Energy Choice Matters

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Maine Industrials Press PUC to Pursue Hybrid Market Concurrent to Reforms at ISO-NE

The Maine PUC should direct Central Maine Power and Bangor Hydro-Electric to pursue the development of a "best hybrid" alternative to membership in ISO New England concurrent to their pursuit of reforms to the ISO-NE Transmission Operating Agreements, the Industrial Energy Consumer Group said in exceptions to a recommended decision (2008-156).

Two hearing examiners recommended that CMP and BHE pursue reforms to ISO-NE transmission cost allocation policy and governing agreements as the best alternative to the status quo. However, should such reforms prove unattainable, CMP and BHE should pursue development of a hybrid approach, under which they would participate in some ISO-NE functions a la carte, while joining the Northern Maine Independent System Administrator for other functions (Matters, 12/18/08).

IECG, which called the PUC's investigation the, "last, best hope for Maine to break the long, deadly cycle of unnecessary Maine electricity cost escalations caused directly and indirectly by ISO-NE," argued that development of the "best hybrid" model should not wait until the ISO-NE reform process has been exhausted.

"The Report's greatest error is in recommending a weak and limited continuing pursuit of the answers, thereby risking that the extensive work done by the Commission, the parties and the Legislature over the last several years will be wasted and the opportunity to break the long, deadly cycle of unnecessary ISO-NE driven cost increases will be lost," industrials said.

Immediate, parallel pursuit of ISO-NE reform and the development of a hybrid alternative is needed to ensure a hybrid approach can be ready by August 1, 2009, when CMP and BHE must give

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PJM Proposes New Bilateral Product for RPM Replacement Capacity

PJM has filed with FERC tariff changes to provide capacity suppliers with additional flexibility to enter into bilateral agreements to secure replacement capacity under the Reliability Pricing Model.

Under current RPM rules, sellers that commit capacity for a Delivery Year have the opportunity in two additional auctions to obtain replacement capacity resources if their originally committed resources are expected for some reason to be incapable of performing in that year. Sellers of committed capacity also may obtain replacement capacity from other suppliers outside the RPM auctions, in the bilateral market. However, if a supplier that committed capacity obtains replacement capacity in the bilateral market, it is responsible for the performance of the replacement resource during the Delivery Year, including any non-performance charges.

Following RPM's implementation, market participants expressed interest in allowing bilateral transactions in which responsibility for performance of a replacement resource remains with the party selling the replacement resource, rather than the buyer. PJM's proposed tariff amendments implement such a policy through a product termed "Locational UCAP."

Locational UCAP would be defined as unforced capacity sold in a bilateral transaction by a Member with available uncommitted capacity to a Member that previously committed capacity through an RPM Auction and that requires replacement capacity. The definition specifies that the Locational UCAP Seller retains responsibility for performance of the resource providing the capacity.

Locational UCAP may not be sold or purchased prior to the date that the final $EFOR_D$ (equivalent

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Aroostook Wind Energy Won't Fund Transmission to Access ISO New England

Recent changes in the wholesale power market have made it uneconomic for Aroostook Wind Energy to invest in transmission infrastructure needed for interconnection and access to the NEPOOL market, the wind developer informed the Maine PUC yesterday (2008-256).

Aroostook Wind Energy is located in the Northern Maine Independent System Administrator market, but would be connected to NEPOOL by the Maine Power Connection, a joint project proposed by Central Maine Power and Maine Public Service (Matters, 12/17/08).

In light of the cost estimates and related data revealed in system impact studies regarding interconnection of the Aroostook project and construction of the Maine Power Connection, Aroostook Wind Energy told CMP and MPS that they should stop work on further system impact studies. While Aroostook Wind said it cannot now sustain any transmission investment it may have been contemplating as part of its project, it told the PUC it would continue its development efforts and intends to obtain land for siting, and conduct environmental studies in the near-term.

CMP and MPS responded by asking the PUC to abate the CPCN case for the Maine Power Connection for 90 days, at which time the utilities will report on their recommended course of action.

CMP and MPS anticipated that much of the line's cost would be socialized, with remaining costs paid by Aroostook and possibly other connected generators. However, the utilities told the PUC they will need to reconsider their proposed approach for interconnection with Northern Maine given Aroostook's decision not to commit to funding any transmission investment.

CMP and MPS also reported they still face "significant" challenges in gaining regional cost support for the project at ISO New England, and in securing a package of benefits to offset costs of having MPS join ISO New England as part of the line's construction.

During the requested 90 day abatement, CMP and MPS will consider alternatives, such as revising the size of the project (either making it smaller, or possibly larger and expanding the line into Canada), pursuing a participant funding approach, and identifying an approach that avoids having MPS join ISO-NE.

Industrials and cooperatives have petitioned the PUC to dismiss the case given the project no longer serves a purpose, citing Aroostook's withdrawal of interest.

ERCOT Zonal Congestion Costs Increase Seven Fold Year-Over-Year

ERCOT is reviewing proposed transmission projects for the next five years totaling $3 billion and expects to improve or add 2,888 circuit miles of transmission and more than 17,000 megavolt ampere (MVA) of autotransformer capacity to the grid, it told the PUCT in an annual electric system constraints and needs report (33577).

The report also analyzes costs to resolve zonal congestion (between the four congestion zones) and intra-zonal congestion. Although zonal congestion costs had been trending downward over the past few years, from $146 million in 2001 to $52 million in 2007, costs in 2008 spiked to $360 million, primarily due to a combination of events, including high fuel costs, revised shadow price caps, and increased wind generation.

Intra-zonal congestion costs are approximately the same as they were in 2007. Local congestion costs decreased from over $405 million in 2003 to $164.4 million in 2007 and $146.8 million through October 2008.

Improvements to the grid completed since 2007 totaled approximately 1,294 circuit miles of transmission and 6,613 MVA of autotransformer capacity with an estimated cost of $1.2 billion.

Along with the five-year transmission report, ERCOT also filed the Long-Term System Assessment which looks at transmission and generation options for the next 10 years (also in docket 33577). The long-term system report is filed with the Texas Legislature in each even-numbered year, as required by Senate Bill 20, and is intended to provide guidance to ERCOT and market participants in evaluating system needs.

According to the long-term assessment,

additional import capacity into Houston is needed. Although an import pathway into Houston from the west, such as from the Fayette to Zenith substations, was generally cost-effective across a range of scenarios included in the study, the specific pathway should be reviewed and selected as part of the ERCOT five-year planning process, ERCOT said.

Load growth in two areas (north of Dallas in Cooke and Grayson Counties and in western Williamson County) may result in the need for long-lead time transmission projects in the next ten years.

Economic benefits from most transmission projects were dependent on the location of new sources of generation, fuel costs, and emissions allowance costs. Given the uncertainty associated with the future development of baseload generation, it is not reasonable to plan large inter-zonal projects at this time, ERCOT said.

Large inter-zonal projects are generally not economic in scenarios that include several new nuclear units. This is due to the fact that the likely locations of new nuclear units are close enough to major load centers that additional inter-zonal projects are not required. An additional connection from Comanche Peak towards the south will likely be economic if two new units are constructed at this location, the report noted.

Large inter-zonal projects are economic if new coal units are built in the general areas considered in the long-term study and gas prices are consistently at the high levels seen earlier in 2008. These projects would be required to transport energy from expected, remote coal plant locations to major load centers, especially Houston, ERCOT said.

Md. PSC Approves Most EmPower Maryland Programs

The Maryland PSC approved the majority of utilities' EmPower Maryland energy efficiency and demand reduction programs, which the PSC said are projected to reduce energy consumption by nearly 5% by 2011 (Cases 9153-9157).

The PSC approved all of BGE's proposed programs, noting that a competitive RFP conducted by BGE to run the programs reduced administrative costs by 35% and outside services costs by 43%, while increasing program incentives by 27% and expanding the programs to allow more ratepayers to participate. BGE's programs, in total, are estimated to reduce peak demand approximately 1,190 MW for 2011, with a 2011 reduction in energy consumption of approximately 1,059,116 MWh.

While the PSC conceded approving some of the programs at the utilities (particularly appliance rebates) was a "leap of faith" given the lack of recent, reliable data regarding the presence and penetration of appliances and other energy efficiency measures in Maryland, the PSC said it was willing to make such a leap because any hope of achieving the EmPower Maryland Act's aggressive consumption and demand reduction goals requires the utilities to start now.

Utilities other than BGE were directed to issue RFPs for the outside services that they will need in order to implement the approved programs, and to file updated cost and cost-effectiveness data with the Commission before proceeding further with implementation.

The PSC dismissed objections to BGE's non-residential efficiency programs raised by the Maryland Energy Group. MEG argued BGE had not complied with the statutory language of the Act requiring that the Commission only approve those programs that are cost-effective for each affected class, since BGE grouped Schedule P and Schedule GL customers together in the Large Commercial, Industrial, and Institutional category. However, the PSC noted the term class was not defined in the Act, and noted that had lawmakers intended the PSC to evaluate the costs and benefits of each program on each rate class, lawmakers could have been prescriptive in using such specific language.

The energy efficiency savings and demand reductions are to be bid into the appropriate PJM markets, including RPM, once rules permitting their participation are developed. Although the PSC will address the mechanics and details of cost recovery at a future date, the Commission said it expects the proceeds from bidding any energy efficiency resources generated by the programs into PJM's capacity auctions to offset the costs of the programs to ratepayers.

The Commission declined to implement a

centralized Home Performance with Energy Star program under the control of the Maryland Energy Administration. The utilities are better equipped to administer and implement the programs than MEA at this point, and better able to move more quickly than MEA to get the programs running, the PSC said.

Although Pepco, Delmarva and Allegheny Power referenced their advanced metering and/or smart grid initiatives as part of their EmPower Maryland filings, the PSC noted review of those proposals will be addressed in separate cases. The issue of fuel switching, raised by Washington Gas Light, will be addressed in 2009, the PSC added.

Pepco and Delmarva had both proposed two solar programs under which the utilities would install solar facilities at substations, and would assist customers with solar installations, including offering low-interest financing. The PSC rejected the programs as they were not cost effective (Matters, 10/17/08).

Briefly:

Reliant Closes Sale of Northeast Books to Hess

Reliant Energy has completed its previously announced sale of its Northeastern electricity marketing assets to Hess Corporation (Matters, 11/17/08). The sale included the books of subsidiaries Reliant Energy Solutions East and Reliant Energy Solutions Northeast, totaling 5.8 million MWh. The 300 customers involved were mostly mid-merit and large C&Is in Maryland, New Jersey, New York, Pennsylvania and the District of Columbia, though some were as small as 25 kW in Maryland. Reliant sold the customers to reduce collateral needs, as part of its strategy to exit the large C&I market.

FERC Accepts ISO-NE Budget

FERC accepted ISO New England's 2009 revenue requirement, denying protests from the Connecticut Attorney General and Office of Consumer Counsel over executive compensation. FERC agreed that ISO-NE's salaries were within a reasonable range of competitive practices for functionally comparable positions among similarly situated entities.

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any potential notice to not renew their Operating Agreements with ISO-NE, IECG said.

IECG claimed remaining part of ISO-NE for the five years from 2008 to 2012 will cost Maine customers approximately $400 million above what Maine consumers should pay.

Industrials objected to the recommended decision's linkage of the ISO-NE energy market and Forward Capacity Market, and argued that Maine's participation in FCM, as opposed to any other method for ensuring resource adequacy, should not be considered as a necessary condition for Maine's continued participation in the ISO-NE energy markets.

IECG further recommended that a collaborative led by the PUC, and not CMP and BHE, should pursue reforms to the Transmission Operating Agreements. Due to the incentives transmission owners receive in building transmission whose costs are socialized across the ISO, "[i]t is not credible to suggest that CMP and BHE can or will abandon their fiduciary obligations to shareholders, and either negotiate a deal adverse to their self-interest or report that they failed and should leave ISO-NE," industrials claimed.

IECG also called the New England States Committee on Electricity a "cruel joke" on consumers, and doubted its participation at the ISO would cure any problems.

But the Independent Energy Producers of Maine, with FPL Energy, countered that the hearing examiners' report understates problems associated with the best hybrid approach.

It's not rational to expect that CMP and BHE will be able to procure services a la carte via negotiations when similar reforms to the Transmission Operating Agreements failed, the IPPs said. Other transmission owners in ISO-NE won't permit Maine's utilities to be "virtual" ISO members in order to avoid transmission construction costs, because such virtual membership would be a "direct threat" to the integrity of ISO New England, the Independent Energy Producers of Maine observed.

Proponents of the a la carte approach have failed to provide any legal support for the assertion that ISO-NE would be compelled to provide a la carte service, the IPPs added. There's no reason to expect that the ISO would agree to such balkanization, the power producers noted.

Bangor Hydro-Electric warned that pursuing development of a hybrid approach simultaneous to pursuing reforms at ISO-NE will likely "marginalize" Maine stakeholders in ongoing ISO-NE reform efforts. A mandate from the PUC to obtain specific reforms could also weaken the negotiation position of CMP and BHE, BHE noted, because counterparties at ISO-NE would know what CMP and BHE must ultimately accept.

The PUC has unclear authority to order changes to the Transmission Operating Agreements, BHE added, and the recommended decision did not address federal pre-emption of authority with respect to BHE.

While FERC return on equity incentives for transmission projects have been criticized in the case, BHE noted the ROEs won't go away simply by leaving ISO-NE, since the ROE adders apply to all new transmission construction, regardless of market structure.

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demand forced outage rate) of a generating unit is established for the Delivery Year, i.e., by the November 30 preceding the Delivery Year. This limitation will ensure that market participants do not oversell their capacity, PJM said. Absent this rule, a generation owner could sell capacity above its unforced capacity value, or more capacity than the resource can provide.

Any capacity sold as Locational UCAP prior to the Third Incremental Auction for a Delivery Year must be confirmed by the buyer prior to the auction as purchased for replacement capacity, or the transaction will be rejected. This measure forecloses a potential opportunity to withhold capacity from the Third Incremental Auction, PJM explained.

A purchaser of Locational UCAP may not offer such capacity into an RPM Auction. This limitation tracks the current rule for replacement capacity obtained through a successful buy bid in an incremental auction: the buyer uses the capacity to satisfy its own obligation, but does not own the capacity and is not responsible for performance of an identifiable unit. Therefore, the buyer has not obtained sufficient rights that would allow it to offer the capacity for sale to third parties in an RPM auction.