Energy Choice Matters
September 17, 2010

Green Mountain Energy to Have Access to NRG Renewable Supply Despite Stand Alone Status

Although Green Mountain Energy will continue to operate as a stand-alone business within NRG Energy, NRG plans to "align" its renewable portfolio with Green Mountain's retail business in order to offer new products and enhanced services.

As reported yesterday, NRG has agreed to acquire Green Mountain for $350 million (Matters, 9/16/10). As of the end of 2009, Green Mountain served more than 300,000 customers, primarily in Texas.

Green Mountain said that it will have access to NRG's renewable generation sources to use for its business. Much of the success of NRG's Reliant Energy acquisition has been due to incorporating Reliant's retail load obligations into NRG's generation and wholesale power marketing book. Additionally, Reliant's access to this generation significantly decreases collateral costs that would otherwise need to be posted with third party wholesale suppliers.

Although Green Mountain's immediate focus is on its existing ERCOT business and ramping up its relatively new New York book (entering the market last year), NRG Energy CEO David Crane said in a letter sent to regulators, legislators, and other community partners that NRG will also, "work to extend Green Mountain's tremendously well received product to new markets."

"[W]e expect to extend Green Mountain's industry leading brand across our core operating regions, providing additional competitive choice - and a pure green energy option - to both residential and commercial customers..." Crane said in the letter.

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N.Y. PSC Adopts Gas, Electric Rate Plans for NYSEG/RG&E

The New York PSC adopted rate plans extending for three years and four months governing both electric and natural gas service at NYSEG and Rochester Gas and Electric. The rate plans are substantially based on a joint proposal, but the PSC did not issue a written order on the rate plans yesterday (09-E-0715 et. al.)

As only noted in *Matters*, the joint proposal would add commodity-related credit and collections costs, and a portion of call center costs, to the POR discount rate (Only in Matters, 7/15/10). Under the joint proposal, the POR discount percentage is to be comprised of the following components: commodity-related uncollectible costs, a financial risk adder, and commodity-related credit and collections and call center costs. All retail access customers, even those on utility consolidated billing, currently avoid commodity-related credit and collections costs, and a portion of call center costs (Only in Matters, 2/16/10).

The POR financial risk adder for each utility, regardless of commodity, is to be set at 20% of the applicable uncollectible percentage.

The joint proposal also includes a stipulation entered into among the utilities and several retail gas supply parties. Among other things, this gas supply stipulation provides that as of the beginning of the new rate year, the utilities would change the due date for a daily-metered customer's request

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Briefly:

Duke Energy Retail Sales Seeks Pennsylvania Electric License

Duke Energy Retail Sales, LLC has applied for a Pennsylvania electric generation supplier license to serve commercial customers over 25 kW, industrial customers, and governmental customers in all service areas. Duke Energy Retail Sales stated that it may also offer demand response services and renewable offerings at a later date. In discussing August earnings, executives at parent Duke Energy Corp. said that Duke Energy Retail Sales may expand its supply relationships with Ohio-based customers to include their out-of-state operations. Aside from serving these multi-state accounts, executives said during the August earnings call that Duke Energy Retail Sales does not currently expect to broadly participate in markets outside of Ohio (Only in Matters, 8/4/10).

Gexa Energy Apparently Seeking Authority to Serve Maryland Residential Customers

Gexa Energy has submitted to the Maryland PSC an amendment to its electric supplier license which is described in the PSC's official filings system as a "request to serve residential customer class" [sic]. A copy of the filing was not available, and Gexa said that it was not prepared to discuss the filing at this time. Separately, Gexa also confirmed that it will maintain the Gexa brand name for its mass market Texas business while it undergoes a rebranding in other markets (see Matters, 9/3/10). For its Northeast and Midwest retail supply business which to date has only served commercial and industrial customers (aside from opt-out aggregation in Ohio), Gexa is adopting the name NextEra Energy Services, and confirmed that the name will be applied in each state aside from Texas.

Spark Energy Receives Conn. Electric License, Readies Market Entry

The Connecticut DPUC granted Spark Energy, L.P. an electric supplier license to serve residential and commercial customers. Spark is moving expeditiously to enter the Connecticut market, having already submitted affidavits of EDI capability with both utilities, and pricing and disclosure labels for its offers.

PUCT Staff Seeks to Revoke REP Certificate of Telecom Consulting and Services

PUCT Staff have filed a petition (38683) to revoke the REP certificate of Telecom Consulting and Services, LLC, alleging that Telecom Consulting and Services has failed to meet the new financial requirements of Subst. R. 25.107(f). Separately, Staff's petitions to revoke the REP certificates of Lahey & Partners, LLC (38680), GTC Energy, Inc. (38681), and Lehman Power Services, LLC (38682) were made public yesterday and, as expected, each is based on alleged non-compliance with the new requirements of Subst. R. 25.107

Md. PSC Adds Questions to RPM Investigation

The Maryland PSC has sought comments on two additional questions relating to its investigation of PJM's Reliability Pricing Model (PC22, see Matters, 8/17/10). The questions are:

- Are PJM's proposals to place limitations on Demand Response within the Reliability Pricing Model reasonable?
- What are the implications to Maryland's Demand Response programs if such limitations are adopted?

CenterPoint Tool Allows Customers to Determine Schedule for Smart Meter Installation

CenterPoint Energy has launched an online tool to allow REPs and customers to find out when a customer's smart meter will be installed (www.CenterPointEnergy.com/smartmeterschedule). The tool presents consumers with a three-month range during which they should expect to receive a meter, as well as the opportunity to register for e-mails on energy efficiency and smart meter benefits.

FERC Lifts Price Cap for Electric Transmission Capacity Reassignments

FERC has permanently lifted the price cap for all reassignments of firm transmission capacity by wholesale electric transmission customers (RM10-22). A written order was not published yesterday.

FERC Modifies Penalty Guidelines
FERC voted to issue modified Penalty Guidelines in Docket PL10-4. FERC has not yet published a written order on the guidelines. The order is to generally affirm the use of the U.S. Sentencing Guidelines as an appropriate model for the penalty guidelines.

FERC Denies Rehearing on Order Which Directs NERC to Overrule Stakeholders
FERC denied rehearing and clarification of its March order (RR09-6-001) which ordered NERC to revamp its process for designing electric reliability rules in order for the Commission to overrule the results of the NERC stakeholder process which had resulted in a rule that FERC found unsatisfactory (see discussion in Matters, 3/19/10).

Rapid Power Management Announces D.C. License
Rapid Power Management announced this week that it has received a D.C. electric broker license. The granting of the license was first reported by *Matters* in August (see Matters, 8/10/10), and Rapid Power Management has since also received a Pennsylvania broker license (Only in Matters, 9/3/10)

N.Y. PSC Adopts Gas Rate Plan for Consolidated Edison

The New York PSC adopted a joint proposal governing a three-year natural gas rate plan at Consolidated Edison, though a final order was not published (09-G-0795).

As only reported in *Matters*, the joint proposal calls for ConEd to implement its proposal to eliminate Daily Delivery Service and Daily Cashout Service for firm transportation customers and to provide Load Following Service to both firm sales and firm transportation customers (Only in Matters, 5/18/10).

Every firm sales and transportation customer is to pay the same rate per therm for Load Following Service. The unitized Load Following Charge may be adjusted in any month based on a change in ConEd's projected annualized cost to provide the service and/or a change in the projected annual volumes for delivery to firm full service and firm transportation customers.

Currently, for firm sales service customers, the costs associated with balancing are included in the Gas Cost Factor. Under the joint proposal, such balancing costs will no longer be included in the Gas Cost Factor, and will instead be billed through the Monthly Rate Adjustment (MRA). ESCO customers will pay the same Load Following Charge as full service customers through the MRA, and ConEd will no longer bill firm transportation customers separately for balancing service since the charges will be included in the MRA.

The joint proposal will continue separate Merchant Function Charges for SC 1, SC 2 Heating, SC 2 Non-Heating, SC 3, and SC 13 customers, with different credit and collection components established for the residential and non-residential classes. Separate Uncollectible Accounts Expense factors will be calculated for each of the three Gas Cost Factor groupings, and will reflect the overall uncollectible rate of 0.79%, with uncollectible rates of 1.06% for residential customers and 0.56% for non-residential customers.

Under the joint proposal, ConEd will continue to include in the Merchant Function Charges applicable to SC 1, SC 2 Heating and Non-Heating, SC 3, and SC 13 customers, and in the MRA applicable to all firm customers including firm transportation customers served under SC 9, charges to recover the working capital costs associated with gas in storage.

Gas storage working capital costs will continue to be split between sales-related and reliability/balancing-related costs. Sales-related costs will continue to be recovered only through the Merchant Function Charge, and reliability/balancing-related costs will continue to be recovered only through the MRA.

The joint proposal will set the billing and payment processing charge at $1.04 for single service gas customers taking sales service from ConEd and for retail access customers receiving dual bills from ConEd and their ESCO. Dual fuel customers will pay no more than $0.52 for the gas billing and payment processing charge.

The monthly Gas Cost Factor for each year in the three-year rate plan will reflect a target Factor of Adjustment Ratio for lost and unaccounted for gas equal to 1.0133.

Under the joint proposal, ConEd will begin providing natural gas customer load profile data directly to the customer, or customer's representative. Currently, load profile data is only available to ESCOs, and includes 12 months of projected weather normalized delivery quantities derived from the customer's actual or estimated historical gas consumption.

Additional details regarding terms of the joint proposal can be found in our 5/18/10 story.

Md. PSC Waives Consolidated Billing, Electronic Transaction Mandate at Chesapeake Utilities

The Maryland PSC has granted Chesapeake Utilities Corporation a waiver of the requirement to offer consolidated billing (pursuant to COMAR 20.59.05) and a waiver of the requirement to develop an electronic transaction system (pursuant to COMAR 20.59.01.03), citing concerns regarding cost recovery for such new systems given the limited amount of customers eligible for retail choice on Chesapeake's system.

Chesapeake had not sought the waivers, but had applied to institute a "Supplier Cost Recovery" charge, which would only be imposed on competitive supply customers, to recover various costs of COMAR 20.59 implementation such as the costs of an electronic transaction system. Additionally, Chesapeake filed to impose an $8 per customer fee per month to issue a utility consolidated bill (Only in Matters, 10/9/09).

Only large commercial and industrial customers whose annual usage is equal to or greater than 30,000 Ccf are allowed to purchase gas from third-party suppliers in Chesapeake's service area.

"The Commission is concerned that the costs associated with implementation of these two COMAR provisions may result in significant costs to the Company without a means to recover the costs in a timely manner in light of the small number of customers that currently are able to shop for their natural gas supply. Although the Company did not request a waiver from these provisions, the Commission finds that such a waiver is appropriate for at least some period of time," the PSC said.

Since the Commission granted a waiver of the utility consolidated billing requirement, the Commission said that it need not approve Chesapeake's proposed Purchase of Receivables program, which had included a proposed discount rate of 1%.

Additionally, due to the waivers, the PSC rejected the $8.00 consolidated billing charge and the proposed surcharge to recover the costs of implementing an electronic transactions system.

"In the event circumstances should change in any material respect, such as the Company changing its practice so as to allow all customers to shop for natural gas supply, or competitive gas suppliers demonstrating that they would serve the firm large C&I customers, but for the lack of consolidated billing and the electronic transactions system, the Company should notify the Commission and either: (1) file a renewed request for a waiver; or (2) make a compliance filing pursuant to the then current provisions of COMAR 20.59," the PSC ordered.

Pa. PUC Approves Peoples' Proposed Retainage Rates

The Pennsylvania PUC ultimately accepted levels for retainage rates at Peoples Natural Gas as proposed by the Office of Trial Staff and the company, but modified several findings regarding Lost and Unaccounted for Gas (LUFG) as contained in a recommended decision to ensure that the PUC's decision in the instant §1307(f) proceeding does not prejudge the reasonableness of future LUFG levels (R-2010-2155608).

The Commission accepted increasing the retainage rate for GS-T customers (small transportation) to 7.8% from 7.3%, and increasing the retainage rate for Rate T customers (large transportation) to 5.6% from 5.2% (Only in Matters, 7/22/10). "[T]he record in this proceeding does not include sufficient information to make a specific determination regarding the reasonableness of peoples' LUFG or to make an adjustment to the LUFG component of OTS's proposed retainage rates at this time," the Commission said in accepting the proposed rates.

Dominion Retail had protested the retainage rates, and the Office of Small Business Advocate had sought a cap on LUFG, arguing that the proposed LUFG levels, which have increased sharply, have not been justified (see Matters, 6/25/10).

The PUC, however, found that the record did not provide sufficient information to develop a specific threshold where Peoples' LUFG becomes unreasonable for ratemaking purposes. "Therefore, *at this time*, we will not adopt a cap on LUFG such as the one proposed by the OSBA in this proceeding," the PUC said [emphasis by PUC].

"However, we want to make a clear distinction between the reasonableness of Peoples' LUFG rate based on the record in this proceeding and the standard for reasonableness to be developed in future proceedings where Peoples LUFG rates will be addressed. Our decision not to adopt the OSBA's proposed cap should not be interpreted as a determination that the 6.66% 2007-2009 three-year average LUFG rate is a standard for reasonableness in the future," the Commission stressed in its order.

Furthermore, the PUC rejected a specific finding of the ALJ which does not affect the overall LUFG rate level but does preserve the Commission's ability to adjust the level in the future. The ALJ had concluded that since Peoples is complying with Commission orders to mitigate its LUFG levels, it should form the basis of a finding that Peoples is taking reasonable steps to mitigate its LUFG levels, and therefore, that its LUFG levels are reasonable.

"However, we concur with the OSBA that the reasonableness of a mitigation measure depends on whether the measure was successful in reducing LUFG, not whether such measures were carried out. Consequently, we reserve any findings on the reasonableness of Peoples' LUFG mitigation measure until the costs and benefits of those measures are adequately addressed on the record of future proceedings," the PUC ordered.

Although Peoples is currently subject to several directives to analyze and report on LUFG levels, the PUC found that, "we need to accelerate and enhance our review of Peoples LUFG."

The Commission directed Peoples to file information in the next 1307(f) proceeding so that a record may be developed to make a determination on a just and reasonable LUFG rate.

Furthermore, the PUC directed Peoples to develop and submit, as part of its next 1307(f) filing, specific mitigation measures and LUFG targets for its: (1) gathering system, (2) storage system and (3) transmission and distribution system for the February 1, 2011 to September 30, 2012 projected period and two subsequent years following the projected period. Peoples shall also file the information that was used to develop its measures and targets, such as the engineering analysis and the cost and benefit data (actual and projected).

"Our primary objectives in establishing these filing requirements are to ensure: (1) that Peoples has developed an appropriate plan to reduce LUFG; (2) that the record is developed in subsequent 1307(f) proceedings to determine the extent to which Peoples' LUFG levels are just and reasonable; and (3) that the record contains sufficient information to make an adjustment to Peoples' rates, if warranted," the PUC said.

A settlement in the instant case approved by the PUC also requires that in advance of the 2011 1307(f) filing, Peoples will analyze the potential impacts of assessing a gathering system retainage charge. Peoples is unique among Pennsylvania LDCs in that it has 855 miles of gathering lines on its system.

In a statement, Commissioner Robert Powelson said that but for the fact that Peoples is under new management, "I would vote to deny Peoples recovery of its increase in lost and unaccounted-for gas."

"While Peoples' litigation position on this issue could best be characterized as weak, I am ultimately persuaded by my confidence that the new CEO, Morgan O'Brien, and his team can and will make progress in turning around what has been a negative trend in this area. The Company should be aware, however, that I will not continue to be patient if improvements are not made," Powelson said.

Vice Chairman Tyrone Christy, however, stressed that any increased LUFG that results from Peoples' unique level of gathering lines must be considered in light of the "substantial benefits" which accrue to customers from locally produced gas which Christy said lowers purchased gas costs and reduces interstate transportation capacity requirements.

The §1307(f) settlement adopted by the PUC also provides the following with respect to cash-outs at Peoples:

1. Peoples will increase the imbalance trading to 4 days;

2. Peoples will provide estimates to each NP-1 supplier about anticipated cash out pricing and the supplier's imbalance level for each given month prior to the imbalance trading period;

3. Peoples will post imbalance levels to its bulletin board if requested by the NP-1 supplier/customer;

4. Peoples will accept suggestions from other suppliers on managing imbalances and consider implementing other administrative changes that may be helpful; and

5. Peoples will modify its current transportation balancing provisions of its tariffs for P-1 and NP-1 customers to provide for a maximum 20% multiplier.

Connecticut DPUC to Develop RFP for Repowered Resources in Case Future Need Arises

Although a final decision from the Connecticut DPUC on the state's integrated resource plan finds that no further action needs to be taken at this time to procure new energy or capacity resources, the Department will, because uncertainties exist, initiate a process to develop a Request for Proposal (RFP) and evaluation methodology for repowering and other resources so the Department is ready to act quickly should the need for a procurement occur (10-02-07).

"The Department believes that under the most likely scenarios, no further capacity resources will be required in Connecticut over the near term; however, the Department also recognizes that the assumptions underlying these scenarios can change rapidly and there are some scenarios where Connecticut could end up capacity constrained over the near-term or in which other economic and environmental opportunities beneficial to ratepayers present themselves. Therefore, establishing a process now to craft an RFP and have it ready to execute when necessary will provide the Department with a much more organized and fruitful end result when a resource need or benefit does appear," the final order states.

"Additionally, the Department cannot ignore the possibility raised by the CEAB [Connecticut Energy Advisory Board] that the repowering of resources, or other actions, can potentially provide substantial economic or environmental benefits to Connecticut ratepayers. The Department believes it is important to note that legislation passed the House and Senate this past session, Public Act No. 10-97, but was vetoed by Governor Rell on May 24, 2010. That legislation, among other things, would have required the IRP developed in 2010 to indentify [sic] options to reduce the price of electricity by at least fifteen percent. Though the parties noted in this Docket that a 15% rate reduction was almost assuredly unachievable, the Department cannot ignore that the resource decisions made now and in the future effect current and future rates. The Department encourages the parties to include in their filings an RFP proposal and RFP process that could lead to bids that significantly reduce current rates. Such a bid result would most certainly be found to be one of the best bids," the Department said.

The DPUC reiterated that any procurement process for resources that aren't required for resource adequacy should be mindful of the criteria for such procurements set forth in Docket No. 08-07-01, which, among other things, evaluates whether a proposed project requires ratepayer funding in order to be built, and whether the project is likely to reduce rates.

The DPUC also concluded that there will be adequate renewable supplies until 2013, but the Department is concerned that tight credit markets and the current economic downturn have placed constraints on the types of renewable projects that can obtain financing. "The CEAB testified that virtually all recent renewable projects are being financed and developed via a long-term contract with an EDC or through a bilateral contract between private entities ... The CCEF [Connecticut Clean Energy Fund] also stated that renewable projects are unlikely to be developed without long-term contracts that provide a sufficient revenue stream to attract financing," the DPUC noted.

"The mandates of the 2020 RPS, coupled with the current challenges for renewable projects in obtaining financing, as well as concerns about the development of in-state renewables, suggest that the Department may need to consider renewable resource procurements to assure an adequate and affordable regional supply of Class I resources and as a means to fulfill the policy objective to develop in-state energy," the DPUC said.

The DPUC said that the CEAB should consider changes to the RPS eligible technologies, such as the inclusion of large scale hydro, modifications to the annual renewable requirements, and other options that might be more cost effective to meet the RPS objectives. Among the policy alternatives that the CEAB shall consider are (1) an increase in the annual Class I RPS requirement from 7% in 2010 to a percentage lower than 20% in 2020, and (2) a commensurate increase in the annual Class III RPS requirement from 4% in 2010 to a higher percentage in 2020. Increasing the Class III requirement is one policy option that could alleviate the current Class III oversupply, provide greater incentives for independent energy efficiency projects and meet environmental goals at a lower cost than Class I resources, the DPUC said.

Pa. PUC Adopts Solar Policy Statement

The Pennsylvania PUC adopted a final solar policy statement intended to provide longer term revenue stability likely needed to support both small-scale and large-scale solar development, and intended to address other barriers that could prevent development of new solar projects (M-2009-2140263).

The policy statement is only applicable to electric distribution companies (EDCs). The Commission declined the recommendation of Duquesne Light to extend the applicability of the policy statement to electric generation suppliers, since the Commission does not have ratemaking and rate recovery authority over electric generation suppliers (EGSs). "With that said, we strongly encourage EGSs to utilize, where applicable, the standards developed as a result of this policy statement," the PUC said in its order.

The policy statement encourages EDCs to procure solar renewable energy credits (SRECs) derived from large-scale solar projects though RFPs. For small scale solar projects, EDCs are encouraged to procure SRECs through both competitively bid RFPs and bilateral contracts.

EDCs may enter into bilateral contracts for SRECs from small solar projects subject to the following conditions, among others:

(i) The price negotiated for SRECs should not exceed the Commission-approved average winning bid price in the EDC's most recent RFP for large-scale solar projects.

(ii) When an EDC has not utilized an RFP for a large-scale project, the price negotiated for SRECs should not exceed the Commission-approved average winning bid price from the most recent large-scale solar RFP by another EDC in the Commonwealth

The final policy statement strikes language from a draft which held that the amount of small-scale solar project SRECs procured through bilateral contracts during a single compliance year should not exceed the number of SRECs procured by the EDC in its last large-scale solar project procurement. The Commission struck this requirement after determining that the market price for SRECs from small-scale projects should dictate the limit to be obtained from these sources.

The policy statement states that EDCs should employ standardized contracts for their purchase of SRECs from large-scale solar projects and small-scale solar projects, and encourages EDCs to execute a master agreement with a solar aggregator for the purchase of SRECs from various sources that establishes a prevailing SREC market price at a particular point in time through letter agreements that incorporate the terms of the master agreement.

The Commission declined to adopt a policy statement that promotes a multi-EDC or statewide purchase of SRECs as suggested by the FirstEnergy companies and Office of Small Business Advocate.

"The Commission does not believe that a single statewide or multi-EDC solicitation for SRECs is authorized by the Public Utility Code. In addition, the Commission does not believe that such a method would provide the best results for EDCs, EGSs or their customers," the PUC's order states.

Commissioners Robert Powelson and John Coleman, Jr. offered a joint statement, "expressing our strong concerns with any legislative attempts to increase the current Alternative Energy Portfolio Standards Act ('AEPS') requirements."

"In our view, it is critically important that we not change the legislative provisions in order to promote one renewable source over another. We also want to stress that additional AEPS mandates on the solar front warrant open and honest debate on compliance costs as well as the impact on ratepayers going forward. We are deeply concerned with forcing consumers to pay for additional solar energy at a cost that is three to four times higher than other generation sources," Powelson and Coleman said.

"We also firmly believe that solar renewable energy credits ('SRECs') should not be based on an artificially established floor price. The SREC market should be permitted to develop, unencumbered. Moreover, we strongly believe that agreements to purchase SRECs should not be mandated to have terms beyond 10 to 15 years in length," Powelson and Coleman added.

Powelson and Coleman further said that EDCs should be provided additional flexibility to manage SRECs through: 1) the extension of bank-life of purchased SRECs to five years beyond their vintage; and 2) prior to the expirations, any unused SRECs may be monetized, with any loss or gain on the sale to be borne by/shared with customers.

FERC Denies Rehearing on Tres Amigas

FERC denied rehearing of its two orders relating to the Tres Amigas project, which is seeking to establish an HVDC project linking ERCOT, the Western Interconnect, and Eastern Interconnect.

Several Texas industrial customers have opposed the project due to its potential to export low cost power out of ERCOT, particularly wind power which customers within ERCOT are essentially subsidizing through the Competitive Renewable Energy Zone build-out, and due to the potential to subject ERCOT to federal interference due to the project placing ERCOT within interstate commerce.

In Docket EL10-22, FERC denied rehearing sought by several industrial customers related to a disclaimer of FERC jurisdiction sought by Tres Amigas which was denied by FERC (see Matters, 3/19/10). The industrials argued that in FERC's original order denying the disclaimer, the Commission made an impermissible finding in a footnote that the transmission and distribution successors of the electric utilities in ERCOT that were previously ordered to interconnect and wheel power from the FERC-jurisdictional interstate transmission system under sections 210 and 211 of the Federal Power Act remain subject to the Commission's jurisdiction to issue new interconnection orders under section 210.

FERC's original March 2010 order had noted that sections 210 and 211 of the Federal Power Act allow certain interstate interconnections to be made without otherwise subjecting the electric utility or other entity applying under those sections to FERC jurisdiction for any purposes other than the purposes specified in sections 210 and 211. Essentially, FERC was suggesting an alternative mechanism under which Tres Amigas may seek a disclaimer of FERC jurisdiction.

In a rehearing request, Occidental Power Marketing noted that, according to Texas law, the ERCOT transmission and distribution utilities cannot sell electric energy, yet section 210 only applies to the transmitting facilities of an "electric utility," and an electric utility must, by definition under the Federal Power Act, sell electric energy.

FERC denied rehearing on this matter stating that it made no findings in its original March order under either section 210 or 211 of the FPA because no application under section 210 or 211 of the FPA was before it. Furthermore, the Commission said it had expressly declined to make prospective findings under any potential application under section 210 and 211, and said that it will not prejudge the issue raised by industrials on rehearing.

In Docket ER10-396, FERC denied rehearing sought by Occidental Power Marketing regarding FERC's granting of negotiated rate authority to Tres Amigas.

Sack Distributors Says Conn. Disclosures Not Possible for Aggregators

Several disclosures proposed to be required of Connecticut electric aggregators are unworkable as the aggregator will not know the information when soliciting customers, Connecticut aggregator Sack Distributors Corp. said in comments on the DPUC's proposed marketing standards (10-06-2).

The standards, which in most cases would apply to all customer classes, were first reported in *Matters* (9/6/10 with full analysis in 9/8/10).

Sack Distributors said that when acting as a "true" aggregator, the aggregator will not have specific information on electric rates, since the customer pool will first be assembled before negotiating for supply, and thus the aggregator will be unable to comply with proposed disclosure of rates during solicitations. For the same reason, Sack Distributors said that aggregators would not be able to disclose potential termination fees when soliciting customers.

Sack Distributors opposed the requirement contained in the proposal that suppliers and aggregators disclose the distribution company's charges. However, this requirement already exists in statute, for electric suppliers only, under Sec. 16-245o of the General Statutes of Connecticut, which states that when advertising or disclosing the price for electricity, the electric supplier shall also disclose, "the electric distribution company's average current charges, including the competitive transition assessment and the systems benefits charge, for that customer class," which is essentially repeated verbatim in the draft standards.

Sack Distributors also argued that many of the standards should only apply to the residential market, particularly any standards applicable to door to door sales.

Green Mountain ... from 1

As only noted in *Matters*, Crane said earlier this week, prior to the Green Mountain announcement, that renewable retail electric sales in the U.S. could "easily" grow by a factor of 10 to 45 TWh, or 3% of total load in competitive retail markets, by 2020 (Only in Matters, 9/15/10). Crane said that renewable retail electric sales in competitive retail markets were 4 TWh in 2008, or less than 1% of sales in these deregulated retail markets.

Green Mountain CEO Paul Thomas will remain Green Mountain's leader and will report to Crane. Crane said that Green Mountain will continue to be run by present management, with only "modest" changes to its organizational structure, taking into account that Green Mountain will be owned by a public company. Green Mountain will maintain its headquarters in Austin, Texas.

NYSEG/RG&E ... from 1

to change gas supply from one provider to another from five business days prior to the end of the month to the fifteenth calendar day of the month. The switch day will remain on the first calendar day of the next month.

NYSEG is to consolidate Gas Supply Area 1 (GSA 1) and GSA 3, and is to establish a Gas Reliability Surcharge for the consolidated GSA at the beginning of the rate year. The utilities are to also establish a collaborative to address any impacts of the GSA consolidation on mandatory capacity release assignment program pricing and the derivation of the gas reliability surcharge, and to also examine the costs and ramifications of -- and methodology for -- releasing capacity to ESCOs at the system weighted average cost of capacity, among other issues.

Starting April 1, 2011, ESCOs serving RG&E delivery customers are to be required to provide capacity to meet 100% of their non-daily metered customers' load based on an average peak day of 66 Heating Degree Days (HDD) of load, instead of the previously-applicable design day requirement based on 75 HDD. On days exceeding 66 HDD, RG&E is to supply the difference between 66 HDD and the HDD of the particular day. RG&E is to implement a Gas Reliability Surcharge to recover the costs associated with retaining pipeline capacity to meet demand on behalf of ESCO non-daily metered customers at times between 66 and 75 HDD. The surcharge is to apply to customers taking service from ESCOs under gas SCs 5, 7a, and 9. RG&E is to include the surcharge in the Small Transportation Service Rate Adjustment Statement. Surcharge revenues are to be credited to the Gas Supply Charge.

Further discussion of these terms of the joint proposal, and additional items, are in our 7/15/10 story.