Energy Choice Matters

June 2, 2008

CMP Attacks Subsidizing Retailers' Acquisition Costs

Central Maine Power is not willing to simply allow green energy suppliers to shift the costs and burdens of customer acquisition and enrollment to utilities, it told the Maine PUC in reply comments regarding use of utility bills to promote renewable energy (2008-178, Matters, 5/19/08).

CMP opposed the Retail Energy Supply Association's suggested check-off enrollment process for green products to be listed on utility bills. CMP argued that a brief description of the product on a bill is insufficient to meet the minimum requirements that should be necessary for customer enrollment and suggested something more contractual in nature.

"RESA's proposed process would completely shift enrollment and possibly competitive supplier customer service functions to T&D utilities," CMP added.

"Although it is easy to understand why competitive suppliers would like to avoid such costs and obligations, shifting them to T&D utilities is not the right answer. Customer procurement costs are inherent in the competitive market and, as such, are properly borne by competitive suppliers," CMP reasoned.

While CMP agrees that a new EDI process would be necessary for REC products, it thinks the EDI transaction should be initiated by the supplier rather than the T&D utility, consistent with current supply options.

The PUC should give "little weight" to RESA's positions, CMP insisted, because CMP thinks RESA mischaracterized SOS in the state, where the utilities merely provide billing and payment services to standard offer providers selected by a PUC procurement process, rather than providing SOS

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FERC Approves CAISO Backstop Capacity Mechanism, But Clips ISO's Discretion

FERC conditionally accepted the California ISO's Transitional Capacity Procurement Mechanism (TCPM) as a short-term bridge between the current Reliability Capacity Services Tariff (RCST) and the proposed Interim Capacity Procurement Mechanism (ICPM) that's to start concurrent with the Market Redesign and Technology Upgrade (ER08-760).

The biggest change FERC ordered was to Significant Event designations, as the Commission ruled that the CAISO had excessive discretion. FERC was concerned that the CAISO proposal lacked an objective benchmark that would require CAISO to designate capacity resources. Failure to designate TCPM capacity resources appropriately could result in discriminatory treatment among classes of generators, where resources that lack resource adequacy contracts or reliability must run (RMR) agreements receive insufficient compensation for the reliability services they provide, FERC explained.

CAISO is to incorporate an objective criterion and provide units with a minimum 30-day capacity designation upon the first commitment under the must-offer obligation. That will ensure non-discriminatory treatment between both resource adequacy resources and units under RMR contracts, on the one hand, and non-resource adequacy resources on the other hand, the Commission concluded.

FERC also rejected CAISO's use of a 10% adder on top of the inflation adjusted RCST capacity

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CL&P Files July 1 Standard Service, Last Resort Rates

Combined Standard Service generation service charges (GSC) and the bypassable federally mandated congestion charge (BFMCC) would slightly rise at Connecticut Light and Power July 1 under an application before the DPUC (08-05-14). Generation Service Charges alone would actually fall due to previous overcollections, but an increase in the BFMCC would result in a higher comparison price. While CL&P's laddered portfolio only produced a slight bump in small customer rates, Last Resort Rates would jump an average of 4¢/kwh since 100% of power is bought quarterly.

Proposed CL&P Rates
Standard Service Rates
July 1 2008 - Dec. 31, 2008

Class	GSC plus BFMCC (¢/kWh)
Rate 1, 5	11.793
Rate 7	14.320 On Peak
	10.820 Off Peak
Rate 18, 30, 35, 40	11.970
Rate 27	14.022 On Peak
	11.022 Off Peak
Rate 41*, 55*, 56*	14.300 On Peak
	11.300 Off Peak

Last Resort Service Rates
Rates 41*, 55*, 56*, 57, 58

Month	GSC plus BFMCC (¢/kWh)
July	17.660 On Peak
	13.735 Off Peak
August	17.883 On Peak
	13.971 Off Peak
September	15.219 On Peak
	13.079 Off Peak

*Customers in Rates 41, 55 and 56 may be either Standard Service customers or Last Resort customers based on demand.

RPM Buyers File FERC Complaint Over Transitional Base Residual Auctions

Led by the Maryland PSC, RPM Buyers filed a complaint at FERC (EL08-67) alleging that PJM's transitional Base Residual Auctions, "were no more than an enormous and unwarranted wealth transfer from customers in the PJM region to existing capacity resources."

Reiterating previous arguments, RPM Buyers claimed the $26 billion costs for the first four BRAs did not fulfill FERC's goal of a "measured rather than an immediate" price escalation that would "mitigate large cost shifts and rate effects."

RPM Buyers asserted an "absence of price discipline provided by new capacity resources and the ability of existing resources to withhold some capacity within the RPM rules combined to produce capacity prices in the transition period that are not comparable to those that would be produced in a competitive market or determined under cost-based regulation."

Although the PJM market monitor found the BRAs to be competitive, RPM Buyers rejected that characterization, arguing that actual rivalry among capacity suppliers seeking to obtain capacity payments did not occur.

RPM Buyers insisted that since mitigation was required (as every zone was structurally noncompetitive in the BRAs), "any legitimacy of the transitional auctions rests entirely on the efficacy and accuracy of administrative mitigation measures that PJM used in an attempt to replicate the results of true competition."

The administrative "stand-ins" for competitive offers, "were not up to the task," RPM Buyers argued, alleging that the, "auction results demonstrate that existing suppliers could and did exercise sufficient discretion within the RPM rules to make offers that inflate capacity prices."

RPM Buyers also cited the local deliverability areas as creating additional opportunities for sellers to raise prices while serving no legitimate function during the transition.

Hess Pushes for EDI-Provided ICAP Tags at Bangor-Hydro

Hess urged the Maine PUC to require utilities to provide competitive retailers with ICAP tags, preferably via EDI, because of the "central role" the tags play in matching customers to customized demand response, green and other products (2006-661, 2005-554).

Hess made the recommendation in response to PUC questions on smart meters and Bangor Hydro-Electric's advanced metering plan (Matters, 5/7/08), arguing that the two most critical elements of successful smart meter deployment are the ability of customers to see and respond to market reflective price signals, and the ability of meters to furnish hourly or more frequent usage data to customers.

Thus, utilities should make hourly data from advanced meters available on their website by the next day, Hess urged.

Hess believes the most effective dynamic pricing program for medium and large C&Is would be mandatory hourly priced default service. While Bangor-Hydro is not pursuing mandatory hourly pricing, Hess suggested that an opt-out hourly pricing program is preferable to a model where customers must opt-in to take hourly prices.

MEA Stresses Aggregation as Key to Small Customer Solar Market

The benefits from potential enhancements to Maryland's solar REC program (Matters, 5/7/08) will be limited unless the state can develop a fully functioning market for residential and small commercial solar RECs, the Maryland Energy Administration told the PSC (RM32, PC11).

Such a market is unlikely to develop without aggregation of residential and small commercial customer solar installations, MEA reiterated, prodding the PSC to examine how to promote such aggregation.

MEA suggested a utility surcharge to pay for market enhancements (such as generator training, a price reporting system, and a customer service hotline) because increased solar generation would reduce capacity costs for all customers. Alternatively, fees from solar generators and aggregators could fund the programs, MEA noted. Such fees, though, would have to be "fairly modest" to avoid undermining the solar RPS program, MEA stressed. Revenues from RGGI emissions credits, if available, may also be used to fund the enhancements.

Baltimore Gas and Electric noted that it appears that the PSC and MEA have potentially overlapping responsibilities for the solar industry. BGE urged the PSC to consider which agency is best suited to provide the enhanced services that stakeholders are seeking, noting that MEA already provides grants to residential and small commercial customers to offset some of the costs of installing a solar generating system.

BGE suggested that the PSC should consider partnering with MEA to provide a "one-stop-shop" to provide support for residential and small commercial solar installations.

Allegheny Power, noting that federal tax credits and RPS already provide incentives for renewable generators, urged the PSC to allow market mechanisms to steer cost-effective development of competing renewable and other generation sources. "Loading special 'services' into the cost of providing one type of renewable, such as solar, will tend to retard, rather than promote, cost-effective use of those resources by end-use customers," Allegheny argued.

Allegheny also insisted it would be unfair to impose costs to support solar on its customers, given its service territory does not have the sunshine to make it attractive for large-scale solar development, and thus its customers would not see commensurate benefit from promoting such development.

Allegheny saw little need to fund many of the requested enhancements. Brokers, Allegheny noted, have already provided price reporting in New Jersey's solar market and will likely perform the same service in Maryland. A regional bulletin board and automated production tracking system are already provided by PJM GATS, Allegheny pointed out, and those services should not be duplicated. Training should be handled by individual solar developers, the utility added.

Briefly:

PJM May Propose Continued Role for MMU in RPM Tariff Administration

PJM may request authority to preserve the existing allocation of functions for its market monitor if a final FERC rule on market monitoring takes monitors out of the role of tariff administration (Matters, 2/22/08). The RPM settlement allocates certain tariff administration and implementation duties to the market monitor, and as a carefully balanced compromise, PJM is to carefully consider with stakeholders whether the interests in preserving parties' expectations to the RPM bargain might outweigh the benefit of a uniform application of the MMU’s role espoused by FERC's proposed rule (RM07-19).

WhiteFence Creates Texas Specific Site

Utility comparison website WhiteFence launched a Texas-specific power shopping website, ElectricChoiceForTexas.com. The participating REPs are the same as those on WhiteFence's main site - Amigo Energy, Commerce Energy, Direct Energy, First Choice Power, Green Mountain Energy, MXenergy, Reliant Energy, Simple Energy, TXU Energy, and Texas Power.

Calpine Says NRG Offer Undervalues its Portfolio

Calpine rejected NRG Energy's unsolicited, $11 billion takeover offer as inadequate, but left the door open for future talks (Matters, 5/22/08). NRG CEO David Crane, while still interested in a merger, said it would be on the terms NRG had proposed.

N.J. LDCs File Higher Commodity Rates

New Jersey LDCs moved to pass along higher natural gas commodity costs to customers in annual supply filings. PSE&G would raise residential gas bills 20% effective Oct. 1, while New Jersey Natural Gas asked for an 18% increase. Elizabethtown Gas would raise its commodity rate from $1.0339/therm to $1.3561/therm.

FERC OKs PJM Day-Ahead Scheduled Reserves Market

FERC accepted PJM's Day-Ahead Scheduled Reserves (DASR) supplemental reserves market, finding that the co-optimization process will give baseload and intermediate generation greater opportunity to provide reserves than under current rules, and will open the reserves market to demand response (Matters, 5/7/08, ER08-780). That should reduce PJM's reliance on peaking generation (and thus lower costs), rather than increase the use of peakers as the Maryland PSC had suggested. FERC conditioned approval on PJM submitting a compliance filing to accommodate batch loads in the DASR market in a manner similar to that used for batch load participation in the synchronized reserves market.

Texpo Files to Update Trade Names

Texpo Power asked the PUCT to approve a new trade name of Southwest Power & Light and to discontinue use of the trade name TexPower Electric Company (35733).

Parties File Settlement on New England Bid Mitigation Agreement Costs

NEPOOL, ISO New England, generators and transmission owners have filed a settlement regarding Bid Mitigation Agreement charges that pre-dated the ISO's standard market design in 2003. The pact would have generators and power marketers pay about $2 million to those transmission and distribution providers who passed the charges onto retail customers, with refunds flowing to retail customers. Distribution of funds would not go to suppliers of power procured for the benefit of retail customers. NSTAR's utilities would receive about $500,000 combined, National Grid $400,000 and Northeast Utilities $134,000, with smaller amounts to other New England transmission owners. The pact would resolve all claims under docket EL01-93 and associated cases. The Bid Mitigation Agreements paid certain generators above-market costs for reliability reasons.

PJM Gets More Time for External MMU

FERC granted PJM's request to delay the implementation of its external market monitoring unit since more time is needed to fully test and finalize Monitoring Analytics' computer systems and prepare its new office space (Matters, 5/13/08, EL07-58). Originally due to start June 1, the external unit is now to begin sometime before Dec. 1.

N.Y. PSC Asks About Utility Energy Efficiency Incentives

The New York PSC solicited comments regarding whether, and to what extent, performance-based financial incentives should be established prior to the submittal of energy efficiency proposals by utilities (07-M-0548, Matters, 5/22/08). Stakeholders are asked to comment on several models, including those of the staff as well as rules developed by the California PUC.

FERC Approves Higher FTR Credit Rules in MISO

FERC accepted the Midwest ISO's changes to its financial transmission rights credit policy (ER08-622, Matters, 5/7/08). The MISO plan changes the method of calculating the estimated exposure associated with holding FTRs acquired through an FTR auction, and the new exposure resulting from the changes to the settlement process of the FTR auction transactions, including the implementation of Auction Revenue Rights. MISO must continue to review FTR credit policies and report to FERC every 90 days.

CMP Green Billing ... from 1

themselves.

CMP also attacked a proposal from Competitive Energy Services and Maine Interfaith Light and Power that would require utilities purchase suppliers' receivables at a defined discount to face value. POR is, "far beyond the proper scope of this proceeding," CMP observed, and would force utilities to assume the collection risk associated with green supply and REC products. POR, "would unfairly shift risks that were designed to be, and are properly borne by, entities that choose to participate in the competitive electricity market," CMP contended.

CMP is also opposed to a, "broader initiative whereby its billing envelope would be made available to a wide range of supplier products and services." CMP noted that RESA had suggested the PUC's treatment of renewable products be extended to similar environmentally friendly services, such as demand response and energy efficiency products offered by suppliers.

CAISO TCPM ... from 1

price, ruling the ISO failed to support the adder's reasonableness. FERC determined the inflation-adjusted price of $77.89/kW-year remains within the reasonable range.

The Commission reiterated that backstop capacity procurement is not intended to promote the construction of new generation and that the anticipated short-term nature of the TCPM does not provide the long-term incentive required to attract new investment. Thus, the capacity price should not reflect cost of new entry, FERC observed.

FERC denied pleas from the Alliance for Retail Energy Markets and Constellation that the CAISO provide resource adequacy credits for TCPM capacity.

"If the CAISO were to allow LSEs to count capacity resources corresponding to a Significant Event towards their resource adequacy requirements, it would result in no additional procurement of capacity. Instead, it would result in TCPM capacity displacing the capacity resources that should be procured under the resource adequacy program," FERC reasoned.