.e. to actually transact at the prices observed on NYMEX).[7]

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[1] This would include any appropriate "substation costs" as per Section 12(4)(c).

[2] QUESTION – Capital Structure: what should be assumed about the capital cost structure used to finance the proxy plant – i.e. what ratio of debt to equity? Should the proxy plant represent a utility-owned asset, or a PPA with an independent power producer? CalPUC ultimately decided on an IPP plant with a debt/equity ratio of 70/30 (see CalPUC http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/37383-02.htm)

[3] Note that this step should be consistent with the methodology used to establish the cost of the proxy CCCT plant used to determine Oregon avoided cost schedules for PURPA QFs.

[4] QUESTION – Capital Recovery Term: should the costs be levelized over the same capital recovery period assumed by the Qualifying Resource, or over a different but appropriate capital recovery period for the proxy plant? In CA, CEERT argued for same time period but CalPUC ultimately decided on a 20 year capital recovery period for the natural gas proxy plant, regardless of the recovery period for the renewable resources.

[5] NYMEX Henry Hub futures sell for contracts out to 72 months, or six years. See http://www.nymex.com/ng_fut_descri.aspx However, transaction volumes for years 5 and 6 are sometimes low, and may not be appropriate to use for cost estimates. CalPUC chooses each year which of years 1-6 it wants to use from NYMEX based on observed trading volumes. In 2005-2007, the CalPUC opted to use NYMEX futures market values for years 1-5 only. See http://docs.cpuc.ca.gov/PUBLISHED/RULINGS/43825.htm

[6] CalPUC uses the average of EIA Henry Hub forecasts and two of the three following private sector Henry Hub forecasts: Cambridge Energy Research Associates (CERA), PIRA Energy Group, or Global Insight. See http://docs.cpuc.ca.gov/PUBLISHED/Final_resolution/73594.htm

[7] Note this methodology should be broadly consistent with the methodology used to establish fuel costs for the proxy CCCT plant used to determine Oregon avoided cost schedules for PURPA QFs. However, since avoided cost rates are determined using forward price curves for electricity markets in the "resource sufficiency" period, using the NYMEX futures market prices is not appropriate in the avoided cost

4) Multiply the fuel cost price derived in Step 3) by the assumed heat rate of the proxy plant to derive the fuel cost per kWh in each year that would be incurred as a variable operating cost (as per Section 12(4)(a)). Then develop a levelized annual cost per kWh from the net present value of the fuel costs and add it to the levelized annual costs derived in 2).

5) Estimate environmental costs for the plant, including actual or expected costs for carbon dioxide (and other greenhouse gases), mercury, SOx and NOx emissions. Using the assumed heat rate of the proxy plant, estimate total fuel consumed in each year and derive estimated annual emissions of each pollutant. Then use environmental cost assumptions from the utility's IRP base case to determine annual environmental costs that would be incurred as a variable operating cost (as per Section 12(4)(a)). Levelize the net present value of these environmental costs and add to the subtotal derived in 4).[8]

6) Estimate transmission costs (as per Section 12(4)(c)) based on the utility's point-to-point delivery tariff, BPA's point-to-point tariff or an appropriate network transmission rate.

7) Develop a levelized annual cost per kWh from the net present value of the transmission costs derived in 5) and add this value to the subtotal derived in 5). This should yield the final, levelized annual delivered cost per kWh of non-qualifying electricity from the proxy plant. To yield the total cost of an equivalent amount of non-qualifying electricity, multiply this levelized annual delivered cost per kWh by the quantity of annual delivered qualifying electricity.

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methodology. In this case, however, actual NYMEX futures market prices offer a more accurate price estimate than forward price curves for early years (up to year 6) and should be used in this methodology. Additionally, we propose inclusion of hedging costs as per the CalPUC proxy plany methodology used to determine their market price referent (MPR). We note that there was unanimous agreement among all parties in CalPUC proceedings establishing the MPR for the California RPS that hedging costs must be added to the observed costs of natural gas futures market transactions. The CalPUC adopted a methodology that takes ½ of the observed Bid/Ask spread on NYMEX and adds to it collateral costs representing a letter of credit at 1.25% to come up with a hedge cost estimate. See http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/37383-02.htm

[8] This step should be consistent with the methodology used in IRPs to determine the expected environmental costs of a proxy power plant.