Energy Choice Matters
January 13, 2009

Illinois ARES's Subject to RPS, Clean Coal Standard

Illinois alternative retail electric suppliers (ARES's) have been made subject to the state's RPS, as well as a new clean coal portfolio standard, as Gov. Rod Blagojevich signed SB 1987 into law. The Act takes effect June 1, 2009.

The Act makes ARES's subject to subsections (c) and (d) of Section 1-75 of the Illinois Power Agency Act, which established an RPS for default service supply procured for utilities. Under the Illinois Power Agency Act, suppliers must procure 5% of their supply from eligible renewable resources by June 1, 2010, and increasing 1% annually to 10% by June 1, 2015, with subsequent increases of 1.5% annually.

The RPS includes carve-outs for wind and Illinois-based resources, if available. The RPS also includes two cost caps on the procurement mandate, including the use of market price benchmarks, and such that the total amount of renewables to be procured is reduced to limit the total cost increase of bundled electricity per kilowatt-hour (supply, distribution and other charges) to 0.5% in a given year.

RPS obligations extend only to contracts (and associated volumes) executed or extended after the Act, though suppliers will have to document to the ICC any supplies under existing contracts that they seek to exclude from the obligation.

Additionally, the Act requires ARES's to enter "sourcing agreements" with an "initial" clean coal facility developed under the Act for 5% of their load, and possibly other clean coal plants as well. The sourcing agreements are to be cost-of-service based, though they may be PPAs or Contracts for Differences. The clean coal portfolio standard will be subject to cost-based benchmarks, as well as

... Continued Page 5

RESA Branches Out to Retail Gas Market With Four-State Caucus

In an effort to highlight the success of competition, particularly market-reflective pricing, in the retail natural gas industry, the Retail Energy Supply Association launched a gas caucus as a companion to its current advocacy efforts relating to competitive electric markets.

Initially, the gas caucus will monitor and provide regulatory advocacy in New York, Pennsylvania, Illinois and Michigan. In each of those states, except Michigan, RESA is currently active on the electric side. The initial gas states were driven by membership, said RESA President Jay Kooper, and started at four so the Association could manage its growth. Kooper expects RESA to add more states on the gas side this year as it develops its gas advocacy infrastructure. Though ultimate additions will be determined by membership, Kooper noted the Chesapeake region and California will likely draw members' attention.

Participating in the caucus are Direct Energy Services, Hess Corporation, Integrys Energy Services, and U.S. Energy Savings.

Most advocacy efforts will focus on removing remaining barriers to entry and competition, and on refining logistical and operational issues that may hinder competitive supply. The competitive gas market is about 10 years further along than competitive power markets, Kooper noted, and the debate has moved from general questions about market design to narrower questions regarding the efficiency and operation of the market. While issues will differ by market and members will dictate what issues to contest, topics at the forefront of most states include balancing mechanisms and

... Continued Page 6

NYISO Sees Adequate Supplies Through 2018

In a finding which may ease pursuit of backstop reliability solutions at the PSC, the New York ISO announced yesterday that it anticipates sufficient electric power resources (generation, transmission, and demand-side programs) to meet reliability needs for the next ten years (through 2018), as reported in the ISO's Reliability Needs Assessment (RNA).

Previous RNAs had found a supply shortfall looming as soon as 2011, which prompted calls for regulated backstop solutions, such as long-term contracts between LSEs (such as utilities) and generation developers.

Driving the new finding is 1,700 MW of proposed new generation development versus last year, including 800 MW of wind. There have been fewer generation retirements than previously estimated as well. State energy efficiency programs also contributed to the finding, with the NYISO estimating a reduction of approximately 5% of peak load from the previously forecast levels by 2015 based upon currently authorized efficiency funding levels. The ISO's Special Case Resources demand response program has also grown by 761 MW to 2,084 MW since last year.

The 2009 RNA anticipates that New York's peak load will grow to 35,658 MW by 2018, while resources available to serve or offset this load are expected to increase to 42,536 MW.

Of course, results may differ from NYISO's forecast which could cause earlier reliability needs. Such factors include hotter weather and faster load growth, unplanned retirements, failure of power plants to complete retrofits for new smog regulations, and unanticipated impacts from the Regional Greenhouse Gas Initiative.

Alliant, TDUs Offer Settlement on MISO Market Coordination Service

Alliant Energy and the Midwest TDUs proffered a settlement to ease their concerns about the Midwest ISO's proposed Market Coordination Service, which some stakeholders including the TDUs have argued jeopardizes the core of the RTO by allowing transmission owners to access the benefits of MISO LMP markets without joining as transmission owners, and thus escaping regional cost sharing for transmission enhancements (ER08-637, Matters, 11/13/08).

Aside from allowing current non-members to enjoy market benefits without transmission cost sharing, the TDUs are concerned that the proposal would incent current MISO members to leave the ISO, and re-join as Market Coordination Service customers, to avoid their current transmission upgrade cost allocations.

The proposed settlement, signed only by Alliant and the TDUs, "seeks to obtain the upside of MISO market expansion while minimizing the downside risks that inhere in Market Coordination Service as presently formulated."

Under the proposal, Market Coordination Service would be a maximum five-year MISO "trial membership" that is not available to existing MISO transmission owners.

During the trial membership period, participating Market Coordination Service customers would be subject to MISO transmission planning and Regional Expansion Costs and Benefits (RECB) cost allocation for new facilities built by Market Coordination Service customers or MISO transmission owners, except that the net transmission facility costs that could be shifted either to or away from the Market Coordination Service customer via the RECB cost allocation would be limited.

Specifically, during the five-year trial membership, the net payments in either direction (whether the net was payments by the Market Coordination Service customer for facilities built by others or payments to the Market Coordination Service customer for facilities it built) would be capped at one year's Market Coordination Service customer Annual Transmission Revenue Requirement (ATRR).

The trial membership approach, and its cost shifting limitation mechanism, are designed to offer MidAmerican Energy (and Muscatine, Iowa, which is embedded in the MidAmerican area) a way to eventually join MISO with full MISO transmission owner status, TDUs said. One of MidAmerican's chief reasons for not joining MISO fully as a transmission owner is uncertainty as to RECB cost allocation. MidAmerican has been the only transmission owner to express serious and current interest in Market Coordination Service, though the

Western Area Power Administration noted it may be interested in the future.

Several current MISO transmission owners have objected to any limitation on their ability to take Market Coordination Service should they choose to leave MISO.

TDUs reported that Exelon does not oppose the settlement offer.

Integrys Marketer Proposes Mechanism to Ease Logistics of Michigan Choice Cap

Integrys Energy Services proposed a two-step process to determine the amount of load eligible for customer choice in Michigan, to give competitive suppliers certainty regarding the bulk of the load eligible to shop, while still allowing a robust analysis of utilities' weather-adjusted sales figures by Michigan PSC Staff (U-15801, Matters, 11/18/08).

Among several logistical problems with Michigan's 10% choice cap is that suppliers will be signing contracts with customers throughout the year, generally for a future service date. However, the amount of load that is allowed to shop is determined yearly, based on the utility's weather-adjusted retail sales in the preceding calendar year.

If the MWh amount of the cap cannot be known until after the end of the preceding calendar year, a bottleneck of choice supply contracts will be created, Integrys Energy Services noted, with customers and suppliers unsure of whether the contract will be accepted under the cap. Without knowing if such contracts can be implemented, customers will not be able to forecast their energy budgets, and suppliers will not be able to satisfactorily acquire or hedge capacity and energy, the Integrys marketer said.

Integrys Energy Services thus proposed a two-step process to determine the cap, to give suppliers some level of certainty. The first step would require the utility to file by December 15 an 11-month, weather-adjusted retail sales number for the months of January through November. This number would function as the initial, partial cap in MWh. It would not be subject to contest by various parties, but rather quickly verified for reasonability by the Staff. While the weather adjustments could still be contested later, it is virtually impossible that any downward revisions to weather adjustments for January-November would total more than the retail sales for December, Integrys Energy Services noted. Thus, on December 15 of each year, customers and suppliers would know for sure that at least the MWh reported in the partial cap would be available for electric choice for the following calendar year.

The second step would require the utility to file by January 15 the complete, weather-adjusted retail sales number for the preceding calendar year, January through December. This number would be subject to comments, scrutiny by Staff, and approved by the Commission if disputed.

The two-step process allows certainty on 90% or so of the cap, and allows smooth operation for that 90% of choice load, Integrys Energy Services said. The proposal still preserves the use of calendar-year data while giving an opportunity for PSC review.

Integrys Energy Services further suggested that a customer's most recent 12 months of actual energy use in MWh at the time a contract with a supplier is signed (the Contract Date) should be counted toward the cap. For new or expanded facilities and/or customers with less that 12 months of history, the customer would be required to attest to its estimated annual use in a letter to the Commission, and the supplier would be required to attest that it agrees with that estimate and is prepared to serve that amount of energy.

Twelve-month estimates are common in the industry and, in aggregate, would be expected to have a *de minimis* difference from actual usage. For new facilities, both the customer and supplier have a vested interest in formulating an accurate estimate, because it minimizes price and supply risk for both, the Integrys marketer noted. "Commission Staff has no need to vet estimates, because it either has history or has attestations of both the customer and the [supplier] for estimates on new/expanded facilities," Integrys Energy Services said.

The marketer also recommended that an electronic transaction sent to the utility be used to determine whether or not there is room under the cap for a customer. The date and time of the electronic request would determine the priority for the supplier under the first-come, first-served cap.

Under Integrys Energy Services' proposal, the utility must respond to the supplier with acceptance or rejection of the request no later than the next business day after the request. If the utility does not respond to the supplier with an answer by the specified time, then the customer would be deemed to have been accepted, in order to prevent a delay by the utility from creating financial risk for a supplier or customer, Integrys Energy Services said.

If the request is accepted, the supplier would have to submit an enrollment the next business day. Approved requests which are not followed by enrollment would be rejected to prevent speculative requests from suppliers, Integrys Energy Services explained. Rejected requests would remain in the queue and maintain priority to be served upon room becoming available under the cap.

MISO Says Aquila Exit Fee a Condition of its Withdrawal

Allowing a Transmission Owner to withdraw from the Midwest ISO Transmission Owner Agreement (TOA) in any circumstance (including adverse state regulatory action) without first being required to honor all outstanding financial and other obligations to MISO would have "serious negative consequences," MISO said in opposing Aquila's contention that paying an exit fee is not a condition precedent to Aquila's withdrawal from the TOA.

Aquila's financial obligations pursuant to the TOA could exceed $11 million, MISO told FERC (ER09-414). Aquila is seeking to leave MISO after the Missouri PSC denied its application to transfer functional control of its assets to MISO, as the PSC favored Aquila joining SPP.

Though Aquila has never transferred functional control of its transmission system to MISO, it has been a MISO member since 2001, and transferred reliability coordination responsibilities to MISO. However, Aquila is not a participant in the MISO energy markets and it receives most of its OATT administrative services under arrangements with the Southwest Power Pool. It is seeking to transfer reliability coordination responsibilities to SPP as well.

As part of a settlement with MISO in 2002 and amended in 2003, Aquila received discounted MISO rates under Schedule 10-B, which were to continue until Aquila secured state regulatory approval for the transfer of functional control of its assets. Aquila was to pursue approval of the control transfer "diligently."

However, MISO argued that Aquila failed to diligently pursue state approval for the transfer of its transmission system, and thus argued Aquila should not have received reduced MISO pricing under the settlement. About $6 million of MISO's proposed exit fee is to recover the difference between full MISO costs and Aquila's discounted Schedule 10-B rate.

MISO noted Aquila delayed the filing of its second Missouri PSC application for the control transfer more than one year after the original settlement, without justification. Once filed, Aquila failed to prosecute the second application, thereby causing the PSC to dismiss it two years after filing, MISO added. According to MISO, Aquila then delayed the filing of the third application for two years after the dismissal of the second application; and, once filed, Aquila failed to diligently prosecute the third application.

The remaining $5 million of the $11 million exit fee is for the reliability coordination services that MISO has been providing.

MISO told FERC that, in recent weeks, the financial community has made it very clear that the Midwest ISO's credit ratings would suffer if withdrawing Transmission Owners are not mandated to meet their exit fee obligations.

The TOA allows members to withdraw upon 30 day's notice due to any state regulatory authority that imposes conditions on MISO participation which adversely affect a signatory. The determination of the adverse impact is the "sole judgment" of the signatories, MISO noted.

Furthermore, members can exercise the provision whether or not the signatory is subject to that regulatory authority's jurisdiction. Thus, for example, any other MISO transmission owner could seek to leave MISO due to the Missouri PSC's decision to deny the transfer of Aquila's assets, by claiming the decision adversely affects their participation as well (by reducing cost sharing, creating seams, etc.).

Thus, unless the protective mechanisms of the TOA are enforced, nothing would prevent a long-term Transmission Owner from leaving the

Midwest ISO by claiming adverse regulatory or governmental action without having to comply with the TOA's "hold harmless" exit fee and other obligations, MISO said.

Briefly:

CAPP Abandons Luminant Deal, Signs with NextEra, Direct

Citing economic uncertainties resulting from the unfolding financial crisis, the Cities Aggregation Power Project has abandoned its plan to sign a 24-year PPA with Luminant to supply members, and instead opted for a five-year supply agreement with NextEra (FPL) Energy, with Direct Energy handling billing and administration, covering more than 100 cities (Matters, 9/19/08). About only 40 CAPP members singed up for the Luminant deal, as many balked at the bonds required to finance the deal, especially in today's climate. A hefty prepayment requirement and the length of the Luminant obligation also led to some resistance by certain civic leaders. The recent decline in retail prices also made a shorter-term deal more competitive. CAPP said the new contract with NextEra and Direct will save more than $30 million compared to prices paid in 2008, with prices ranging from 5-8¢/kWh, plus distribution and administrative charges, depending on location. The Luminant price started at 5.6¢ and would have escalated to 11.4¢ over the life of the contract.

Olde Towne Energy Defaults on MISO Credit Obligations

Olde Towne Energy Associates has defaulted under the Midwest ISO tariff, and MISO is suspending any and all services received by Olde Towne Energy Associates under its Service Agreement, Market Participant Agreement, and the Energy Markets Tariff, effective January 13. The default was caused by Olde Towne Energy's failure to cure a Total Potential Exposure Violation under the credit provisions of MISO's tariff.

Pa. PUC Directs Allegheny to Shorten Lead Time for 12-Month Contracts

West Penn Power (Allegheny) was directed by the Pennsylvania PUC in a recent order to re-file its Tranche Schedule for its default service RFP because the PUC found that West Penn Power incorrectly assigned a lead time greater than six months for Service Type 10, Service Type 20, and Service Type 30 12-month contracts. The Retail Energy Supply Association, Direct Energy Services and Reliant Energy had brought the matter before the PUC in exceptions to a West Penn Power compliance filing, noting that West Penn Power had filed for a 19-month lead time for the 12-month contracts, in contravention of a July order.

Mass. Munis Exploit Ice Storm to Push Agenda

The Massachusetts DPU has formally opened an investigation (09-01) into electric utilities' preparation for and response to the December 12 winter storm which left some customers at Unitil without power for two weeks. Munis have seized upon the company's performance and customer anger to call for laws which would ease municipalization of distribution systems.

Illinois RPS ... *from 1*

the requirement to not raise all-in retail rates more than 0.5% in a year.

Under the Act, the ICC "shall" revoke the certification of any ARES that fails to execute a sourcing agreement with the initial clean coal facility. The sourcing agreements with the initial clean coal facility shall be subject to both approval of the initial clean coal facility and by the General Assembly, and shall be executed within 90 days after any such approval by the General Assembly. The ICC "shall" also revoke certification for failure to meet the RPS.

Utilities, through the IPA procurement, are subject to a clean coal standard as well.

Eligible clean coal facilities must sequester at least 50% of carbon dioxide emissions, and limit emissions of other pollutants such as sulfur dioxide. Plants coming online after 2015 must sequester more than 50% of carbon dioxide emissions.

The law mainly benefits Tenaska and its Taylorville Energy Center clean coal plant, which is in line to become the initial clean coal facility, subject to General Assembly approval. Tenaska projects the plant's cost at $2.5 billion, with completion expected in 2014.

RESA ... *from 1*

penalties, nomination rights, cash-out procedures, storage assignment, capacity release, marketer financial/credit standards, purchase of receivables, and customer contracting/disclosure requirements.

Kooper pointed to the success in bringing market-reflective pricing, with monthly price changes typical, to mass market retail gas customers. While acknowledging the difference between electricity and gas, Kooper noted customers have become "comfortable" with monthly pricing in the gas market, and know how to handle price changes, belying arguments that small electric customers cannot handle market-reflective pricing.

Calling expansion into gas markets a "natural evolution" for RESA, the new caucus is also meant to attract new members to the Association which has grown considerably since 2006 and now stands at 11 members (after Direct acquired fellow member Strategic).

RESA has previously intervened in occasional gas proceedings, particularly in New York, but the caucus represents the first concreted effort to focus on the retail gas market.