Energy Choice Matters

July 10, 2008

Smitherman Thinks AMIN Would Fail on Vote as Filed

Although he could not be sure, PUCT Chairman Barry Smitherman doesn't think CenterPoint Energy has the votes on the Commission to win approval of its Advanced Meter Information Network (AMIN) program as filed, the Chairman stated at the close of a hearing on AMIN (35620, Matters, 6/30/08).

Smitherman urged the parties to take another shot at settlement, and Commissioners suggested a 125,000-meter cap on meters permitted under AMIN to give some guidance on one of the largest roadblocks to settlement.

Commissioners largely dismissed the concerns of REPs other than Reliant Energy that Reliant received an unfair advantage in working with CenterPoint to draft the AMIN agreement.

However, Commissioners did have problems with several other aspects of the program that they felt could inhibit customer choice.

Smitherman thinks REPs which win customers who have AMIN meters away from the REP which originally installed the meter should not have to pay for that meter, or lose it by the customer's original REP deciding to remove the meter as permitted under AMIN. The market depends on easy switching, Smitherman noted, and he sees charging the customer's new REP for the meter as anticompetitive and an impediment to choice.

Commissioner Julie Parsley shared that concern, but also was worried about REPs poaching AMIN customers based on the provision of an ESI ID list of customers with AMIN meters, and asked that stakeholders address the issues.

Smitherman also suggested not allowing unique capabilities in AMIN meters, arguing that if REPs

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Retailers, TOs Warn of Market Distortion under N.Y. Staff Plan for Reliability Backstops

Regulated backstop solutions for reliability needs in New York would be evaluated by transmission owners and PSC Staff after the New York ISO issues its Reliability Needs Assessment (RNA) but before NYISO issues its Comprehensive Reliability Plan (CRP), under a proposal from Staff in an all-parties report regarding implementation of regulated reliability solutions (07-E-1507).

That timeline could harm the competitive market and create a greater reliance on regulated backstops, marketers and transmission owners warned, a major point of contention which prevented consensus on a PSC process to review and approve backstop reliability projects.

The CRP identifies whether market-based solutions will meet needs listed in the RNA.

Under Staff's timeline, when NYISO identifies a reliability need in the RNA and a regulated solution is proposed that would need to be triggered by the next RNA, responsible transmission owners and PSC Staff would immediately consult with the proponents of all alternative projects to review whether responsible transmission owners should modify the regulated backstop proposal, even before the CRP is issued. Responsible transmission owners would make the ultimate decision regarding whether to modify their regulated backstop proposal, either in whole or in part, to reflect the use of a regulated alternative solution.

Should the NYISO require a backstop project, responsible transmission owners would then move forward in seeking PSC approval for their chosen project, while proponents of alternative projects that wish to be considered further would have the right to concurrently submit their alternatives to the PSC.

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UI Wants to Buy Energy and RECs on Same Long-Term Contract

United Illuminating opposed a provision of the Connecticut DPUC's draft order which would allow electric distribution companies to sign long-term contacts for new Class I RECs, arguing that EDCs should not be prevented from contracting for energy and capacity when contracting for RECs (07-06-61, Matters, 7/1/08).

Such a limitation could prevent EDCs from striking the most advantageous offers, UI reasoned, reminding the DPUC that it recently approved EDCs to enter long-term bilateral contracts for energy and capacity. UI sees no reason that those products should be segregated from long-term REC contracts.

Although the draft notes long-term contracts for RECs would promote renewable development, which hedges the state against fossil fuel prices, the draft's prohibition on contracting for energy and capacity in the same contract as RECs would limit that hedge, UI added.

UI also asked the DPUC to allow REC contracts up to 15 years in length, the length contemplated by legislation, instead of 10 years as may be suggested by the draft.

The Office of Consumer Counsel urged the Department to clarify that long-term REC contracts must be reviewed in a contested case proceeding, and that the Department can modify contracts submitted for its approval, in addition to straight approval or rejection.

OCC remains concerned that a long-term contractual purchase of RECs may end up being a long-term purchase of nothing (or close to it), because of potentially rapid law and market changes in the next decade relating to carbon. OCC thus favors limiting the length of any REC contracts. Purchase of "all environmental attributes" should not be assumed to be sufficient protection for ratepayers in future contracts and future proceedings, OCC said.

Md. PSC Won't Wait Another Year for Sempra Catoctin Decision

The Maryland PSC explained that it refused to further extend the deadline for certain conditions contained in a CPCN for Sempra Generation's proposed Catoctin Power 600-MW power plant in Frederick County because Sempra's decision to not offer the capacity of the proposed plant in the May 2008 RPM auction means Sempra, "lacks the incentive to complete construction by 2011," when the power may be needed for reliability needs in the state (8997).

Citing the project's economics, Sempra decided not to bid the plant into the most recent RPM auction after FERC refused to raise the Cost of New Entry (Matters, 5/5/08). Sempra asked the PSC to extend the date for compliance with certain CPCN conditions, such as construction commencement, until 2009 when it would re-evaluate bidding into RPM.

But the Commission found that it is not in the public interest to extend, yet again, various CPCN conditions so that Sempra can, in essence, wait until May 2009 to see if market conditions are sufficiently attractive for the company to proceed - or, if not, to ask for yet another extension. Sempra acknowledged that building the Catoctin plant may not be viable in May 2009 either, the PSC noted.

"It would be nonsensical for the Commission to extend the conditions in the CPCN and allow a company that does not believe it is economically viable to build the facility to continue to sit on the rights to build," the Commission ruled.

Thus the PSC found that conditions of the CPCN have not been met, and Sempra would need a new air permit for the certificated power plant to be constructed.

In a separate statement, Commissioner Allen Freifeld suggested that there would have been no downside to extending the compliance deadline until July 24, the date at which Sempra would have to renegotiate an Engineering, Procurement and Construction (EPC) contract with the builder. A new EPC would likely raise the price of building the plant, Sempra said.

A brief extension of the expiration date of the CPCN, to be coincident with expiration of the EPC contract, might produce interest from another developer, without indefinitely tying up what all parties recognize as a valuable site, Freifeld noted, even though Sempra downplayed the possibility that another party would be interested in taking over the project in such a short time.

Briefly:

Pepco, Delmarva File Latest Type II Rates
Delmarva and Pepco filed with the Maryland PSC their latest Type II SOS generation rates for the quarter beginning Sept. 1

Type II SOS Rates, Sept. 1, 2008 - Nov. 30, 2008
Pepco:
MGT LV II: 14.070¢/kWh
MGT 3A II: 13.868¢/kWh
Prices are the same on-peak and off-peak.

Delmarva:
All Type II classes: 13.2710¢/kWh
Prices are the same on-peak and off-peak.

Parties Asked for Cost/Benefits of DWR Novation
California stakeholders were instructed to submit their full and final proposals regarding the exit of the Department of Water Resources from the business of supplying power as part of Phase II (a)(1) of the PUC's examination of lifting the ban on direct access (R. 07-05-025). An ALJ directed parties to submit detailed analyses regarding net costs or benefits of accelerating removal of DWR from its role as supplier of power under AB 1X. The analysis should consider the costs/benefits assuming complete removal of DWR from its role as power supplier for all remaining contracts as well as the potential costs/benefits of limiting novation/renegotiation only to a subset of contracts, if necessary to produce overall ratepayer benefits or to avoid ratepayer harm, a an ALJ said. Parties should incorporate into their estimates the following range of different cut-off dates: January, 2010; July, 2010; October, 2011; and July, 2012. DWR is to serve parties with updated data on reserves and administrative costs relevant to the cost/benefit calculation as early as possible during the week of July 14. Opening comments on net costs/benefits are due on August 4. Parties were also directed to submit proposals to allocate costs from ex-DWR contracts taken over by a utility or other entity to IOUs by July 28.

Grid, MI Want NYISO Reliability Fee Changed to Demand Charge
National Grid and Multiple Intervenors urged FERC to change a proposed New York ISO rate schedule (Reliability Facilities Charge or RFC) to recover costs of a regulated reliability transmission project from a volumetric rate based on an LSE's zonal energy withdrawal to a demand charge based on an LSE's contribution to the Zonal Peak (OA08-52-001). The change is needed to harmonize cost recovery with cost allocation, as costs of regulated reliability backstop projects constructed to address identified reliability needs are allocated on a demand basis to different load zones in accordance with a "beneficiaries pay" approach, Multiple Intervenors explained. Recovering costs associated with regulated reliability backstop projects on a volumetric basis would also be inequitable to large, high load factor customers since the identified reliability need, and associated cost allocation, are based on demand, MI added.

EnergyConnect Says It Processed Half of PJM Economic DR Settlements
EnergyConnect processed over 50% of the economic real-time and day-ahead demand response settlements for customers in the PJM region during the first quarter of 2008, the demand response provider said yesterday.

Boralex Gets More Ontario Wind
Boralex acquired the rights for a wind project with a potential installed capacity of 100 MW in the municipality of Chatham-Kent, Ontario. The farm is to be submitted into the Ontario Power Authority's Request for Proposal III for 500 MW of Renewable Energy Supply likely due this fall, Boralex said.

CenterPoint AMIN ... *from 1*

want additional special features, they could pay for them under current CenterPoint tariffs.

Commissioner Paul Hudson, despite noting the AMIN proposal had some, "hair on it," was the most supportive Commissioner for the program. Hudson suggested several conditions to make the program more agreeable, such as requiring CenterPoint to inform all REPs of where certain REPs are paying for the installation of cell relays.

One reason Smitherman refused outright endorsement of AMIN was because REPs, under current provisions of CenterPoint's tariff, could request and install advanced meters right now; they just would not be reimbursed for the costs.

Smitherman questioned CenterPoint's assertions that cash flow considerations would limit its own deployment of advanced meters outside of AMIN. Smitherman pointed out that CenterPoint's electric transmission and distribution capital expenditures for the first quarter of 2008 were $89 million, a decrease from $110 million in the year-ago quarter. The Chairman also suggested CenterPoint would have more cash if it stopped increasing its dividend.

Reliant Energy disclosed at the hearing that under a best-case scenario it would anticipate supplying 100,000 to 200,000 customers with smart meters under AMIN. Reliant would not charge customers for the meters, and, under its current plan, would not charge for related in-home devices to be used in conjunction with smart meters and new products, though it could later decide to charge for such in-home devices. Reliant explained that most customers would not accept paying for a meter as part of enrolling in a new innovative product, especially since the meter is owned by CenterPoint, not their REP.

Parsley would like to see all REPs not charge customers for AMIN meters.

N.Y. Backstops ... *from 1*

By beginning a review process for regulated solutions before the CRP is issued, Staff inadvertently signals to project developers and the marketplace that regulated generation projects (as well as demand response projects) are no longer a last resort, the Retail Energy Supply Association cautioned. RESA favors not beginning the TO-Staff informal review until after the CRP is issued.

Starting the review before then will institutionalize the review of regulated utility and non-utility projects and thus send a message that regulated solutions have become a "viable" option that may be considered by PSC Staff as an alternative to market-based solutions, RESA argued.

Transmission Owners agreed that the Staff's approach would create the risk that developers will begin to treat a regulated solution as a viable alternative business strategy to the development of resources on a market basis, instead of an unlikely event. The encouragement of regulated projects could feed on itself, transmission owners observed, as fewer market-based projects increase the need for regulated solutions. In turn, as more regulated solutions are actually triggered, the more they become a viable business alternative to more risky market-based projects.

Logistically, RESA also questioned the value of evaluating backstop solutions before the NYISO determines whether market solutions will fill the need, and suggested that such reviews would strain scarce PSC resources.

Staff explained that the review process would begin immediately after the RNA is issued because of the long lead time in building many reliability solutions. Waiting to start the review process could exclude potentially superior resources from consideration due to timing, Staff noted.

In December, the PSC concluded that, "utility long-term contracts may be required to support new construction to maintain reliability, if adequate reliability is not provided by the wholesale market or to be judiciously used to achieve other policy goals."

The Staff report recommends that the Commission should indicate that long-term contracts will be considered on a case-by-case basis, by weighing factors such as whether they are necessary in view of market conditions, the relevant benefits and/or negative impacts of specific proposals, the consistency with applicable NYISO markets, minimization of the risks and costs to consumers, conformance with applicable public policies, and the degree to which the proposed structure of the contract impacts the competitive markets.

Multiple Intervenors maintained that it is "critically important" that the process ultimately adopted by the Commission not create an incentive for developers to seek regulated projects in lieu of market-based projects.

Undue reliance on long-term contracts that are not cost-based may have the unintended effect of discouraging market-based projects if backstop solutions appear more attractive to developers, claimed Multiple Intervenors

Once projects proceed to the Commission for a formal review, the Commission would use two screens to evaluate projects. First, the PSC would determine the ability of the project to address the reliability need in a timely manner. Second, the Commission would evaluate the project's merits with regard to various public policy objectives, such as fuel diversity, generation diversity (e.g. baseload vs. peak), renewable and environmental goals, affordability, and overall benefits to New York ratepayers.

"Resource needs should normally be met by the market, and the process recommended by the report should not inadvertently favor the use of backstop solutions in lieu of market-based approaches," the report recommends.

The 2008 draft CRP indicates that the first identified reliability need date will be in 2013, although sufficient market-based projects have been identified to indicate that those anticipated needs will be met, Staff noted.