Energy Choice Matters

May 14, 2010

PSNH Says Energy Service Costs Exceeded Revenue by $46 Million in 2009

Public Service Company of New Hampshire has sought approval from the New Hampshire PUC to reconcile a net under-recovery of Energy Service (ES) costs of $4.4 million for the year 2009 (DE 10-121).

For the year 2009, Energy Service costs exceeded Energy Service revenues by $45.9 million; however, PSNH entered the year with a $41.5 million over-recovery that accrued in 2008, producing the net $4.4 million under-recovery.

The $4.4 million net under-recovery was primarily due to increased migration to competitive supply from the level assumed in the Energy Service rate update that took effect on August 1, 2009, PSNH said.

The average cost of Energy Service for 2009 was 10.30 cents per kWh, while the Energy Service retail rate was initially 9.92 cents per kWh through the end of July, then lowered to 9.03 cents per kWh effective August 1 through the end of 2009. Effective January 1, 2010, the Energy Service rate was revised to 8.96 cents per kWh.

Energy Service costs include the fuel costs associated with PSNH's generation as well as costs and revenues from energy and capacity purchases and sales, the New Hampshire Renewable Portfolio Standard, Regional Greenhouse Gas Initiative costs, and power from long-term Independent Power Producer contracts (IPP) valued at market prices. In addition, Energy Service

Continued P. 4

Retail Suppliers Caution FERC on Compensation for Demand Response

Several competitive load serving entities have raised concerns with FERC's intent to mandate that all jurisdictional organized markets pay demand response the full Locational Marginal Price, warning of potential "collateral impacts," and criticizing the Commission for its apparent haste to, "pick a winner based on anecdotal evidence," rather than a vetted evidentiary record (RM10-17).

Hess Corporation, for example, agreed that current electricity markets do not experience economic demand price responsiveness to any reasonable extent. A fundamental reason for such lack of response, Hess observed, is that most customers do not see real-time prices, while those that do are often characterized by a high value-of-lost-load (VOLL) that serves as a economic dis-incentive to active participation. "Therefore lack of such response is not due to a flaw in the wholesale market itself as FERC's NOPR position might suggest," Hess said.

While FERC's preferred method of paying the full LMP can provide opportunities for price responsive demand at wholesale, "it is not a perfect substitute for natural retail price response, and will cause collateral impacts in the market," Hess cautioned.

"As an LSE in the wholesale market, Hess is dependent on an effective market, and is concerned as to the degree to which such collateral impacts might degrade the efficiency and competitiveness of the market." Moving forward without giving adequate consideration to these collateral impacts, "could have long lasting detrimental impacts on the market as a whole, despite any perceived benefits

Continued P. 5

NRG to Acquire Northwind Phoenix District Energy System

NRG Energy has reached an agreement with APS Energy Services to acquire APS Energy Services' wholly owned subsidiary, Northwind Phoenix LLC, which owns and operates a district cooling system providing chilled water to commercial buildings in the Phoenix central business district.

In addition to the local business district, Northwind also maintains and operates Combined Heat and Power plants that provide chilled water, steam, and electricity to portions of Arizona State University campuses in Tempe and Mesa, and in metropolitan Tucson, including that city's convention center.

NRG has said that expanding the capability of Reliant Energy to partner with its large commercial customers on energy projects and services such as Combined Heat and Power is a top priority (Only in Matters, 2/24/10). NRG, through its NRG Thermal subsidiary, operates a number of district cooling systems across the U.S., including several in Pennsylvania under PUC jurisdiction.

With the sale, APS Energy Services said that it plans to focus on its core business of energy conservation and renewable energy contracting services.

The transaction is expected to close in June 2010. Terms were not disclosed.

Retail Suppliers Note Growth in Calif. Local Resource Adequacy Requirements

The current approach to local Resource Adequacy in California is not producing reduced local capacity requirements over time, the Alliance for Retail Energy Markets said in comments on the California ISO's 2011 Local Capacity Technical Analysis, Final Report and Study Results (R.09-10-032).

AReM noted that 2011 will mark the fifth compliance year for Local Capacity Requirements (LCRs), which were established to ensure Resource Adequacy (RA) in transmission-constrained Local Capacity Areas (LCAs).

Since 2006, Local Capacity Requirements have grown from 23,420 MW to 28,058 MW, an increase of 20%, while the LCR deficiency has increased 150% from 385 MW to 964 MW. Moreover, the number of deficient areas has more than doubled from three to seven over the same period.

In fact, for 2011, only three LCRs are not deficient, AReM noted -- North Coast/North Bay, LA Basin, and Big Creek/Ventura. "Even accounting for the addition of the LA Basin LCA in the 2008 compliance year, which added 3,700 MW to the LCRs, the trend is, at best, steady state. Further, while California is experiencing a major recession beginning in 2008, the LCRs are still increasing, by 1.2% from 2010 to 2011," AReM said.

"AReM requests that the Commission consider improvements to the annual LCR process in Phase 2 with the objective to reverse this trend and begin to reduce the MWs of LCRs and number of LCAs when cost-effective, therefore, lowering costs for California's consumers."

AReM noted that the use of "operating solutions" by the utilities can reduce the LCRs, but reported that the utilities proposed no new operating solutions for 2011. "Further, utilities own or control the vast majority of the generation in certain LCAs and can, therefore, benefit if higher LCRs are imposed on LSEs for those areas. AReM is concerned that the utilities, being LSEs, PTOs and owners of generation located in constrained areas, may not have adequate incentives to (a) eliminate the transmission constraints by proposing upgrades or (b) devise operating solutions to minimize LCRs." AReM requested that the PUC address this issue in Phase 2 of the proceeding.

AReM also requested that the Commission direct the CAISO to notify LSEs early in the study process regarding the effect on LCRs of any approved transmission project. "Such early warning will ensure an orderly procurement process for Local RA and that LSEs will have adequate time to employ strategies to minimize costs for their customers," AReM said.

AReM cited the addition of the LA Basin LCA in 2008 as the first such "RA procurement surprise," in which LSEs were given little notice of significant increases in procurement requirements under the CAISO analysis. This year, the CAISO has calculated an increased LCR for the LA Basin of more than 850 MW or nearly 9%. "The CAISO's March 10, 2010 slide presentation revealed to the LSEs for the first time that a major 230-kV transmission line would be out of service for 2011, which apparently created most of the increase."

AReM is concerned about the process of reporting such major changes in LCRs, "which leaves LSEs in the dark until faced with significantly increased procurement obligations."

The CAISO's 2011 LCR Report has identified "voltage collapse" as the limiting contingency in several local areas, AReM added, which has apparently created increased LCRs in those areas. "AReM is unaware of any Commission decision that has approved such action. AReM requests that the Commission: (a) require the CAISO to provide support for this criterion; and (b) determine its appropriateness for setting LCRs."

Detroit Edison Proposes Pilot Critical Peak Rate

Detroit Edison has petitioned the Michigan PSC to offer a pilot critical peak pricing generation rate option open to 5,100 customers who have received advanced meters under its SmartCurrents program (U-16276).

The critical peak pricing rate would be made available on a voluntary basis to a maximum of 5,000 residential customers and 100 secondary commercial and industrial customers taking full service from Detroit Edison who have Advanced Metering Infrastructure installed.

Generation rates would be as follows, for both customer classes:

Power Supply Charges:

Critical Peak:	$1.00 per kWh
On-Peak:	$0.12 per kWh
Mid-Peak:	$0.07 per kWh
Off-Peak:	$0.04 per kWh

On-peak hours would be from 3 p.m. to 7 p.m. on non-holiday weekdays. Mid-peak hours would be between 7 a.m. and 3 p.m., and between 7 p.m. and 11 p.m., on non-holiday weekdays. Off-peak hours would be between 11 p.m. and 7 a.m. on non-holiday weekdays and all hours on weekends and holidays.

When occurring, critical peak hours would fully replace the on-peak hours for that critical peak day, lasting the full period from 3 p.m. to 7 p.m. Detroit Edison expects to implement critical peak pricing for no more than 80 hours per year, for evaluation of the tariff based on several factors including but not limited to economics, system demand, and capacity deficiency.

Customers will be notified by 6 p.m. the day before critical hours are expected to occur. Notification will be made by one or more of the following methods: automated telephone message, text message, e-mail, or presentment on an in-premise display unit furnished by Detroit Edison.

Detroit Edison said that, at this time, it is not requesting any change in the rates or cost of service to other customers. Thus, the approval of the voluntary Experimental Dynamic Peak Pricing Tariff will not alter any existing electric rates paid by Detroit Edison's other customers. Detroit Edison did not elaborate on how it plans to later reconcile any difference between the cost to supply the pilot customers and revenues received from such customers.

Briefly:

Acclaim Energy Advisors Seeks Maine Broker License

Acclaim Energy Advisors applied for a Maine electric broker license to serve medium and large non-residential customers in all service areas.

StarTex Power Receives Better Business Bureau Pinnacle Award

StarTex Power has been awarded the 2010 Better Business Bureau of Houston Pinnacle Award, which is the top honor awarded to a company by the Better Business Bureau, reflecting, "extraordinary commitment to ethical practices and caring customer service." The Pinnacle Award is given to only one business per industry. The award honors companies that demonstrate exceptional customer care, management, and product quality, while exemplifying trust and honor with customers and other corporations. "We are extremely honored to receive an award of this stature from the Better Business Bureau," said Bob Zlotnik, CEO of StarTex Power. "Our philosophy is simple. We treat our customers like family, and we always look for ways to improve our services for them. This award is validation that we are fulfilling that promise," Zlotnik said.

Lawsuit Against Stream Energy Dismissed

A federal RICO lawsuit filed in Georgia last fall against Stream Energy and its Ignite marketing arm has been dismissed by the U.S. District Court, Northern District of Georgia, Rome Division. Stream called the suit, filed by The Clearman Law Firm, a "copycat" action that followed an almost-identical lawsuit in Texas which was dismissed by the Federal District Court at Houston during November 2009 (Matters, 11/10/09). The Georgia federal court agreed with the earlier reasoning of the Southern District of Texas federal court in finding that former associates of Stream's Ignite sales force cannot avoid prior agreements to resolve any disputes with Stream or Ignite through arbitration proceedings.

Credit Suisse Energy to Relinquish REP Certificate

Credit Suisse Energy LLC asked to relinquish its Texas REP certificate, informing the PUCT that it has never served customers.

PNC and Integrys Energy Services Complete Financing for Solar Project at Harvard

PNC and Integrys Energy Services announced the completion of a $3.3 million solar project financing deal related to photovoltaic units on a Harvard University building in Watertown, Mass. The 500-kW unit will produce over 600 megawatt-hours of energy annually, which will be sold to Harvard via a 25-year PPA, with the net price of the energy currently pegged at or below the cost of power from the grid. Integrys Energy Services developed, installed and commissioned the roof-top solar units. "We see great value in our relationship with PNC as we seek to continue to broaden and expand our delivery of clean, renewable solar energy to current and future customers," said Joel Jansen, managing director of energy assets at Integrys Energy Services.

N.Y. PSC Approves Expansion of Classes Eligible for Rider U Program

The New York PSC approved Consolidated Edison's petition to allow customers in service classifications 1, 2, and 7 to participate in the Rider U - Distribution Load Relief Program, as long as the other program requirements, such as a minimum number of enrolled kilowatts and the installation of billing interval meters, are met (10-E-0169). The PSC agreed that expanding eligibility to additional service classes will provide an opportunity for ConEd to achieve greater load reductions when the program is called by creating a greater pool of potential participants. ConEd estimated that, with the expanded eligibility, an additional 4 MW could be enrolled in the program for the 2010 Summer Capability Period.

PSNH ... from 1

costs include the non-fuel costs of generation including non-fuel O&M, depreciation, property taxes and payroll taxes, uncollectible costs attributable to Energy Service sales, and a return on the net generation investment. These are all costs associated with PSNH's ownership of generation.

PSNH's owned generation provided approximately 56% of PSNH's energy needs in 2009. When combined with IPP purchases, IPP buyout replacement purchases, and the Vermont Yankee purchased power arrangement, which cumulatively contributed another 12% of energy requirements, PSNH met 68% of its energy needs with sources other than market purchases. The remaining 32% of PSNH's energy needs were met by spot market purchases (4%) and bilateral energy purchases (28%).

Approximately 1,189 GWh of on-peak energy were purchased bilaterally at an average cost of $98.12 per MWh (a total expense of $116.7 million). Some 88% of the on-peak bilateral energy was procured via fixed-price monthly contracts in order to address the forecasted supplemental requirements and planned unit outages. Another 8% was procured via fixed-price, unit-contingent contracts with the Bethlehem and Tamworth Generating Plants. The remaining bilateral energy (4%) was procured via fixed-price short-term arrangements (e.g. daily, weekly) to address unplanned outages and higher load periods.

In addition, approximately 114 GWh of on-peak energy were procured via the ISO-NE hourly spot market at an average cost of $51.89 per MWh (a total expense of $5.9 million).

Approximately 696 GWh of off-peak energy were purchased bilaterally at an average cost of $78.74 per MWh (a total expense of $54.8 million). Some 84% of the off-peak bilateral energy was procured via fixed-price monthly contracts, while 13% was procured via fixed-price, unit-contingent contracts with the Bethlehem and Tamworth Generating Plants. The remaining bilateral energy (3%) was procured via fixed-price short-term arrangements (e.g. daily, weekly).

In addition, approximately 145 GWh of off-peak energy were procured via the ISO-NE hourly spot market at an average cost of $41.58 per MWh (a total expense of $6.0 million).

The combined expense for all supplemental energy purchases was $183 million.

PSNH also reported that for the Stranded Cost Recovery Charge (SCRC), the net under-recovery in 2009 was $3.9 million, primarily due to higher above-market IPP costs.

Demand Response ... *from 1*

that may be experienced through the increased participation in demand response programs," Hess said.

Specifically, Hess cited the following as concerns:

- The use of LMP for payment of demand response in energy markets, and the potential that over-compensation to demand resources can produce inefficiently large amounts of demand suppression
- The limitation to the comparability of demand resources to supply resources in the FERC model. While demand and supply resources might have the same impact to balancing load and generation, there is a difference in RTO balancing of payments/charges and physical availability between the two alternative resources
- The over-compensation of demand resources providing a suppression of real-time prices, and a disincentive to investment in other new entry
- The specter of the creation of additional costs to be recovered in the FERC model, and the prospect that such costs will either be assigned to the LSEs, or passed on to non-participating customers directly

Hess echoed Commissioner Philip Moeller's sentiment in his partial dissent, and said that more analysis is needed before FERC action. "This analysis must be done on a very granular and per RTO level following the path of dollars that this proposed rule will create so as to identify where the cash flow will come from to satisfy the additional compensation for demand response participants. Demand response participation rates are properly linked to the retail market and the effects of artificially encouraging demand response in the wholesale markets must be carefully and thoroughly analyzed," Hess said.

Direct Energy Services likewise urged FERC to conduct a more measured review of demand response compensation than the *fait accompli* presented in its NOPR. "A notice of inquiry is the preferred course of action," Direct said, since the NOI would allow critical questions to be asked and answered prior to the issuance of a proposed rule.

"The Commission correctly notes that there have been various opinions regarding the correct level of compensation for demand response in numerous proceedings. However, instead of developing a full evidentiary record analyzing the merits and detriments of each proposed methodology, the Commission elects to pick a winner based on anecdotal evidence that PJM's demand response program has suffered [declining] participation due to a change in its compensation methodology," Direct added.

"Commissioner Moeller notes that the PJM Independent Market Monitor concluded that the exact role the change of demand response compensation made by PJM had on participation rates is not known. The Market Monitor observed that while participation rates in the PJM economic demand response program may be lower than previous years, participation of demand response in the PJM capacity market increased 114% between 2008 and 2009. Therefore, to conclude that PJM's methodology for compensating demand response resources is negatively impacting the demand response market is premature," Direct said.

ConEdison Solutions said that it opposes proposals to require all RTOs to compensate demand response programs at the full market price for energy reductions, in all hours, if the customer had not first purchased and was in a position to actually sell the unused energy. "Paying the full market price for the 'supply equivalent' of energy, above and beyond the cost savings for reducing demand, is a direct subsidy to those consumers that participate in the demand response programs and would be treating the demand response as a superior product to increased generation. The costs associated with this subsidy must ultimately be borne by the remaining consumers in the market," ConEdison Solutions noted.

Though not taking a position on compensation per se, Integrys Energy Services expressed concern with FERC's proposed standardization across all RTOs, given that each RTO has incorporated demand response resources into its programs slightly differently. "For example, many RTO/ISOs have incorporated demand response into their resource adequacy requirements/rules, affecting such matters as equivalent capacity value, equivalent load value, operational availability and requirements for interruptions, etc. Changes in a demand response proposal could, therefore, have adverse effects on resource adequacy programs or other programs where demand response has been incorporated. As a result, Integrys Energy submits that the Commission should continue to permit regional differences in implementation of demand response programs."

The National Energy Marketers Association, however, strongly supported FERC's NOPR, stating that, "demand resources should have the equal ability to participate in the markets with supply resources [and] ... [t]he Commission's proposal will achieve this result."

"NEM strongly supports the Commission's proposal to compensate DR resources at LMP. In fact, NEM would submit that LMP represents a minimum wholesale price for demand response."

NEM further argued that the retail value for demand response should capture numerous important externalities, including societal benefits, environmental benefits, future avoided costs, and the reduction of congestion-related costs.

While cloaked in the aura of promoting cleaner energy, Exelon noted that the "subsidy" inherent in FERC's NOPR would not only, "undermine the competitive energy markets," but would actually encourage behind-the-meter generation which may be more polluting and less efficient (e.g. diesel generators) than the generation it displaces. Exelon further argued that accurate shortage price signals would properly incentivize demand response resources.