BEFORE THE PUBLIC UTILITIES COMMISSION OF

THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Implementation and Administration of California Renewables Portfolio Standard Program	Rulemaking 11-05-005 (Filed May 5, 2011)

REPLY COMMENTS OF THE UTILITY REFORM NETWORK ON THE REVISED STAFF PROPOSAL AND ALTERNATIVE PROPOSALS FOR A METHODOLOGY TO IMPLEMENT PROCUREMENT EXPENDITURE LIMITATIONS FOR THE RENEWABLES PORTFOLIO STANDARD PROGRAM

TURN
THE UTILITY REFORM NETWORK
Lower bills. Livable planet.

Matthew Freedman
The Utility Reform Network
785 Market Street, 14th floor
San Francisco, CA 94103
415-929-8876 x304
matthew@turn.org
April 3, 2014

REPLY COMMENTS OF THE UTILITY REFORM NETWORK ON THE REVISED STAFF PROPOSAL AND ALTERNATIVE PROPOSALS FOR A METHODOLOGY TO IMPLEMENT PROCUREMENT EXPENDITURE LIMITATIONS FOR THE RENEWABLES PORTFOLIO STANDARD PROGRAM

Pursuant to the February 20, 2014 ruling of ALJ Simon, The Utility Reform Network (TURN) hereby submits these reply comments on the revised staff proposal and updated alternative proposals for a methodology to implement the Procurement Expenditure Limitation (PEL) contained in Public Utilities Code §399.15 and enacted in SBx2 (Simitian). TURN replies to the opening comments of the Alliance for Retail Energy Markets (AREM), the Green Power Institute (GPI), and Pacific Gas & Electric (PG&E).

I. TURN AGREES THAT THE CALWEA PROPOSAL REPRESENTS AN APPROPRIATE METHOD FOR MEASURING RETAIL RATE IMPACTS OF RPS PROCUREMENT

In opening comments, GPI states that the CALWEA proposal offers the advantage of estimating the difference between RPS and non-RPS scenarios (including carbon costs) in order to determine actual net impacts on ratepayers.[1] Unlike the Staff Proposal and SCE/Joint Parties approach, CalWEA offers a rate impact analysis that estimates costs under a "no mandate" case relying upon calculations of incremental procurement costs that incorporate current market realities, GHG costs, and potentially some non-fossil resources to be acquired via all-source solicitations.

TURN is concerned that attempts to benchmark RPS costs against escalated historical generation costs (as proposed by the Staff and SCE/Joint Parties) ignore the fact that incremental procurement expenditures (under a no-RPS scenario) are unlikely to reflect the embedded portfolio costs. Existing generation costs include heavily

[1] GPI opening comments, pages 6-7.

depreciated utility-owned nuclear and hydroelectric plants along with non-renewable Qualifying Facilities, regional power exchange agreements that date back decades, and other conventional resources procured over the past decade. This mix is not reflective of prospective procurement costs under any scenario. In the absence of additional RPS procurement, the utilities might otherwise seek to procure high-cost newly developed generating units that cost far more than legacy procurement obligations. Escalating historical costs by a fixed adder does not appear to represent a realistic scenario for approximating true incremental costs in the absence of ongoing RPS purchases.

Moreover, the use of a fixed escalator to the existing portfolio does not properly reflect forecasted GHG allowance costs over a 10-year period. For example, PG&E's nuclear and hydroelectric resources do not incur any GHG allowance costs. Applying a fixed escalator to the cost of these resources would not properly value the expected costs of procurement under a no-RPS scenario for new fossil generation that does require GHG allowances.

TURN recognizes the challenges of attempting to construct the projected costs and resource mix associated with a no-RPS scenario. The Commission should only adopt this approach if it can be synced with the assumptions included in the LTPP process for each utility. It would be a mistake to require separate modeling efforts in the LTPP and RPS proceedings that involve divergent assumptions. If the Commission can find a way to link the LTPP assumptions to the PEL methodology, TURN believes that the CalWEA approach could best measure the true rate impact of RPS procurement.

II. THERE IS NO BASIS FOR PROVIDING ANY RELIEF TO NON-UTILITY RETAIL SELLERS IN THE EVENT THAT THE PEL FOR A PARTICULAR UTILITY IS EXHAUSTED

AREM asserts that the Commission should allow Electric Service Providers (ESPs) to receive automatic waivers, procurement quantity reductions or other forms of compliance relief in the event that an IOU exceeds its PEL. Claiming that providing "additional procurement flexibility" would ensure "a level playing field", AREM proposes that any determinations allowing IOUs to be relieved of RPS procurement should carry over to ESPs and other non-IOU retail sellers.[2]

The Commission should deny AREM's proposal. There is no basis in the statutory text to support this outcome. The PEL sections of the Public Utilities Code apply solely to "electrical corporations" and make no reference to special treatment for other retail sellers in the event that an IOU exceeds its cost limitation. AREM fails to point to any code section that supports its interpretation and offers no logical argument as to why any particular relief should be provided to one or more ESPs in the event that an individual IOU exceeds its PEL.

It is irrational to argue that ESPs should be eligible for compliance waivers if a single IOU exceeds its PEL. Under AREM's theory, it would make just as much sense for the Commission to allow <u>all IOUs</u> to receive compliance waivers in the event that a <u>single IOU</u> exceeds its PEL. ESPs have customers across the state and throughout multiple service territories. AREM has not explained why broad statewide relief should be considered in the event that a single IOU exceeds its PEL.

Finally, the fact that an IOU has exceeded its PEL offers no insight into the reasonableness of costs incurred by an ESP. The IOU may exceed its PEL due to

[2] AREM opening comments, pages 2-3.

many factors, only one of which is generally high market prices. ESPs have their own portfolios, unique procurement strategies, and unregulated retail rates. There is no basis for the Commission to conclude that the circumstances tied to an individual utility exceeding the PEL are relevant to the unique business practices of ESPs.

The cost containment limits apply only to IOUs because their procurement contracts are subject to Commission review and approval. Moreover, utility generation rates are approved by the Commission and must be "just and reasonable" pursuant to §451 of the Public Utilities Code. By contrast, ESPs and other non-IOU retail sellers do not have individual procurement contracts subject to Commission approval and do not have their retail rates regulated by the Commission. As a result, the Commission has no mechanism for ensuring that ESP procurement is prudent and protects direct access customers from disproportionate rate impacts.

For these reasons, the Commission should reject any attempt to link the PELs to procurement quantity reductions, waivers or other forms of relief for retail sellers other than electrical corporations.

III. THE RENEWABLE NET SHORT SHOULD BE TIED TO THE PHYSICAL NET SHORT POSITION

In opening comments, PG&E argues that the calculation of the PEL should not be based on the assumption that banked surpluses are applied to the net short over a 10-year rolling period. Instead, PG&E proposes that the physical Renewable Net Short (RNS) should be used to determine procurement quantities that will be subject to the PEL.[3] TURN agrees with PG&E. It would be unreasonable to assume, in calculating the PEL, that all banked procurement will be applied to the 10-year RNS.

[3] PG&E opening comments, pages 3, 15-17.

This approach would leave a utility with zero banked procurement at the end of the 10-year period and underestimate the true need for advance procurement. Experience with the RPS since its inception should demonstrate that 'just-in-time' procurement strategies are likely to fail. Not only are delays and project failures common, but any procurement strategy that places a premium on deliveries in a particular year could drive up market prices. The PEL should not restrict the opportunity for utilities to hold their banked surplus and engage in advanced procurement to prevent the need to scramble to fill looming near-term shortfalls.

Furthermore, utilities should have flexibility (subject to ongoing Commission oversight) with respect to their use of any banked surplus. For example, there may be value to deploying banked surplus in a year when prices are high so the utility can sell existing contractual deliveries to third parties and maximize sales revenues. The PEL should not discourage or otherwise hamper the ability of utilities to use the banked surplus in a manner that realizes maximum value for bundled ratepayers.

IV. PG&E'S PROPOSED USE OF A 2% "BUFFER" DOES NOT REFLECT THE EXTENT TO WHICH UTILITIES HAVE DIFFERENT OPEN POSITIONS AND DOES NOT EFFECTIVELY APPROXIMATE THE NET IMPACT OF RPS PROCUREMENT ON RATES

PG&E's opening comments propose a "disproportionality threshold of 2% of an IOU's Total Generation Revenue Requirement" that should be added to the forecasted cost of filling any identified physical net short.[4] PG&E justifies this approach based on the PEL adopted by the Merced Irrigation District (MID). This comparison is inappropriate and irrelevant.

Although PG&E may believe that IOUs and Publicly Owned Utilities should adopt

---

[4] PG&E opening comments, pages 4, 8, 25, 28.

comparable RPS rules, this principle should not justify a race to the bottom. MID represents one of the worst performing Publicly Owned Utilities with respect to RPS compliance and has been primarily focused on waivers rather than results. According to its power content label, MID procured approximately 2.7% of retail sales from RPS-eligible resources in 2010 and 2011 and dropped to 2.6% RPS-eligible resources in 2012. Practically all of its remaining portfolio needs have been satisfied via purchases of non-renewable system power.[5] MID's primary RPS compliance strategy to date involves sponsoring legislation to allow a partial exemption from RPS requirements.[6]

Moreover, PG&E fails to explain why 2% of generation revenues represents an appropriate buffer above forecasted incremental RPS costs. As shown in its own illustration, the 2% buffer does not scale in proportion to the amount of the physical RPS net short. While RPS net short expenditures are expected to more than triple between 2019 and 2023, PG&E's proposed buffer would increase by only 17% over the same period.[7] To the extent that there is a buffer included in the PEL, it should scale in some proportion to changes in the expected net short. Instead, PG&E's proposal would establish similar buffer amounts regardless of whether the RPS net short in a given year is 1 MWh or 1,000 GWh. This approach does not reflect any of the statutory guidance or a common sense understanding of how to determine rate impacts and assess whether they are disproportionate.

[5] http://www.mercedid.org/index.cfm/power/energy-rulesfeesrates/power-content-label/
[6] See SB 591 (Cannella, 2013) and new Pub. Util. Code §399.30(k).
[7] PG&E opening comments, Appendix A (PG&E's proposed 2% buffer modification).

V. USE OF NET MARKET VALUE TO MEASURE DE MINIMIS RATE IMPACTS

TURN supports the staff proposal that any incremental procurement with positive Net Market Value (NMV) does not cause more than a "de mimimis" impact on rates. In opening comments, PG&E argues that the Commission should allow PG&E to instead use its Portfolio-Adjusted Value (PAV) methodology to assess whether renewable products offer positive portfolio value.[8] In past comments, TURN has expressed concern about PG&E's PAV methodology and continues to believe that it contains a number of elements that arbitrarily assess negative market value to renewable products.[9] Until the Commission has the ability to undertake a much more careful review of the PAV methodology, it should not be permitted as an NMV proxy or substitute. The Commission should instead rely on NMV for purposes of measuring whether there is an impact on rates that would exceed the "de minimis" test.

Respectfully submitted,

MATTHEW FREEDMAN

___________/S/___________
Attorney for
The Utility Reform Network
785 Market Street, 14th floor
San Francisco, CA 94103
Phone: 415-929-8876 x304
matthew@turn.org

Dated: April 3, 2014

---

[8] PG&E opening comments, page 6.

[9] For example, TURN identified PAV adjustments that arbitrarily favored 10-15 year contract terms over longer term offers. In D.13-11-024 (pages 44-45), the Commission agreed with TURN and directed PG&E to remove this element from the PAV. The Commission also approved PG&E's PAV methodology only for the 2013 solicitation and stated that further review would be needed before authorizing this approach for other purposes.

VERIFICATION

I, Matthew Freedman, am an attorney of record for THE UTILITY REFORM NETWORK in this proceeding and am authorized to make this verification on the organization's behalf. The statements in the foregoing document are true of my own knowledge, except for those matters which are stated on information and belief, and as to those matters, I believe them to be true.

I am making this verification on TURN's behalf because, as the lead attorney in the proceeding, I have unique personal knowledge of certain facts stated in the foregoing document.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on April 3, 2014, at San Francisco, California.

___________/S/___________

Matthew Freedman
Staff Attorney