Energy Choice Matters

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APPA: Ratebased Generation Not Our Solution

APPA is not proposing a return to ratebased regulation, CEO Mark Crisson told a NARUC panel yesterday, stunning EPSA CEO John Shelk and other competitive market participants in the room.

APPA is not interested in trying to eliminate competition either, Crisson added.

That prompted Shelk to note that such sentiment is not what Crisson's predecessor, Alan Richardson, had said. Shelk congratulated the muni group on moving forward.

APPA, Crisson said, actually wants to bring competition to places where it doesn't exist in a meaningful way.

Crisson reminded regulators APPA thinks RTOs perform a lot of valuable functions such as providing de-pancaked transmission rates and day-1 and balancing markets.

APPA members were pushing for open access before there were IPPs, Crisson reminded.

But APPA really doesn't like the day-2 markets.

APPA later this month will have some specific suggestions once a white paper is completed as part of its Electric Market Reform Initiative.

But the cost of building new power plants is rising even faster than the cost of power, Shelk warned. He pointed to a recent CERA study showing plant costs rose 27% from August 2006 through August 2007, with a staggering 20% rise in the last six months of the span.

Plant construction costs are 130% higher than they were in 2000, meaning a plant that cost $1 billion then would now cost $2.3 billion.

A lot of those costs stem from astronomically higher cement, steel and copper costs, Shelk noted – manufacturers who signed onto a petition by APPA for FERC to investigate organized markets. Power is more expensive because those industrials are passing on higher raw material costs to power producers, yet they are complaining about the resulting high power prices, Shelk mused.

... Continued Page 4

RESA Wants Customer Lists Back in RM17

The Retail Energy Supply Association is reminding the Maryland PSC that stakeholders worked for over two years to get a compromise on reformed billing and enrollment rules, and the state's retail market needs final action for competitive suppliers to be able to offer customers new choices and alternatives to SOS.

Rulemaking 17 was first noticed by the PSC way back in July 2005. As currently written, it would let utilities either purchase marketers' receivables or pro-rate partial payments to bring parity to treatment of bad debt; would allow retailers to submit drops and enrollments 12 days before a meter read (as opposed to 35 and 17 days, respectively); and allow retailers to notify utilities of enrollment errors before actual enrollment.

It was sent to the state's Joint Committee on Administrative, Executive and Legislative Review (AELR) once before, but died there as AELR opposed selling customer lists to retail marketers. Consideration of the rules automatically expired one year after being published, so the PSC this fall published a revised set of rules, deleting the sale of customer lists.

RESA told the PSC it should reinstate language that would let utilities sell customer lists to retail suppliers. The lists, RESA reminded, do not include confidential information such as social

... Continued Page 5

Exelon Wants to Know How Duquesne Portable Capacity Would Work

FERC has to answer a lot of questions about how "portable" capacity will work once Duquesne Light leaves PJM for the Midwest ISO, Exelon told the Commission (docket ER08-194).

Exelon called portable capacity the "most novel and also the most alarming" idea in FERC's withdrawal order.

What that means is Duquesne may be able to use capacity bid into PJM's Reliability Pricing Model auction for delivery years 2008-2010 to satisfy reliability requirements other than those under RPM, such as those in MISO.

The same procedures will apply to other load serving entities (LSEs) who are responsible for capacity in the Duquesne zone.

Portability remains an "amorphous" concept, Exelon cautioned, urging the Commission to clarify its intentions.

Exelon explained that suppliers whose bids clear in the RPM capacity auctions must offer the energy associated with that capacity into PJM's Day-Ahead (DA) market.

Load's responsibility to pay for capacity does not entitle it to any unrestricted right to the energy.

Rather, capacity suppliers have an obligation to offer energy into the DA market and load simply has the opportunity to purchase energy in the DA market, Exelon noted.

Exelon wants FERC to clarify what rights and obligations LSEs in the Duquesne zone have with respect to the opportunity to purchase energy in PJM's DA market due to their ownership of portable capacity. FERC should also clarify the rights and obligations of the identified portable capacity to offer energy into the DA market.

"Duquesne and other LSEs should have no greater rights to purchase energy in the DA market than they would have if they remained in PJM," Exelon stressed.

PJM's RPM capacity market is not unit specific, Exelon reminded, so Duquesne and other LSEs have no entitlement to specific capacity with which to satisfy resource requirements in MISO.

MISO requires LSEs to designate network resources (DNRs) to satisfy reliability requirements, and DNRs have an obligation to bid into the MISO DA market.

But since the capacity purchased by LSEs in the Duquesne zone is not unit specific, it is unclear how to determine what units, if any, would bid into the MISO DA market, Exelon noted.

Exelon pointed to different reserve margins between the RTOs, since MISO has a 12% reserve requirement but the RPM auction cleared above 12% for the Duquesne zone for every planning year Duquesne is assigned RPM capacity.

Thus, to the extent Duquesne "acquired" more capacity than is needed to meet the Midwest ISO's reliability requirement, can Duquesne resell such capacity in the Midwest ISO, Exelon asked.

Exelon wants to know how Duquesne will ensure that the cleared RPM generators located in the Duquesne zone have firm transmission "into" PJM and that the generators qualify as an "external resource" for RPM purposes.

FERC also needs to address impacts on Auction Revenue Rights (ARRs) and Financial Transmission Rights (FTRs) since Duquesne's exit will split historic resources and historic zonal load used to give preference in rights allocation.

Exelon asked FERC to clarify that for the May 2008 RPM auction that generators connected to the Duquesne system will not be in PJM for that auction (as well as subsequent RPM auctions for delivery years in the future) and may participate in those RPM auctions only if they satisfy all the requirements for a capacity resource located outside of PJM, just as any other generator in the Midwest ISO seeking to qualify as an RPM resource.

Finally, Exelon wants to know what happens if Duquesne does not fulfill all the requirements to leave PJM by the 2011-12 delivery year, since the Duquesne zone is being excluded from the May 2008 auction to procure capacity for that delivery year.

Powerex Cautions Against Duplicate Credit Postings due to MRTU Delay

While Powerex believes a contingency plan by the California ISO to deal with Congestion Revenue Rights (CRRs) that won't go into effect as scheduled due to the delay of the Market Redesign and Technology Upgrade is "generally reasonable," Powerex wants to make sure the CAISO does not use duplicative credit requirements.

CRRs are replacing the old Financial Transmission Rights (FTR) system and were to start coincident with the implementation of MRTU April 1.

But with MRTU's delay, the CAISO wants to conduct a new FTR auction that will release FTRs from April 2008 through March 31, 2009. The CAISO also plans to reduce the terms of, and resettle payments for, currently released CRRs beginning in April 2008, up until the new MRTU implementation date.

Powerex is concerned that the CAISO did not make clear the exact credit posting and payment timelines for those two events, and told FERC (docket ER08-519) that the ISO does not specify how it will address any overlap in credit or payment requirements.

"This could result in market participants having to make duplicative credit postings for both FTRs and CRRs, only one of which will actually be in effect at any given time," Powerex explained.

The CAISO should clarify that a market participant that holds CRRs and that plans to purchase new FTRs should have to maintain the appropriate amount of credit for the larger of the two obligations, but not for both obligations, Powerex argued.

The Citadel Energy companies want CAISO to pay interest on refunds for the CRRs whose terms are reduced — not just from the expected April 1 start date until the MRTU start date, but from the date of original payment.

Citadel on Jan. 3 paid the CAISO over $22 million for CRRs, it told FERC.

The hedge fund affiliates are "incurring substantial costs" on capital which is tied up without any countervailing opportunity to earn a return on their investment for an indeterminate period of time, Citadel explained.

Calif. PUC Clearly Wants Competitive Solicitations, IPPs Say

A proposed decision by a California PUC ALJ is correct to require Southern California Edison to conduct a competitive solicitation for the construction of a Clean Hydrogen Power Generation plant, should a feasibility study determine a plant would be technically viable, the Independent Energy Producers Association (IEP) said (07-05-020).

While noting a PUC decision in D.07-12-052 does allow for limited utility-built generation in extreme circumstances, the PUC clearly stated its preference for competitive procurement, IEP noted.

The PUC's order maintained a "competitive market first" approach and only allows utility owned generation in extraordinary cases, after the utility has shown a competitive solicitation isn't feasible. SCE has made no such showing, IPPs argued.

SCE is caught by its own logic, IEP reasoned. SCE wants a feasibility study to determine if the hydrogen plant is commercially reasonable, IEP observed. But SCE then says it needs to build the plant itself because the technology is experimental and merchant generators could not handle it.

SCE can't have it both ways, IEP scolded.

Either the plant is "commercially reasonable," meaning any party should be able to build and operate it; or the plant isn't commercially viable, and SCE is asking ratepayers to bankroll unproven technology, IEP argued.

"SCE's argument puts it in the awkward and unsustainable position of arguing that the plant will be 'commercially reasonable' for SCE, but not for its competitors," IEP observed.

The PUC has also rejected viewing debt equivalence as a cost incurred by utilities when entering into purchased power agreements, IEP noted in rebutting SCE's claim that using a competitive solicitation would have negative financial impacts.

Eight-Year Old Congestion Charges Still Have Mass. Wholesaler Fuming

Wholesaler Alternate Power Source wants the Massachusetts DPU to reverse what it considers an eight-year old wrong and make Western Massachusetts Electric (Northeast Utilities) pay for congestion fees as part of standard offer generation service from 2000 (docket 08-3).

The DPU had approved a tariff that did not include transmission costs in the SOS rate, which only included generation costs. That made Alternate Power Source as an SOS supplier responsible for $1.8 million in transmission congestion charges.

Alternate Power Source believes such a decision is inconsistent with other unbundling orders and goes against precedent set in a Fitchburg Gas & Electric case. The DPU had previously dismissed Alternate Power Source's complaint as the case was also being litigated in court and the DPU felt the wholesaler was forum shopping. The courts ruled against Alternate Power Source.

Alternate Power Source alleges WMECO committed "fraud" before the DPU when the utility said it was following a directive to model its SOS after the Fitchburg decision which, according to Alternate Power Source, would have made end users, not wholesale suppliers, pay for congestion. Comments are due March 7.

Briefly:

Interconnection Reform Among Top FERC Priorities

FERC is going to move as quickly as possible to vet and approve RTOs' revised interconnection polices, Commissioner Suedeen Kelly and FERC staff told NARUC delegates. Kelly was giving regulators an update on FERC's work to fix the broken interconnection process and reviewed the impetus for a December technical conference. Since FERC has resisted a one-size-fits-all approach to interconnections, and is allowing RTO stakeholders to develop unique plans, she hopes consensus can be reached before proposals come to FERC so the plans can be moved quickly. But the Commission won't rush if some stakeholders have problems with the reforms. Kelly expects many of the working proposals to be filed with FERC in the coming month or so will allow interconnection requests to be bundled so the first generator in line doesn't pay for all the grid upgrades that later power plants will benefit from.

Integrys Tells FERC to Wait on Moving RSG Case Forward

A Feb. 1 Midwest ISO compliance filing on real-time Revenue Sufficiency Guarantee (RSG) charges left out the most important element of any just and reasonable rate – the cost causation justification for the rate design, Integrys Energy Group told FERC (EL07-86 et. al.) Thus it's premature for Integrys to address MISO's proposal substantively, and Integrys urged FERC not to set the case for paper hearing until a March 3 filing from MISO that will contain specific tariff language and supporting documentation. MISO has been working on reforming the RSG process for nearly three years, and their applicability to virtual transactions has been a hot case at FERC. The fees are paid to generators which come online to meet reliability needs in the Reliability Assessment Commitment (RAC) process to ensure generators' start-up and production costs are recovered.

APPA … From 1

With everyone worried about carbon, and experimental technology being pursued to reduce greenhouse gas emissions, ratepayers should not pay for the mistakes in testing out new technology, Shelk argued.

Plants with new technology shouldn't be built by companies that make more money the higher the plants cost, he added.

If you need heart surgery, you don't go to a surgeon who only does surgery once a year, Shelk noted, you go to the doctor who does it every day. IPPs compete to drive down costs daily to survive, and have a history of bringing new technologies online at a lower cost because they're fighting against their competitors. Utilities don't have that history of keeping costs of new technologies low, he observed.

Capital needed for investment will only flow to stable markets, Shelk cautioned. He argued sustained market-based rates are needed, and regulators can't rush in to mitigate the results of capacity auctions in the eastern RTOs, he added.

Markets without capacity markets, or some other form of mandated resource adequacy, need to implement a capacity market if those markets have overly mitigated energy prices, Shelk said.

RM17 … From 1

security numbers, utility account passwords or customer telephone numbers – only customer name, address, utility account number, utility rate class, utility SOS type. Customers could also opt out of being included on the lists.

Retailers need the lists to reach mass market customers, RESA explained, noting Washington Gas Energy Services had told the PSC it was unable to offer certain specialized products in Maryland because of WGES's inability to obtain valuable customer information.

"Thus, the delay in adopting the proposed regulations and ... subsequent deletion of the customer list provision has already deprived residents of valuable product offerings and savings," RESA noted.

RESA urged the Commission to reject Baltimore Gas & Electric's proposed COMAR 20.53.05.03.F, which was suggested unilaterally at a Nov. 28 hearing on the rules and did not come from the working group process.

BGE's rule would direct utilities providing consolidated billing to place charges disputed by customers in escrow until the Commission rules on the dispute.

The provision raises more questions than answers, RESA noted.

RESA wondered whether retail suppliers will receive payment prior to any administrative resolution of the dispute, especially when the dispute does not relate to retail supplier charges.

May the utility initiate termination proceedings under COMAR 20.32.01.03 while the dispute is being resolved, RESA asked.

The "vagueness" of the rule invites the Commission to reject it, RESA argued.