Energy Choice Matters
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PUCT Staff Draft Proposal for Publication Maintains Solar Carve-Out, Raises ACP

PUCT Staff filed a proposal for publication creating both a solar and non-wind, non-solar RPS carve-out, increasing from a strawman both the amount of the solar carve-out and the alternative compliance payment for the solar carve-out (35792).

In a story that appeared in *Matters* before anywhere else, the strawman called for setting the RPS at 5,000 MW of new resources in 2014 and each year thereafter, including 500 MW from non-wind renewable resources, 50 MW of which were to be from solar resources (Matters, 12/22/09).

The Staff draft proposal for publication, taking an additional year to implement the new carve-outs, calls for the RPS to be set at 6,380 MW of renewable resources for each year after 2014, including 400 MW from non-wind renewable energy resources (other than solar resources), and 100 MW from solar resources.

The following transition period would be used to achieve this end state:

- 4,264 MW of renewable resources in 2010 (with no carve-out)
- 4,389 MW of renewable resources in 2011, including 100 MW from new non-wind renewable resources (other than solar resources), and 25 MW from solar resources
- 5,506 MW of renewable resources in 2012, including 200 MW from new non-wind renewable resources (other than solar resources), and 50 MW from solar resources;
- 5,631 MW of renewable resources in 2013, including 300 MW from new non-wind renewable

Continued P. 6

California Direct Access Caps Assuredly Hit, Though No Utility Confirmation

Though no utility was able to provide definitive numbers Friday evening, each California utility all but assuredly hit its direct access cap for Year One of the phase-in of new direct access load.

Although the utilities could not provide definitive data, competitive suppliers, though none wished to be named, reported submitting Notices of Intent with associated load that will exceed the caps, provided that the NOIs were properly executed and are accepted by the utilities. With suppliers essentially holding their fingers over their mouses geared for the strike of 9:00 a.m. Pacific time on Friday for emailing the NOIs, the caps were effectively hit instantaneously.

San Diego Gas & Electric, while not able to provide load data, was able to quantify the amount of submissions of Notices of Intent in the first few minutes of the enrollment window as numbering in the thousands. Based on these results, SDG&E was confident that it has already hit its cap.

Southern California Edison said that it would be Monday afternoon before any preliminary information would be available, while Pacific Gas & Electric indicated the process could take longer.

Year One caps per utility (not including the 10% threshold above the Year One limit which may be accepted) were 35% of 3,946 annualized GWh at SCE and PG&E, and 35% of 462 annualized GWh at SDG&E.

As things currently stand, customers wait-listed for acceptance into the Year One direct access enrollment will potentially have an opportunity in 60 days to submit a direct access service request

Continued P. 7

Pa. PUC Updates Comparison of Capped Rates, Market Prices

The Pennsylvania PUC has released its latest comparison of current capped generation rates and recent wholesale electric prices. For Met-Ed, Penelec, and West Penn Power (Allegheny), where at least 50% of default service supplies have already been procured for 2011, the PUC also provided comparisons between current rates and the average winning procurement price.

Projected Increase in Generation Rates

Met-Ed	Vs. Wholesale Prices 3/31/10	Vs. Avg. SOS Auction Results
Residential	26.4%	10.3%
Commercial	23.5%	11.4%
Industrial	21.1%	N/A

Penelec	Vs. Wholesale Prices 3/31/10	Vs. Avg. SOS Auction Results
Residential	16.0%	19.8%
Commercial	14.3%	18.3%
Industrial	19.0%	N/A

West Penn Power	Vs. Wholesale Prices 3/31/10	Vs. Avg. SOS Auction Results
Residential	4.7%	8.5%
Small Commercial	2.3%^	0.6%
Medium Commercial		2%
Industrial	(2.6%)	N/A

PECO	Vs. Wholesale Prices 3/31/10
Residential	(8.2%)
Commercial	(14.3%)
Industrial	(12.3%)

^2.3% figure is for combined commercial classes

Champion Energy Services Breaks 9-Cent Residential Barrier at PPL

Champion Energy Services has begun offering residential electric service to customers at PPL Electric, with an aggressive offer of 8.88¢/kWh fixed through the December 2010 meter read, which is lower than all non-introductory variable and fixed rates in the market by over 4 mils. The next lowest fixed-though-December 2010 offer is 9.39¢/kWh from Verde Energy, while Washington Gas Energy Services offers a rate of 9.30¢/kWh fixed through January 2011.

Champion's product includes a termination fee of $10 per month remaining on the contract.

Champion Energy Services is also offering the lowest priced 100% wind plan at 10.8¢/kWh fixed for a 12-month term, versus Direct Energy's offer of 10.99¢/kWh for the first three months and 11.49¢/kWh thereafter.

Champion is offering a 12-month fixed product at 9.30¢/kWh, against Direct Energy's offer of 8.99¢/kWh for the first three months and 9.49¢/kWh thereafter, and ConEdison Solutions' flat offer of 9.39¢/kWh for 12 months. WGES is offering a fixed rate of 9.30¢/kWh, but only for a term of at least 24 months (or through January 2011, but not for 12 full months).

Both of Champion's 12-month fixed plans include the $10/month termination fee. Champion's entry brings the number of suppliers currently making residential offers at PPL to 10, with 12 load-serving residential suppliers (with Anthracite and Liberty not currently making a broadly available offer).

Competitive Suppliers Oppose Discriminatory Provision of Unsecured Credit at ISO-NE

Competitive load serving entities opposed ISO New England's "discriminatory" proposal to eliminate unsecured credit for all market participants except transmission and distribution providers serving native load customers at government-established rates, informing FERC that such an unsupported dichotomy in credit rules, "will skew the market significantly," and may ultimately lead to exits from the market, harming competitive outcomes (ER10-942).

As only reported by *Matters*, ISO-NE would eliminate unsecured credit for all market participants except Municipal Market Participants, T&D Companies, and Non- Market Participant Transmission Customers who serve customers at government-established rates. The ISO also requested to further shorten the cycle for billing and payment for Hourly Charges from once each week to twice each week (Only in Matters, 3/30/10).

Filing as the New England Credit Policy Coalition, competitive suppliers argued that ISO-NE provided no justification for treating similarly situated entities -- companies with investment-grade credit ratings -- differently, by extending unsecured credit to POLR-type providers, but denying such credit to other investment-grade firms.

"Even if one assumes that municipals and T&D companies are good credit risks because they are authorized to recover their costs through governmentally-approved rates, it does not automatically follow that other entities that transact at market-based rates are poor credit risks," the Credit Policy Coalition said, whose ad hoc members include Constellation NewEnergy, ConEdison Solutions, Energy America, Exelon Generation, Hess Corporation, PSEG Energy Resources & Trade, and Shell Energy North America.

The Coalition stressed that even though POLR providers may have rates set by government agencies, "[c]ost recovery through regulated rates involves substantial regulatory lag and requested cost recovery may be denied on prudence or other grounds."

"The delays and uncertainties associated with rate cases makes them an imperfect remedy where cost increases are sudden and unexpected and where cost recovery is needed quickly," the competitive suppliers said, in arguing that government-set rate authority is not sufficient to justify disparate credit treatment.

The Coalition cited the recent controversy at LADWP regarding its requested rate increase which was not fully allowed, and the resulting fallout which included ratings downgrades. Competitive suppliers further cited the bankruptcies of Public Service Company of New Hampshire and Pacific Gas & Electric, the latter of which's bankruptcy was precipitated by the denial of recovery for increased commodity costs, as evidence that load-serving entities are with government-set rates, "are not immune from insolvency."

"The discriminatory approach reflected in the Proposed Amendments will reduce the amount of unsecured credit, but does so in a way that has significant adverse consequences. This proposal, if adopted, will skew the market significantly by imposing additional costs on competitive suppliers, including the Coalition Members, while exempting regulated load serving entities, such as municipal utilities and state-regulated transmission and distribution companies, from these costs, an outcome that will undermine competition to the detriment of consumers," the Coalition contended.

Furthermore, the Coalition said that ISO-NE's proposal would still result in customers paying collateral costs, while still being exposed to the default of those POLR entities granted unsecured credit. "This outcome is most evident in the circumstances where a state-regulated load serving entity purchases energy from a competitive supplier, transactions that are associated with approximately one-half of the load in New England. In this circumstance, the costs of full collateralization will be reflected in the price paid for energy by the state-regulated load serving entity. Moreover, because the state-regulated entity remains at risk for the potential payment default costs associated with other municipals and T&D companies that have unsecured credit, those risks are also ultimately passed through to its customers. Thus, while the Proposed Amendments exempt the municipal or T&D company from the higher collateral costs borne by competitive load serving entities, its customers pay such costs through higher energy costs and continue to bear the risk of potential defaults. This outcome provides no identifiable customer benefit and illustrates the Proposed Amendments' fundamental flaw," the Coalition said.

The Coalition further cited its concern that ISO-NE elected to submit the credit revisions after the issuance of FERC's credit reform NOPR in order to achieve an end-run around the NOPR, especially as the ISO-NE's changes had previously been approved for filing but had not been filed. The ISO's recent filing, "may reflect an attempt to 'get in under the wire' before the new regulations that result from the Credit NOPR, regulations that may not authorize aspects of the Proposed Amendments, become effective. This concern is highlighted further by ISO-NE's and NEPOOL's request that the Commission act now on the Proposed Amendments while the tariff changes would not become effective until December 1 2010, at the earliest," the Coalition noted.

ISO-NE had justified the elimination of unsecured credit for most market participants by warning FERC of potential "sleeving" in the market under which otherwise-bilateral transactions (such as contracts for difference) are not submitted to the ISO but are conducted through the ISO spot market, in order to socialize any potential non-performance by either party. However, the competitive suppliers pointed to "many profound flaws" in ISO-NE's argument, including the fact that the mere act of a buyer purchasing energy from ISO-NE cannot increase ISO-NE's credit default exposure because the buyer, whether or not it has entered into a contact for difference with a seller, still has to meet ISO-NE's creditworthiness standards.

Additionally, while the ISO said that a decrease in internal bilateral transactions is evidence of such sleeving, the Coalition noted that the implementation of weekly settlements creates incentives for suppliers to favor settlements in the ISO-NE market over bilateral transactions, which generally involve payments on a bi-weekly or monthly basis. Market standard agreements that are the vehicle for most bilateral transactions, such as the EEI Master Power Purchase & Sale Agreement and the ISDA Master Agreement with Power Annex, provide for monthly billing cycles. "Suppliers will therefore opt out of bilateral transactions in order to be paid sooner," the Coalition explained.

The Coalition also presented an expert affidavit arguing that the proposed changes would not be cost effective, as imposing increased collateralization costs on a large share of the active market participants will increase costs far in excess of any potential savings. Relying on ISO-NE data, the Coalition estimated that the proposed changes would require approximately $256 million of additional collateral, with an annual cost of $7.7 million.

In separately filed comments, ConEdison Solutions opposed the proposed twice-weekly settlements noting that the current weekly settlements already require an LSE to utilize a significant amount of working capital to bridge the interval between payments to ISO-NE and collection from customers. "Further shortening the settlement time to twice-weekly only exacerbates this problem, and increases customer costs," ConEdison Solutions said.

Furthermore, twice weekly settlements would double administrative costs, ConEdison Solutions added. "Much of the settlement data must be estimated due to the lack of verifiable, revenue grade metering at the initial settlement. The additional burden of reconciling the estimated data increases the cost of settlement further," ConEdison Solutions said.

BP Energy agreed that, "[t]wice-weekly billing and settlement is likely to cause more uncertainty regarding bills, which may result in costly and time consuming billing corrections."

"A shortened settlement cycle can also introduce a disincentive for generation owners to sign bilateral agreements with LSEs," ConEdison Solutions added. "Typical bilateral contracts are also settled on a monthly basis. Receiving payment twice-weekly further reduces a generator's working capital requirements, and therefore their costs, when compared to delaying payment with a monthly bilateral contract settlement. Bilateral contracts are a valuable tool for LSEs to hedge future energy costs, reducing the overall risk and therefore the cost to end-use customers. Any reduction in the availability or increase in price of these contracts will inevitably lead to higher costs for end-use customers," ConEdison Solutions said.

Latest Calif. Draft on Resource Adequacy Still Poses Risk to Direct Access, AReM Claims

The Alliance for Retail Energy Markets criticized a revised California PUC proposed decision concerning resource adequacy, which would abandon the earlier multi-year forward commitment period in favor of the current year-ahead bilateral approach, for ignoring the "most central tenet" of the Bilateral Trading Group's approach (on which the revised draft is based) -- an energy-only approach to resource adequacy (R. 05-12-013).

As only reported in *Matters*, the revised draft incorporated concerns retail suppliers had with a multi-year forward commitment under a bilateral approach, and would retain a year-ahead bilateral obligation with enhancements such as an electronic bulletin board (Only in Matters, 3/30/10).

While AReM supports the revised draft's recognition of the harm to retail suppliers from a multi-year bilateral approach, AReM argued that the revised draft, "introduces equally serious threats to competition," by "institutionaliz[ing] the very type of utility procurement that Commission policy has recognized will compromise the success of competitive wholesale and retail market."

Essentially, AReM argues that without the high offer caps and scarcity pricing inherent in an energy-only approach, no merchant generation will be developed in California (absent a centralized capacity market, which AReM is also amendable to). "[T]he ultimate end state arising from the Revised PD will be a 'market' controlled by utility-owned and controlled generation, paid for by all, with an ever-declining portion of the consumer's energy bill subject to retail 'competition.' There will be no incentives for individual merchant investment because of the inability to compete with utilities' investment that is afforded guaranteed cost recovery and rates of return. Similarly, there will be no influx of retail competitors because the value proposition they can offer will be burdened by utility charges that require customers to pay for the utility supply portfolios," AReM said.

On this point, the California Forward Capacity Market Advocates made similar arguments, with the group consisting of San Diego Gas & Electric, Southern California Edison, NextEra Energy Resources, NRG Energy, and RRI Energy.

"Not only does the Revised PD place the business of IOUs and IPPs at risk, its vision of the future is ultimately corrosive to direct access. Direct access is intended to provide consumers choice - choice of supply resources, choice of price. Yet as more and more of the state's generation resources are procured by the IOUs through their LTPP [Long Term Procurement Planning] processes, and fewer merchant resources remain on the system, what choices remain? Without choice, what then is the purpose of direct access? Moreover, if nearly all capacity resources are under contract to the IOUs, direct access providers will have little choice in meeting their RA requirements but to purchase capacity from the IOUs; absent any capacity prices developed in competitive and transparent markets, however, both parties to such transactions will have little confidence that the contract capacity price is just and reasonable. These problems, along with the goal of retaining direct access as a viable choice, will put pressure on the Commission to allow broader opt-outs to the CAM [Cost Allocation Mechanism], shifting cost responsibility for legacy resources built for system needs to the subset of the utilities' bundled customers," the capacity market advocates said.

Pacific Gas & Electric, whose multi-year forward bilateral approach was first accepted in the initial proposed decision only to be jettisoned, argued that, [i]mposing a multi-year requirement solely on the IOUs, through the LTPP process, and not on all providers is inconsistent with a competitive retail market. Direct access providers may prefer the simplicity and artificial cost advantage of a business model that does not include a multi-year resource adequacy obligation."

"[D]irect access providers have demonstrated successful compliance with the current one-year resource adequacy requirement without harm to the retail market. There is no reason to believe that direct access providers cannot successfully transition to a multi-year obligation without harm to competitive retail market as well," PG&E said.

Briefly:

Constellation to Buy 1,100 MW of Gas-Fired Generation in ERCOT

Constellation Energy announced Friday that it signed an agreement with Navasota Holdings to purchase two natural gas combined-cycle generation facilities in Texas for $365 million ($332/kW). The purchase price is subject to closing adjustments. The transaction includes the Colorado Bend Energy Center, a 550-MW facility near Wharton, Texas, and Quail Run Energy Center, a 550-MW facility near Odessa, Texas. Colorado Bend and Quail Run, both within ERCOT, each have 275-megawatt expansion projects in advanced development. The acquisition is the first significant purchase since Constellation announced a strategy to match its retail load obligations with physical assets over a year ago, with Constellation later committing $1 billion to the endeavor (Matters, 8/3/09). The acquisitions are expected to close in the second quarter of 2010.

FERC Requests More Info from CAISO on Proxy Demand Resources

FERC directed the California ISO to provide additional information concerning its Proxy Demand Resource proposal, meant to comply with Order 719's directive to permit the aggregation of retail customers in bidding demand response directly into the wholesale market (ER10-765). Among other things, FERC directed CAISO to justify why the Proxy Demand Resource Energy Measurement - and, therefore, a portion of the associated cost of the Proxy Demand Resource's participation - is directly assigned to only the load-serving entity with which the Proxy Demand Resource is associated. FERC also asked how any potential market revenue shortfalls related to the participation of Proxy Demand Resources in the CAISO markets will be allocated.

Texas ... *from 1*

resources (other than solar resources), and 75 MW from solar resources;

- 6,225 MW of renewable resources in 2014, including 300 MW from new non-wind renewable resources (other than solar resources) and 75 MW from solar resources.

Solar resources would be categorized as Tier 1 resources, and could be used to meet any of the RPS tiers. Non-wind, non-solar resources would be Tier 2 resources, and could meet any non-solar requirement. Tier 3 resources would be wind resources; but as indicated the Tier 3 requirement could be met with either a Tier 1, Tier 2 or Tier 3 REC.

Staff's proposal would establish an alternative compliance payment (ACP) of $120 per megawatt-hour of deficiency in the solar (Tier 1) requirement, versus the strawman's ACP of $100. Staff recommended an ACP of $60/MWh for Tier 2 obligations, versus $40 in the strawman. Though the Staff proposal for publication says that the overall renewable compliance obligation can also be met via an ACP, there is no ACP listed for Tier 3 RECs, aside from the current penalty of $50/MWh. The penalty for failure to procure Tier 1 or Tier 2 resources or pay the ACP, would be double the ACP.

For the solar and non-wind, non-solar tiers, only resources installed after January 1, 2010 would be eligible to generate RECs. The strawman had used a vintage date of January 1, 2005. However, for Tier 3 resources (wind), the Staff draft would remove the current vintage date of September 1, 1999.

For the 2011 and 2012 compliance periods, the capacity conversion factors for non-wind, non-solar renewable energy technologies would be 90%, and the solar capacity conversion factor would be 25%. After those years, the capacity factors would be set based on actual generator performance data.

Under Staff's draft, a renewable energy storage device that discharges electric energy may generate a renewable energy credit of any tier for the energy it discharges if the operator has retired a renewable energy credit of the same tier in connection with charging the storage device for each megawatt-hour of energy it discharges. A renewable energy storage device would be defined as a facility using electric storage technologies to store renewable energy, with examples including batteries, flywheels, pumped hydropower storage, and compressed air energy storage.

Additionally, any production of gas from biomass within Texas that is delivered into a gas transmission or distribution system and used as fuel in an electric generating facility whose owner is registered as a power generation company would be eligible to produce Tier 2 or 3 RECs based upon the conversion of the thermal energy in BTUs to electric energy in kWh, using for the conversion factor the system-wide average heat rate of the gas-fired units of power generation company as measured in BTUs per kWh.

The draft would maintain the current process to allocate to each retail load serving entity its RPS obligation, except that the current offset concept would be eliminated, consistent with the elimination of the vintage date for Tier 3 resources.

Calif. ... from 1

if any customers whose NOIs were accepted fail to submit a proper switch request in that timeframe.

Suppliers have asked that these wait-listed customers be given more time to execute their direct access service request, as currently, the open enrollment window would close on June 30, prior to the 60-day switching period expiring on July 5 (see Matters, 3/29/10). If such relief is granted, six-month NOIs to take direct access effective in Year Two of the phase-in would be accepted by the utilities starting July 15 (if not, July 1).