

Retail Energy

Combined gas/electric standards board meeting cautious response from parties

If there is some good to be gleaned from the California energy situation and its resulting impact on other states' restructuring efforts, it may be that it is buying time to set up a combined gas/electric standards board, an Edison Electric Institute official suggested.

The Gas Industry Standards Board has floated its plan to create an Energy Industry Standards Board and numerous groups are considering what their roles would be and if the idea has merit. As currently envisioned in a revised model, an EISB would be made up of four quadrants: wholesale gas, wholesale electric, retail gas and retail electric, with GISB representing the wholesale gas quadrant (*RE*, 11 May, 12).

The American Gas Assn. is expected to take the lead in defining the retail gas quadrant, and officials with the trade group are considering such issues, an AGA spokeswoman said. The next GISB board of directors meeting is in September, when a vote on the EISB framework is expected. AGA, like several other organizations, hopes to provide input by then, the AGA spokeswoman said.

An EISB "would conduct standards development activities with respect to the electronic exchange of information, record and data formats, communications protocols and related business practices that streamline the transactional and coordination processes of the retail electricity and retail natural gas marketplaces," the GISB proposal says. It would not develop standards for physical facilities, safety,

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Kent. PSC approves gas hedging plan for ULH&P; utility pleased with result

The Kentucky Public Service Commission has approved Union Light, Heat and Power's pilot gas hedging program for the upcoming heating season. A spokesman for the utility noted that the commission made only a few changes in its proposal and it is generally pleased with the result.

The company is especially pleased that it received assurances from the PSC that ULH&P won't be second-guessed on its hedging policy and be forced to make up the difference between hedged and actual market prices for gas, the spokesman said. Without those assurances, utility shareholders "could only lose and not gain if we adopted a hedging practice," he said.

With the PSC's approval of the program "our shareholders are protected against claims that we didn't buy the absolutely lowest-price gas available," he said.

In its order, the commission acknowledged that the objective of paying the lowest price for gas often conflicts with the goal of mitigating price volatility. When utilities hedge their gas costs, there is the potential for ratepayers to pay more gas if market prices fall below he hedged

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New Power proposes bill giving FERC new authority to set retail market rules

Retail marketer New Power, which says it serves more than 700,000 gas and electric customers in 10 states, has asked Congress to give federal regulators power to set uniform business rules so that wholesale and retail suppliers can operate more easily across the country.

In testimony prepared for a House hearing today (Friday), New Power's Kathleen Magruder pointed out that various rules in each state, and often within states, present expensive and often insurmountable barriers to competitive suppliers.

The company, which is a joint venture of Enron, America Online and IBM, has drawn up a bill that gives the Federal Energy Regulatory Commission authority over power sales right up to customers' meters. Disputes over state-federal authority in this area have been legion.

According to a summary of New Power's bill, it would clarify that FERC can order utilities to permit installation of time-of-use meters at customers' homes. And Congress should require utilities to settle and permit billing on the basis of the meters' data. "Texas has made a positive step by requiring that all utilities use the same protocols

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for enrollment, billing and other necessary processes,” Magruder’s testimony says. “That model should be mandated for all other states.”

Further, New Power proposes, Congress should mandate that FERC and the Federal Trade Commission, within a year, issue rules setting uniform business practices at both wholesale and retail levels. Gas and electric industry groups “have struggled over the last two years with the issue,” the company noted (see related story on page 1). But because there is no mandate for standard practices, and “and because retail issues have never been seriously discussed, New Power is today asking that Congress insert itself into this process.”

The industry groups’ work “need not be ignored,” the company said. “We would encourage the FERC and the FTC to impanel a stakeholder group to begin with the work that has already been done and proceed from there. We would, however, ask that the stakeholder group be comprised of representatives from all affected industry sectors. Too often, marketers who serve residential customers do not get a seat at the table.”

Further, New Power said, Congress should mandate that FERC adopt governance protocols for regional transmission organizations that allow all affected parties, including retailers that are not affiliated with utilities, to be members of RTOs and have a voice in their governance.

COMPETITION

Retail electric rates dropped up to 36% since competition took hold, EPSA says

Seeking to “debunk the myth” that a return to cost-based wholesale electric rates across the country would curb skyrocketing energy prices, the Electric Power Supply Assn. on Monday released a report that claims retail electric rates have, in fact, dropped over the past 15 years as electricity competition has taken hold.

The report, “Assessing the ‘Good Old Days’ of Cost-plus Regulation,” said competitive trends have played a significant part in driving down retail energy prices by as much as 36% for some customers since 1985. While many pundits have called for a return to cost-based rates in the wake of California’s restructuring debacle, the report argued that electricity rates were considerably higher before the push towards wholesale competition began.

“People seem to forget that, in the days of cost-plus regulation between 1970 and 1985, inflation-adjusted electricity prices actually increased 25% for residential customers and increased 86% for industrial/commercial customers,” Craig Roach, principal of Boston Pacific, a consulting firm that wrote the report, said at a Washington news conference.

The price decline began when Congress passed the Public Utilities Regulatory Policies Act in 1978, which brought about widespread use of cogeneration facilities and other renewable resources. The study found that from 1985 through 1999, inflation-adjusted electricity prices dropped on average by 30% for residential customers and

36% for industrial and commercial customers.

After PURPA, utilities in 1984 were required to issue solicitations for new cogeneration plants, which the report said helped give smaller “qualifying facilities” a larger role in the marketplace. Then Congress in 1992 passed the Energy Policy Act, which gave the Federal Energy Regulatory Commission authority to implement open access, leading to FERC’s landmark open-access rules.

EPSA acknowledged that competition was not the only factor at work in pushing prices down: Declining fuel costs, slowing inflation and depreciation of high-cost plants also played a role, the report noted. But Roach said all these factors “happened under competition’s watch,” claiming that the move towards open access helped spur the declining prices. And even though California’s flawed restructuring scheme has resulted, at least temporarily, in higher prices, EPSA said the state’s problems were caused by simple supply and demand problems, not competition in general.

Ontario grid operator touts readiness; but utilities lag in preparing for choice

Good news and bad seem to be propelling Ontario toward starting full retail electric competition next spring, with a grid operator touting its readiness while utilities appear to be behind schedule.

Canada’s most populous province initially planned to implement customer choice last November, but it pushed the date back because of concerns about computer problems and other systems. In April, the provincial government said it planned to implement competition by May 2002, leaving open the possibility that the start date could be as early as this fall (*RE*, 27 April, 5).

That possibility is now out, however. A spokesman for the Ontario Energy Board on Monday said that “only a few” of the more than 100 electricity distribution utilities in the province are on track to meet the Aug. 10 deadline for completing the second stage of “self-certifying” that they will be fully prepared for competition.

The OEB suggested in a July 23 letter to municipal utilities and other distributors that the Aug. 10 deadline be pushed back more than four months, to Dec. 14. Parties have until July 27 to comment on the proposed date change, and the OEB plans to review comments and issue a final ruling in August, it said.

The OEB spokesman said the proposed delay means that a fall 2001 start for competition “is now impossible.” He noted that Ontario officials have repeatedly stated their intention to implement competition in either the fall or spring, when electricity demand is lower, meaning that a spring 2002 start date is likely. He added that the OEB “sees no reason” why a delay in self-certification by utilities would prevent competition from being implemented next May.

Meanwhile, the province’s Independent Electricity Market Operator said July 19 that it successfully completed a six-week simulation of competitive conditions. Derek Cowbourne, the IMO’s vice president for market services, said

the IMO “ran a simulated open wholesale electricity market based on real supply and demand conditions from mid-May until the end of June.” Cowbourne called the test, which involved the IMO and 19 market participants, “a resounding success,” and said it brings the province “a significant step closer” to the customer-choice era.

The IMO said the so-called “uncoupled operational dry run” involved operating the wholesale and retail market “based on the real supply and demand conditions of the day.” In addition, more than 50 specific market scenarios were “added to the mix to ensure that virtually all possible market conditions would occur during the six weeks.”

The only significant differences between the test and the “live market,” the IMO said, were that during the simulation generators did not adjust their output in response to the market conditions, and funds were not exchanged.

An industrial energy user participating in the test said he agreed with Cowbourne’s characterization of it as a success. The simulation “gives me great confidence in the future of Ontario’s wholesale electricity market. If a problem was identified [during the test], it was quickly solved,” said Francois Abdelnour, manager of energy planning at steel company Ivaco Rolling Mills. The test “allowed us to learn a great deal about the systems, procedures and general operation of the market,” Abdelnour said.

The IMO said it has begun working with other market participants “to ensure they can also undertake all the essential market and business functions” by the time customer choice is implemented.

Maine PUC orders RFPs for small users, delays large users to promote switching

The Maine Public Utilities Commission this week issued requests for proposals to supply standard offer electric service to residential and small business customers of Central Maine Power and Bangor Hydro Electric starting next March 1.

In a related order last week, the PUC decided to delay issuing similar RFPs for standard offer power for CMP and Bangor Hydro medium and large business customers for the same period. Instead, the PUC said it wants to encourage competitive suppliers in the state to sign up more medium and large users in the coming months. Issuing an RFP for March 2002 contracts at this time and setting standard offer rates that could be lower than current rates would inhibit users from switching to a competing supplier, the PUC reasoned.

In an effort to boost the number of switches, the PUC also ordered Bangor Hydro and CMP to provide full lists of their medium and large customers, which number about 10,000, to all competitive suppliers in the state by July 23. The power sellers had claimed that this would allow them to make large-scale mailings to potential customers, aiding their sales efforts, the order related.

Marketer groups had told the PUC that they had no cost-effective way to advertise to medium and large users and direct mailing is the only logical approach. While the sellers asked for lists of only those users that remain on

standard offer service, the utilities said it would take too much time to break down the lists that way.

In its decision, the PUC said providing lists of all customers without specifying which remained on standard offer power would be quicker and protect sensitive business information. The lists will only contain names and addresses and not usage information since that cannot be divulged without user consent. The power sellers agreed to use the lists only for their own marketing efforts and not share them with other parties, the PUC related.

In the order on the RFP for residential and small commercial users, bidders were asked to submit non-binding letters of intent to bid by July 31 and final offers by Aug. 7. The bids could provide electricity for terms of one, two or three years. The PUC said the total power needed for the small-customer classes will be about 4 million MWh/year. For more information about the RFPs, contact Faith Huntington, with the PUC, at (207) 287-1373.

The PUC also said CMP and Bangor Hydro will carry out separate solicitations to buy energy on a wholesale basis to supply the same small-user classes. The PUC plans to compare its own retail offers and the utility wholesale offers and decide later this year which deals to approve.

Under current contracts, CMP small users pay 4.089¢/kWh for standard offer power and Bangor Hydro small users pay 7.3¢/kWh. Because of those rates, virtually all residential and small business customers take standard offer service instead of buying competitive supplies, and the PUC said current market conditions make it likely that trend will continue. For that reason, the PUC decided that the best strategy was to go ahead with the RFPs.

In the case of the medium and large users, standard offer rates dramatically increased in March because of the high cost of power contracts closed around the end of last year. CMP medium users are now paying standard offer rates of 8.52¢/kWh and large users an average of about 9¢/kWh. Bangor Hydro medium users pay 7.3¢/kWh and large users an average of 7.7¢/kWh.

Currently, about 81% of CMP large users and 29% of its medium users have dropped standard offer service in favor of competitive supplies, the PUC noted. For Bangor Hydro, the migration rate to the competitive market is 41% for large users and 9% for medium users.

While deferring a new RFP for those customers for now, the PUC said it may change its entire pricing approach for those classes when it does solicit new suppliers, probably later this year. The PUC said it may propose pre-set standard offer rates below current prices for the CMP and Bangor Hydro users and ask bidders to meet the rates. The order said the PUC would seek comments soon on a new bidding system and on what the pre-set rate should be.

Ohio consumer education campaign for electric choice selects new PR firm

On a relatively shoestring budget of \$120,000, Pierce Communications, a Columbus, Ohio-based public relations firm, plans to do some “old-fashioned, shoe-leather

work” during the next 12 months to spread the word about the state’s Electric Choice program, the company’s president said.

Pierce was chosen by the Ohio Public Utilities Commission last week to run the second year of the state’s Electric Choice consumer education program, which has a five-year budget of \$33 million. Pierce and Edward Howard & Co., another Ohio-based firm, were the two finalists of 10 companies that submitted proposals in response to the PUC’s solicitation (*RE*, 8 June, 7).

The PUC, Ohio Consumers’ Counsel and the state’s investor-owned electric utilities are conducting the campaign to inform residents about the choice program, which allows customers to choose their electric suppliers.

Pierce was selected because it had the support of the PUC staff, OCC and the utilities, the PUC said. The recommendation letter in support of Pierce said the company “not only has a comprehensive knowledge of the issue’s history, but a strong familiarity with the stakeholders and the current issues challenging the campaign. Pierce’s plan details realistic goals, presents practical strategies and provides a credible and sound means to evaluate the program.”

Last year, four out-of-state companies - Fitzgerald & Co. of Atlanta, Ga., The Center for Research and Public Policy of New Haven, Conn., and two New Hampshire firms, High Point Communications and Gregory S. Franklin Associates - were hired to handle various aspects of the campaign’s first year, which ended May 31.

Because the program’s budget contains a maximum of \$120,000 for the second year’s work, Pierce must make judicious use of its resources, Gene Pierce, the company’s president, told *Retail Energy*. “We’re basically going to perform the public relations function needed to tell people about Ohio’s Electric Choice program,” he said.

Despite the reduced budget for the second year, Pierce does not regard his company’s task as daunting. Ohio’s still fledgling choice program has its share of critics, many of whom point to a dearth of true competitive options in most areas. Pierce, as befits a PR company executive, will try to counter the criticism with a positive message. “We’re going to try to preach a little patience to some people,” he said.

Ohio’s choice program, he noted, includes a “good aggregation feature” that allows customers to team up to choose their supplier. Such is the case in northeast Ohio, where the Northeast Ohio Public Energy Council was formed to aggregate electricity — and now, natural gas — for nearly 100 cities and towns.

New Power says PJM capacity charges are killing competitive retail market

Asserting that unreasonably high capacity charges in the PJM Interconnection are killing competition in Mid-Atlantic states, retailer New Power has asked the Federal Energy Regulatory Commission for relief from the charges within 60 days.

The company has proposals for a different approach

to charges that would be fairer to retail suppliers. “We’ve tried different fixes, but they haven’t made the market work,” lamented New Power General Counsel Marc Manly. “If this is corrected, it will completely fix retail markets.”

New Power is supplying about 250,000 residential users in the PECO Energy territory, and more in PJM and other states. It told FERC that under PJM’s Reliability Assurance Agreement (RAA), “load-serving entities” (LSEs) that do not own power plants are required to contract for sufficient capacity to cover their loads. They pay an installed capacity (ICAP) rate for this power. If they fall short, they must pay the “capacity deficiency rate” (CDR) — set at \$177.30/MW/day — which compensates generators for excess capacity that they contribute to the pool.

Making matters worse, New Power says, is a recent PJM rule requiring LSEs to contract for capacity over an entire season. If they fall short for even one day, LSEs must pay the CDR penalty for the entire season. PJM said seasonal scheduling improves reliability by forcing parties to make long-term commitments. Suppliers would not share in the CDR revenues unless they committed plants to PJM for an entire season, the PJM rule noted.

LSEs are squeezed by this system because “we need the capacity come hell or high water,” Manly said. “There are so few suppliers with capacity, that they can withhold supply until we blink,” he told *Retail Energy*. As a result, suppliers have pushed up the price for ICAP, so that New Power and other LSEs have been paying more than \$160/MW/day, he said. This has helped force many retailers out of the market, said Manly, noting that retail competition is moribund in Pennsylvania, New Jersey and Maryland (*RE*, 6 July, 1).

PJM’s Marketing Monitoring Unit is concerned about the problem, but its proposed solutions have not worked, Manly said. After starting the seasonal system, PJM held two ICAP auctions, “but the suppliers didn’t play” and prices remained high, Manly added. Again, the problem is that suppliers have enormous leverage over LSEs, and can simply withhold their capacity and sell into another market, he said.

PJM also decided to spread the CDR revenues among more parties, including LSEs that meet capacity obligations, as well as suppliers. It reasoned that this approach would dilute the CDR payments suppliers could collect, and encourage them to offer less expensive capacity, instead of waiting for LSEs to fall short, and then collecting CDR revenues. That also provided little improvement, Manly said. He added that the spot market for ICAP is too risky, because an LSE that fails to arrange sufficient capacity for the next day suffers a CDR penalty for the rest of the season.

As a short-term solution, New Power proposed resetting the CDR on a daily basis, at the higher of the marginal cost of the least efficient capacity resource required to make up the deficiency on that day; or the “Alternate Value,” the difference between prices on that day at the Cincergy hub and PJM’s western hub.

For the long term, New Power would like PJM to

impose an administrative charge for reliability on all LSEs, including those that own generation. The charge could be based on the amount of all current ICAP revenues and CDR penalties, Manly said, and he provided a "rough estimate" of 0.116¢/kWh. It would help non-generating LSEs like New Power because the charge would apply to all LSEs, even those that own plants, and thus would spread the burden among more parties.

PJM could distribute the revenues among suppliers, Manly said. It might also use the revenues to provide subsidies or low-interest loans to generators planning to add capacity. PJM could adjust those subsidies and loans over time, depending on how much capacity the ISO needs, he added.

An administrative charge does not conflict with the ideal of competitive markets, Manly said, because "open markets don't take care of reliability. PJM has tried to take care of reliability through markets, and it hasn't worked."

New Power asked FERC to act within 60 days because it says the ICAP problems are crippling competition in the region. It also wants the commission to order refunds of the amount that "unjust and unreasonable" charges for ICAP and CDR penalties exceed the charges that FERC determines are appropriate.

TECHNOLOGY

Power line technology firm lines up utility partner; field tests continue

While full commercial use of its services is about a year off yet, a company pursuing power line telecommunications (PLT) technology continues to line up utility partners and conduct field tests of the technology.

Ambient Corp. signed a memorandum of understanding with Cedar Falls Utilities, a combination municipal utility in Iowa, that outlines a plan for bringing the technology to commercialization in the next 12 to 18 months. The agreement sets out the terms of a strategic alliance between Ambient and Cedar Falls that allows the muni to use Ambient's PLT technology to provide customers with a host of such services as telephony, Internet access, load balancing, real-time power monitoring and more.

Like Powerline Technologies and firms that are deploying the technology in Europe (*RE*, 13 April, 15), Ambient offers utilities the chance to use their power lines to send high-speed data signals, which also provides the utility with services such as automatic meter reading, power quality monitoring, load switching and balancing and other niche utility applications.

High-speed data signals degrade as they travel over power lines, requiring repeaters or boosters to be placed along the lines at certain intervals, noted Pini Althaus, director of business development for Ambient. PLT technology allows the signals to bypass transformers, which have been an obstacle to using power lines for such services in the past.

Ambient this week reported results of field tests on energized power lines in residential neighborhoods, on both low-voltage and medium-voltage lines. "We've gone around to quite a few utilities in the U.S. and performed tests on their lines," Althaus said. Ambient previously announced a partnership with Consolidated Edison of New York, but Althaus declined to identify other utilities because they have not signed agreement with Ambient. "It's quite a large number" of utilities and their initial reaction to the tests has been "very positive," he said.

The tests were performed without any adverse effects on power transmission, Ambient emphasized. At one location, it reported sending 18.8 megabytes/second over a distance of 0.2 miles, or 1,028 feet, on medium-voltage lines. At another location, it sent 15 megabytes/second about 1,000 feet on underground medium-voltage lines.

John Joyce, chief operating officer of the company, said the tests doubled the distance covered in previous efforts. "I'm not talking about drawing-board potential. I am speaking of real distances, over real energized electric wires. The technology is real, and we remain on target in our timetable towards full commercialization," Joyce said in a statement.

One regulatory issue associated with PLT technology is that telecommunications firms would view utilities as competitors, so Ambient's arrangement with each utility may vary, Althaus noted. Cedar Falls, for instance, has a telecommunications arm so it is very interested in what Ambient can provide, related David Martin, director of customer services and business development for the municipal utility.

The MOU with Ambient contemplates an alliance that will have technical parameters set by the utility, Martin said. "We're acquainted with how far you can throw a data signal before repeaters are needed, so we'll be judging their product based on whether it meets or exceeds those parameters," Martin said.

The cost associated with PLT also needs to be less than adding fiber-optic cable because "we could do that on our own," Martin noted. Ambient is marketing PLT as less expensive than adding cable, but because Ambient has not tested equipment on Cedar Falls lines yet, so "we'll have to see where they come in" in terms of cost, Martin said.

"We can compete with fiber on a cost-per-mile basis," Althaus said, because the power lines are already in place and offer more efficiencies compared with building a fiber-optic network. Citing competitive reasons, he declined to offer cost estimates for using PLT technology.

From the perspective of a muni, PLT could provide a complementary platform that "we feel will be needed in the future" to enhance customer service, according to Martin. The memorandum of understanding "emphasizes that it is not just the large urban utilities that stand to benefit from the PLT revolution, but smaller municipal and rural utilities have a major role to play as well," said Mark Isaacson, CEO of Ambient.

In addition to working on sending signals farther, the next step in Ambient's efforts will be multi-point testing,

which involves sending data signals from one power line to multiple lines, Althaus said.

LOAD REDUCTION

Duquesne plans to pay large customers market rates for reducing consumption

Joining other utilities that provide market-based compensation for load-reduction efforts, Duquesne Light said it would pay market rates to large customers that cut their demand when supplies are tight.

Duquesne's voluntary program, dubbed Energy Exchange, is open to users that can reduce their demand by at least 500 kW, either by shedding load or running on-site generators. Duquesne will continue to operate its traditional curtailment programs, which offer customers lower rates throughout the year in return for the right to trim load when needed.

Pittsburgh-based Duquesne sold all of its power plants to Orion Power Holdings, and it has a contract with that company to supply all of its needs through 2004. Joe Frank, Duquesne's manager of industrial and commercial accounts, explained that the utility will ask for reductions when it gets called by Orion. There are no set payments, but Orion will determine how much the reductions are worth, based on market prices and plant availability, he said. Duquesne will pass along those values to customers, minus a small administrative fee, according to Frank.

Frank told *Retail Energy* that he does not expect payments to fall below 30¢/kWh, since Orion likely will call when peaks are high and supplies are tight. When Orion contacts Duquesne, the utility will e-mail participants, who will then use passwords to a special Website, he noted. The users decide how much load they can reduce at which hours. Duquesne may call for cuts on the same day, or for the day ahead. If the user pledges a reduction and then realizes later that it cannot provide the full cut, Duquesne will still compensate that customer for the percentage it can reduce. It will also pay for reductions beyond the pledge, Frank said.

Duquesne recently contacted its largest customers about the program and has already signed up about 60 MW, which exceeds expectations for so early in the program, Frank said.

PPL Electric Utilities recently started a similar program, paying big users 75% of the market clearing price in the PJM Interconnection (*RE*, 1 June, 3). The New York Independent System Operator offers similar incentives.

STATE REGULATION

Calif. Assembly recesses without passing SoCal Ed bill, early return possible

The California Legislature's push for a bill to prevent Southern California Edison from declaring bankruptcy has stalled after it became clear that a majority of Assembly

members could not agree on any one proposal.

Following work on the state budget, the Legislature last week was scheduled to recess for a month, but an aide to Assembly Speaker Robert Hertzberg said the Assembly could be called back into session before its scheduled Aug. 20 return date if an acceptable plan for rescuing the utility is developed.

Hertzberg created a working group of five Assemblymen to produce an acceptable bill before Aug. 15, the deadline for legislative action under an April 6 memorandum of understanding between California Gov. Gray Davis and the utility. Hertzberg's aide on Thursday said the speaker is hoping to take a vote on the effort as soon as Friday by calling back 80 Assembly members from summer recess.

The working group, composed of Assembly Speaker Pro Tem Fred Keeley and Democrats Rod Wright, Jackie Goldberg, Juan Vargas and John Dutra, was formed to focus on revising an MOU bill that passed the Senate over the weekend.

Brian Bennett, SoCal Ed senior vice president of external affairs, said the utility has no desire to file bankruptcy because the Legislature failed to act before summer recess. "We're closer to a resolution than we have ever been," he said. "We want to keep out of bankruptcy. It is not a viable alternative."

The utility, however, cannot prevent involuntary action by its creditors, many of whom viewed the Davis MOU as their best chance to get paid, Bennett said. "We're at their mercy," he said. And if the Aug. 15 date lapses, the bankruptcy court may be the utility's only option, he added.

In another development, The California Department of Water Resources said it would not require an electric rate hike through 2002 to cover its wholesale power spending and repay a \$13.4-billion revenue bond issuance expected in October.

In its revenue requirement released Sunday, the DWR requested an average 1.65¢ of the state's 3¢/kWh rate increase that began on June 1. Joseph Fichera, Saber Partners CEO and financial advisor to Davis, said that DWR anticipates using \$12.5 billion of the bond issuance, allowing for a \$900-million cushion should the agency's projections of power costs be incorrect. The DWR revenue requirement will be reviewed publicly before being acted on by the California Public Utilities Commission in August.

Electric service to generating plant presents conundrum in Rhode Island

Does a power plant become a utility's retail customer when its generator is down and it must rely on utility service to keep its office equipment operating? That's the half-million-dollar question under debate in Rhode Island by subsidiaries of PG&E National Energy Group (NEG) and National Grid USA.

Narragansett Electric, a utility owned by National Grid, contends that NEG's 495-MW Manchester Street Station owes it \$525,000 in delivery charges going back three years. The charges are for Manchester Street's use of the utility's distribution lines when the plant is idle and it must rely on outside or "station service" power

for its offices, Narragansett said in a filing at the state Public Utilities Commission.

NEG, however, contends that it does not owe Narragansett the money because the plant takes wholesale service, rather than retail delivery from the utility. When its generators are down it receives power from other NEG plants by way of transmission lines under the Federal Energy Regulatory Commission's jurisdiction, the generator said.

Manchester Street was once owned by Narragansett, but was sold when the utility's parent divested its generation under state restructuring rules in 1998. Neither party is arguing that Manchester Street owes money for power supply, the battle is over what path the power takes on its way to the plant. Does it travel via FERC-regulated transmission lines or utility-owned distribution lines?

Narragansett says Manchester Street is neither a standard offer nor last-resort customer and there is no power charge associated with the bill because Manchester Street obtains the electricity through the New England Power Pool. Instead, the utility charges the generator a discounted high-voltage rate, which includes costs for distribution, stranded investment, transmission and demand-side management.

The unpaid bill creates a quandary for Narragansett in that it would ordinarily shut off service to the customer, but it can't in this case because the Manchester Street Station provides power for the utility's standard offer customers. So it has asked the PUC for a ruling.

Narragansett said the bill has not been paid since September 1998, but NEG countered that it didn't receive a bill until February 1999, and then it immediately explained to the utility why it would not pay. "It is Narragansett who failed to diligently pursue this matter further since 1999," NEG told the PUC.

NEG appears to claim that station power does not fall under state-regulated rate structures, but such arguments have been overturned by FERC and other state commissions, according to Narragansett. In particular, Narragansett said that a March 14 FERC order settled a similar dispute in PJM by ruling that station service is for end-use and is not a wholesale transaction subject to FERC jurisdiction.

Similarly, the New York State Public Service Commission ruled last September that station service and start-up service for generators served by Consolidated Edison fall under state rate regulation, Narragansett said. "Generators are not subject to any special treatment," Narragansett told the PUC.

NEG disputed Narragansett's use of FERC precedent, saying that FERC decides such issues on a case-by-case basis. Further, Narragansett and Manchester Street have an interconnection agreement filed with FERC that says the power plant is connected to Narragansett by way of a high-voltage transmission network to be used to move station service power. That agreement precludes Narragansett from seeking retail charges for the service, according to NEG.

NEG says it already pays Narragansett for the service though an annual facilities charge. In addition, the plant buys transmission service from both Narragansett's parent and the New England Power Pool under a five-year transi-

tion schedule that will end in 2003. NEG asked the PUC to dismiss Narragansett's claim and it filed with FERC for a ruling that the Manchester Street plant receives transmission service.

Okla. regulators tell gas and electric utilities to hedge gas purchasing plans

Aiming to soften the impact of volatile wholesale gas costs, the Oklahoma Corporation Commission on Wednesday told the state's largest gas and electric utilities to develop hedging plans for their gas purchases. No due date for the plans was ordered.

The directive "is a concerted effort to find solutions to the impact of high market prices" for gas that has plagued Oklahomans and the nation, the OCC said in a statement. Commissioner Bob Anthony said an unfortunate aspect of Oklahoma's law regarding the gas utilities' purchased gas adjustment and electric utilities' fuel adjustment clause "is the automatic pass-through to customers of the risk of fuel price volatility as well as the actual cost of fuel."

The order applies to Oklahoma Gas & Electric, Arkla-Reliant Energy Resources, Public Service Co. of Oklahoma and Oklahoma Natural Gas, the OCC said.

The commission has signed off on Oklahoma Natural Gas' plan to offer customers a voluntary, fixed-price payment plan. The pilot project will begin in the fall of 2002. ONG already is hedging about 40% of its gas purchases this year, an OCC spokesman said.

Similarly, the commission has approved Arkla-Reliant Energy Resources pilot program in which it will hedge up to 10% of its annual gas supplies for the twelve months ending March 31, 2002.

The Commission said it will work with utilities "under a notice of inquiry to consider future hedging plans they may implement to reduce the impact of price volatility on their customers."

Kent. PSC tells distributors to amend gas purchasing plans, will conduct audit

The Kentucky Public Service Commission decided to hire an outside consultant to "conduct a focused audit" on the gas procurement practices of the state's five largest distributors. The commission last week also directed the local distribution companies to make quarterly gas cost adjustment (GCA) filings rather than monthly filings in light of the volatility in wholesale gas prices.

The PSC directed Columbia Gas of Kentucky, Delta Natural Gas, Louisville Gas & Electric, Union Light, Heat and Power and Western Kentucky Gas to consider ways to mitigate the effects of high gas costs on their customers. Specifically, the commission wants the LDCs to consider using performance-based rates, price hedging, alternative gas procurement strategies or increased use of storage facilities.

The commission said the gas cost recovery period will be extended from one year to two years in order to avoid increasing customers' rates. "Reinstating quarterly GCA fil-

ings while requiring that LDCs match their projected wholesale prices to the quarter in which the proposed GCA will be in effect is one means of addressing” the subject of price volatility, the commission noted. “While it is possible that the prices experienced during the 2000-2001 winter will not recur in coming years, the commission finds that some form of preparedness and risk mitigation strategy should be in place in the event of a recurrence.”

Because customers bear the risk of wholesale price spikes, “it is appropriate that they bear the full cost, within reason, of any commission-approved price mitigation strategies,” the PSC said. “Conversely, LDCs that forego developing such strategies may place themselves in the position of sharing some of the price risk to which customers have been exposed in the past,” it cautioned.

Some LDCs are concerned about the risks associated with hedging programs and whether the goals of such strategies conflict with the concept of performance-based rates. Acknowledging that there “is some inherent conflict” between the strategies, the PSC said those risks “can be minimized. In addition, as the Western [Kentucky] Gas program shows, a hedging program can be implemented so as to be separate from a PBR” plan. Western Kentucky Gas was the first distributor in Kentucky to have a hedging plan approved by the PSC (*RE*, 22 June, 9).

The PSC said any plan to obtain low-cost gas, minimize price volatility and maintain reliability of supplies “can be part of a coordinated gas procurement strategy that incorporates performance-based ratemaking with hedging and other price mitigation programs.” The order directed LDCs to “consider offering customers choices as to the manner in which they receive and pay for natural gas service, including fixed price and fixed bill options and allowing customers to develop their own price mitigation strategies.”

Steve Byars, director of regulatory and governmental policy for Columbia Gas of Kentucky, said the commission “has done a very good job” in setting a foundation for utilities to pursue hedging strategies. Columbia Gas, however, is taking a cautious approach and will not use such mechanisms this year, he said.

KCC denies Western Resources’ spin-off; trims utility units’ rate hike requests

The Kansas Corporation Commission has decided Western Resources cannot pursue its restructuring plan, the center of which is the spin-off of Westar Industries, because it would harm ratepayers. In a separate order this week, the KCC significantly trimmed the rate requests of Western Resources’ Kansas Gas & Electric and KPL electric utility units.

In its order on the restructuring plan, the KCC directed Western Resources to file a revised plan within 90 days “to achieve a balanced capital structure and to protect ratepayers from the risks of the nonutility businesses” in a restructured company.

The KCC in May halted Western’s plan, asserting that the spin-off would burden the utility units with significant long-term debt (*RE*, 25 May, 5). Westar is a holding com-

pany with interests in Oneok, international power plants and a security firm, Protection One, which has significant debt on its books, the commission said.

Following hearings in June, the commission issued its decision on Friday, stating that if the plan were approved, “a likely scenario would require [Western Resources] to service the long-term debt through electric rates, while those [Western Resources] shareholders who receive Westar shares in the split-off will receive the benefit of the assets without the burden of the long-term debt incurred to acquire them.”

The harm associated with the spin-off cannot be erased by the company’s planned merger with Public Service Co. of New Mexico “because it necessarily reduces the value to Kansas ratepayers of whatever benefits a merger would bring,” according to the order.

The order made clear that Western could file revised plans, such as selling off Westar assets and applying the proceeds either to Western’s utility operations or to debt retirement. “What we are disapproving is a split-off whose premise is a utility with an unbalanced debt-equity ratio,” the KCC said. It called for a revised plan “detailing a strategy to achieve the stated objective and restore [Western Resources’] financial ratings to an investment grade level of similarly situated electric public utilities.”

A Western spokeswoman on Monday said officials were reviewing the order, but still planned on merging with PNM. “We hope future Western Resources’ filings and joint filings with PNM will demonstrate how issues raised in Friday’s order can be addressed,” she said.

In a separate matter at the KCC, regulators reduced Western’s revenues for its electric utility subsidiaries by a total of \$22.7 million, an overall decrease of about 1.9%.

KPL was seeking an annual revenue increase of \$92.5 million and KGE requested an increase of \$57.9 million. According to Wednesday’s KCC order, KGE’s revenue requirement will be reduced by \$41.2 million, or about 6.6%, while KPL’s revenue requirement will be increased by \$18.5 million, or about 3.3%.

The KCC attributed the rate hike granted KPL to the company’s addition of 514 MW of capacity to serve its customers. KGE’s reduction was based on several adjustments, most notably extension of the operating life of the Wolf Creek generating station.

The KCC said it would determine the actual rate impact to customers in a separate proceeding, after KG&E and KPL file rate design plans based on the revenue requirements. The order directed them to do so by Sept. 20. The commission also reiterated its commitment to work toward eliminating the rate differential between KPL and KGE, which merged into Western Resources in 1991.

The order emphasized that the rates were set based on Western Resources’ corporate structure as it exists today, noting that the restructuring plan has been “lurking in the background” of the rate proceeding. “However, the commission does order that the rates set in this case be interim and subject to refund until it is determined what will occur with the electric utility and the commission is assured that there will not be an electric utility in financial

distress," the KCC said.

Western late Wednesday said the company intends to meet with PNM "in the near future" to discuss the rate order.

Parties considering standards board . . . begins on page 1

reliability or equipment manufacturing and operation, which are currently established by various bodies, according to the model.

Some parties confuse what a standards organization would do and mistakenly assume that it would establish policy, but an EISB "would not set policy," said James Templeton, principal with consultant Comprehensive Energy Services and a GISB board member. At GISB, "we take business practices already being used and try to make it so any computer in the country can handle similar transactions," Templeton told *Retail Energy*.

There is a need for similar action in retail gas and electric operations as companies make sales across various states with differing technical standards, Templeton said. Several parties in Mid-Atlantic states have met to pursue electronic data interchange standards for electric utilities, related Veronica Smith, executive director of the Pennsylvania Public Utility Commission. About 20 representatives of utilities, marketers, software firms and regulators have held meetings over the last few months to form the first regional EDI group for the electric industry, Smith noted.

While separate from GISB's EISB plan, the group's goal is similar; to develop EDI rules in various states that are compatible with each other. Parties in the group provide service in Pennsylvania, New Jersey, Delaware, Maryland, Virginia and Ohio, Smith noted. "For suppliers, more uniform practices will help them bring down costs," she said. "We hope to develop one document that says this is how EDI should be done on a generic basis" in any of the states involved, Smith said. Other states eyeing restructuring could adopt the group's standards, she added.

Although California has given pause to many state plans, "it bought us some time" and "allows us to be more deliberate" in considering the issues associated with an EISB, said Michael McGrath, executive director of retail energy services at EEI. EEI's uniform business practices (UBP) group has been eyeing retail standards and held meetings in Baltimore this week to discuss what a retail electric quadrant might look like, McGrath said. "Our target is to have the scope and governance done by the fall. Whether it will be part of an EISB we don't know yet. That will be decided by the group," he said.

While EEI has been receptive to GISB's EISB model, the trade group won't endorse the idea until it understands the scope and governance of each quadrant, McGrath said. For EEI, the need for wholesale standards is more immediate because state restructuring efforts have slowed and the Federal Energy Regulatory Commission is strongly promoting development of regional transmission organizations,

according to McGrath.

The EISB model does not define a relationship with the North American Electric Reliability Council, and that is an important matter to EEI, according to McGrath. While the model suggests adopting standards developed by NERC's market interface committee, "we don't know who does reliability and who does business practices. We don't want [NERC and an EISB] to be on different paths; those things need to be worked out," McGrath said.

At the last GISB board meeting, it was assumed that NERC's market interface committee would organize the wholesale electric quadrant, while EEI's UBP group would help define the retail electric segment, according to Rae McQuade, executive director of GISB.

NERC's market interface panel is looking at several options in developing commercial practices, one of which is to dovetail into an EISB quadrant, said Gerry Cauley, staff coordinator for the committee. The group has not taken a position on the EISB plan and will take until at least September before reaching any decision, which would then be passed on to the NERC board, said Cauley, who expressed sympathy for GISB as it shops its plan to various parties. "I think what they're trying to do is get a sense of commitment from the industry. We're trying to do that as well," he said.

In comments at FERC this month regarding wholesale electric standards, EEI said "over time, a new electric industry standards-setting organization with attributes of openness, balanced representation and democratic decision-making could become the appropriate forum for resolving coordination and transactions" among RTOs. The most relevant issues for utilities are that "the process should be voluntary, open, inclusive, balanced, consensus-based, industry-driven and focused on practices, not policy. The participants in such a collaborative should determine how best to move forward, whether a full-blown national organization is needed or whether a regional approach would be more appropriate," EEI said.

The comments were in response to questions at a technical conference on RTO issues, where several FERC commissioners questioned parties about their views on an EISB. At the conference, at GISB meetings and elsewhere, FERC commissioners William Massey, Pat Wood and others "have been strident in their remarks" supporting the EISB concept, McQuade said.

And that can only help, because industry's views can be shaped based on how much backing regulators provide, she said. "If regulators get behind it 100%, I think most of the opposition or hesitancy will disappear because parties won't be willing to face regulators or the bad press associated with being the lone holdout" to embracing an EISB, McQuade said. "If state and federal regulators support it or not, they need to make some public pronouncements," McQuade said.

One such pronouncement came last week at the National Assn. of Regulatory Utility Commissioners' summer meeting, where the electricity committee turned down a resolution supporting the evaluation of an EISB. The resolution states, among other things, that

GISB's EISB plan should be considered a "framework document in reaching the objectives of the energy industry and its regulators."

The vote was not a rejection of the EISB concept, but a reflection of some state regulators being "uncomfortable adopting something we're not really familiar with," said Idaho Public Utilities Commissioner Marsha Smith, who chairs NARUC's electricity committee. Once regulators receive more information about an EISB they may well embrace a similar resolution in November, Smith said. "At this point we're waiting to see where our members come down, just like everyone else," added Charles Gray, executive director of NARUC.

Kent. PSC approving gas hedging plan . . . begins on page 1

price, the PSC observed. "This potential, which is part and parcel of any hedging program, does not dissuade us from finding that limited hedging programs can be beneficial," the PSC stated.

ULH&P, the state's fourth-largest local distribution company, has traditionally used pipeline storage facilities as a pricing shield for its customers, the commission noted. Under the hedging program, ULH&P will purchase gas under contracts that will lock in a guaranteed range of prices, using price caps, futures strips or cost-averaging instruments. The program will be in place for the months of November through March, when gas prices typically are at their highest levels, the commission said.

Over the objections of the state Attorney General, the PSC permitted ULH&P to recover the costs of its hedging program through the gas cost adjustment clause contained in tariffs. The Attorney General opposed any hedging plan that would require ratepayers to pay all of

the transaction costs associated with hedging, asserting that ULH&P had not shown that customers would support a hedging program.

While the utility did not survey its customers, it received thousands of calls last winter regarding high gas costs, and the PSC received inquiries sufficient to indicate public support for a hedging plan that mitigates gas price volatility, the commission reasoned. The order noted that ULH&P estimated it could have saved millions of dollars on its gas purchases had the proposed plan been in effect last winter.

In order to guard against excessive transaction costs, the PSC said ULH&P could hedge a portion of its gas purchases, but not all of its supplies. "The commission stresses that although it encourages ULH&P to explore different purchasing practices, ULH&P is still responsible for making prudent decisions in its gas procurement. ULH&P should pursue an objective of procuring wholesale natural gas supplies at the lowest reasonable costs, within a gas supply portfolio that balances the objectives of obtaining low cost gas supplies, minimizing price volatility and maintaining reliability of supply," the commission said.

The ULH&P spokesman noted that the PSC changed some reporting time frames laid out by the utility, but the substance of the proposal was approved "as we had submitted it." The distributor hasn't "nailed down a final number" on the amount of gas it will buy using hedging instruments, he said. The amount "will depend in part on how the process goes in making hedging arrangements and will depend on market conditions as we move forward through the summer," the spokesman said.

The company is planning for a colder-than-normal winter in 2001-2002. And while wholesale gas prices have been dropping, "you don't know what will happen that

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will push those prices way up or push them way down," the spokesman said.

NEW GAS SERVICE

Private firms, munis seek rights to distribute gas in Nova Scotia

More than a dozen parties have notified the Nova Scotia Utilities and Review Board of their plans to seek franchises for distributing gas in the province, a board spokeswoman said Monday.

The list of companies included established utilities willing to provide service to the entire province and smaller municipal firms planning to serve portions of Nova Scotia. Parties had until July 20 to notify the URB of their plans and they have until Aug. 30 to file their applications.

Among the companies planning to file for province-wide franchises were Nova Scotia Ltd. in Halifax, Nova Scotia; Enbridge in Scarborough, Ontario; AltaGas Services in Calgary, Alberta; and SaskEnergy in Regina, Saskatchewan.

Applicants seeking to serve specific areas in Nova Scotia include: Cape Breton Regional Municipality, Kings Community Economic Development Agency, the town of Antigonish, Yarmouth County Industrial Commission, Halifax Regional Municipality, Antigonish Community Gas Cooperative, Wilson Fuel & Scotia Fuels, and the towns of Annapolis, Berwick and Mulgrave.

Sempra Atlantic Gas earlier this month gave notice to the URB that it wants to amend its franchise, which it has held since 1999. That arrangement called for Sempra Atlantic to provide service to 60% of Nova Scotia's residents with operations in all 16 counties by 2007. Citing unforeseen circumstances, including a ruling that prohibits gas companies from placing pipeline under roads, the company backed away from that commitment (*RE*, 13 July, 1).

Sempra Atlantic plans to submit its application with the URB on Aug. 30, a spokeswoman for the company said. The URB has scheduled a hearing on the applications for Oct 15.

RATES

Yankee Gas seeks rate hike featuring service quality plan and revenue sharing

Promising to implement service quality standards and a revenue sharing plan, Yankee Gas Services on Tuesday asked the Connecticut Dept. of Public Utility Control to raise rates for its customers by \$29.2 million, or 7.64%.

If approved, the new rates would take effect January 1, 2002, and would be the first increase since 1992, Yankee Gas said. The rate hike would be the same for all customer classes for the first six to nine months, and then charges to each customer class would change after a new rate design is approved, according to the distributor.

Yankee Gas sought to create an "earnings sharing mechanism" in which all earnings in excess of 100 basis

points above the allowed return on equity be shared equally between customers and shareholders. The company's current ROE is 11.15%, and it asked the DPUC to increase that to 11.78%.

Yankee Gas also requested a "limited infrastructure expansion rate mechanism" to recover capital costs for a \$190-million expansion plan that will be brought into service between 2003 and 2005. The expansion is already under way and in addition to distribution facilities it includes the construction of a new liquefied-natural-gas facility, a Yankee Gas spokeswoman said.

Through the expansion rate mechanism, Yankee Gas is seeking authority to begin passing on the cost of the projects after they are completed, she said. The mechanism would be adjusted annually as the expansion is placed into service and it would "avoid the need for a costly and time-consuming rate proceeding during this timeframe and eliminate the need for the company to carry these costs for an extended period of time," the spokeswoman claimed.

Another component of Yankee Gas' application would establish service quality standards. The plan, which Yankee Gas said is similar to plans already in place for Connecticut's two other gas utilities, would benchmark service quality in five areas — call center performance, gas leak response, service call response, third party damage and estimated billing. Yankee Gas proposed a sliding scale for rewards or penalties based on utility performance above or below the benchmarks.

To encourage customers to use energy efficient appliances, Yankee Gas proposed a pilot "fuel diversity fund." Similar to a conservation charge on electric bills, the proceeds would be used to help offset capital costs of using gas, it said. Yankee Gas estimated collecting approximately \$3.2 million annually via a charge of .0091¢/Ccf. For a typical residential customer that would equate to an extra \$9.10/year, the company said.

Yankee Gas President and Chief Operating Officer Dennis Welch called the rate proposal "a comprehensive blueprint for the future, designed to give Connecticut consumers more energy choices, increase the state's gas supply, support economic development initiatives and opportunities across the state and protect the environment through reduced emissions.

Mountaineer Gas agrees to 16% rate hike, files settlement with West Virginia PSC

Parties representing Mountaineer Gas, the West Virginia Public Service Commission, the state Consumer Advocate's Division, industrial customers and others have agreed to a 16% rate increase for the distributor, according to Billy Gregg, head of the CAD.

The deal represents an increase in both base rates and gas costs for Mountaineer, Gregg said Wednesday. The agreement has been turned over to the PSC, which has until Nov. 1 to act on it.

Under the settlement, Mountaineer's base rate would increase by \$5 million and rates for its gas costs would rise \$23 million. The distributor had been seeking a \$45-mil-

lion increase in gas costs and a \$22-million base rate increase. The deal would allow Mountaineer to increase its base rates by \$1 and the charge for each Mcf used by the same amount, according to the PSC. For a typical household, the monthly bill would increase from \$83.91 to \$97.91.

Mountaineer agreed to reduce its request because of the sharp decline in wholesale gas prices, Gregg said. The increase in base rates stems from increases in employee benefits, he added. A spokesman for Mountaineer declined to comment on the agreement until after the commission rules on the matter.

Gregg noted that the company's return on equity, while not specified in the agreement, would be about 10%. Last year the distributor received a 14% ROE, he said.

Not addressed in the settlement are details regarding service to Mountaineer's transportation customers, Gregg said.

If wholesale gas prices continue to decline, it may be possible for Mountaineer to enter into another rate freeze, he added. The company's previous three-year rate freeze ended in January, and it was estimated to have saved customers more than \$92 million, Gregg said.

In a separate report to the commission, David Ellis, the PSC's utilities director, said distributors should consider hedging their gas costs. "If actual spot prices turn out to be modestly below the hedged price, the strategy cannot be said to have failed" because "gaining a significant price benefit from the hedging strategy should not be the primary goal," according to the report.

"It is the responsibility of utility management to recognize the potential benefits of hedging and to regularly examine its hedging options and expected outcomes. It is poor management to wait for a price disaster to develop hedging knowledge and/or strategies," Ellis asserted in the report.

"Furthermore, a regulatory agency should not be the super-management of a utility, making these hedging decisions on a day to day basis," he said. "A well run utility should not wait for a commission to force it into a serious and studious evaluation of hedging opportunities," noted the report, submitted earlier this month.

It added that a decision not to utilize hedging strategies might not be wrong, but "failure to even consider hedging should be considered as a complete abdication of utility management responsibility."

Groups challenge GPU deal in court; FirstEnergy merger talks continue in N.J.

More groups are appealing to the courts to overturn a recent GPU rate settlement, saying it could harm Pennsylvania ratepayers in the long run. Citizen Power, a consumer group based in Pittsburgh, and the Clean Air Council have filed a petition for review with the Commonwealth Court in Harrisburg, seeking to reverse the Pennsylvania Public Utility Commission's approval of the settlement.

In June, the PUC approved the deal, which deferred GPU's losses in the wholesale power market while keeping retail rates capped. The Mid-Atlantic Power Supply Assn. filed a petition with the Commonwealth Court, asserting

that the agreement punishes customers that shop in the open market by making them pay part of the losses attributable to non-shopping users (*RE*, 13 July, 7).

The rate agreement is contingent on GPU's merger with FirstEnergy, which has proposed buying the company for \$4.7 billion and assuming \$7.4 billion in debt. The PUC and the Federal Energy Regulatory Commission approved the merger, but it faces trouble in New Jersey, where staff of the Board of Public Utilities fears the merger will restrict competition in the state. GPU, FirstEnergy and other parties are in settlement discussions there, which were extended by a BPU administrative law judge. Those talks are scheduled to run until Aug. 13, the ALJ said on Tuesday.

Citizen Power fears the rate impact if the BPU rejects the merger, it told the court. If the merger falls apart, the rate settlement will allow GPU to collect all of its market losses from June 2001 through the end of the year, an amount that could reach \$150 million, according to Citizen Power economist Roger Odisio. After 2001, GPU could continue to recover losses beyond the rate caps, he warned. "No one is talking about what will happen if the merger fails," Odisio told *Retail Energy*.

If the merger does proceed, the settlement allows GPU to recover costs through the "competitive transition charge," which was originally set up to recover the stranded costs stemming from restructuring, the court petition related. Those stranded costs include payments to non-utility generators (NUGs), whose contracts in many cases require GPU to pay them rates above market prices. With the settlement, those NUG payments will be deferred through 2010, and GPU will be able to recover them over a five-year period beginning in 2011, which will cause a rate spike in 2011-2015, Citizen Power said. That will probably require "illegally renegeing on the stranded-cost payments to NUGs," and for that reason the settlement is opposed by the Anthracite Region Independent Power Producers Assn., representing companies that own the NUG plants.

The Clean Air Council of Pennsylvania opposes the merger as well, fearing that FirstEnergy will increase production at its coal plants to supply GPU, thereby aggravating air pollution. In the court petition, the group said the PUC did not consider that impact before it approved the merger.

MARKET SNAPSHOTS

ENERGY SECRETARY SPENCER ABRAHAM last week endorsed distributed generation and net metering as methods to help resolve the nation's energy woes. "California is not the only state in America that faces energy challenges," Abraham said in a speech to the Bay Area Council in San Francisco. California's experience proves that conservation and increased use of renewable energy are not enough to guarantee reliability, Abraham said, adding that if "you don't have enough energy supply, you face the prospect of blackouts. And even if you avoid blackouts, when supply doesn't match demand, you face dramatically higher energy prices and are likely

to encounter lower economic growth.” Asserting that the nation’s energy delivery system is out-of-date, Abraham highlighted the benefits of distributed power. “The concept of distributed energy is broad, but at its essence it means moving from our almost exclusive reliance on big power plants toward smaller sources of power toward a day when consumers can respond to price signals toward smarter factories, buildings and homes. Distributed energy means moving away from a transmission system in which power only flows one way — from a plant to your home — and, instead, contemplates a two-way electricity grid where homes or businesses can sell their surplus power back to the grid.” In such a world, Abraham said customers could generate their own power with a microturbine at home, and reap the benefits of efficiency by conserving and selling excess power into the grid. “Net metering,” he said, “moves away from the idea that there can only be one seller and one buyer in an electricity transaction to a vision in which everyone can be a buyer and a seller of electricity.”

PPL ENERGY PLUS plans to install five small gas-fired generating units at Masonic Homes retirement facility in Elizabethtown, Pa., it said on Friday. The 60-kW microturbines, made by Capstone turbines, are expected to be installed by mid-2002. PPL EnergyPlus did not disclose the cost of the project, but estimated the retirement home will save \$13 million over the next 30 years. That includes savings not just on power, but on heating, since waste from heat from the turbines will be used to pre-heat water in new gas-fired boilers that the company will install to replace old coal-fired boilers. A PPL EnergyPlus subsidiary, McClure Co., will design and construct the project, and PPL will monitor the system, and energy usage, through a building automation system.

SEMPRA ENERGY SOLUTIONS on Tuesday said it will provide the energy infrastructure and related services for a new \$615-million entertainment and retail facility under development in Los Angeles. Sempra’s contract, a 15-year, \$31-million energy services deal, is with TrizecHahn Development Corporation’s Hollywood & Highland, which is developing the facility located on Hollywood Boulevard adjacent to the historic Graumans Chinese Theatre. As a partner in the complex, Sempra Energy Solutions will ensure that the energy infrastructure will operate in a reliable manner, as well as handle commodity procurement when needed, according to Bob Dickerman, president of Sempra Energy Solutions. The complex is scheduled to open in November. “Our partnership with Hollywood & Highland exemplifies the benefits of outsourcing energy services for companies who own large development properties as it provides them with the most value, most efficient infrastructure and most responsive service,” said Dickerman.

LG&E Enertech, an unregulated subsidiary of **LG&E ENERGY**, said it reached an agreement to market energy information services provided by Datapult LP to its commercial

and industrial customers. LG&E Enertech provides energy management services, guaranteeing energy savings that allow customers to finance projects directly from their achieved savings, the company explained. The agreement will allow LG&E Enertech to use Datapult equipment and software to monitor customers’ various energy loads, allowing customers to see their energy profile in 15-minute increments throughout the day, notifying them of energy-wasting conditions and savings opportunities. “When it comes to energy consumption, what a business doesn’t know really can cost them,” said Ron Valentine, director of new business development for LG&E Enertech. “The use of Datapult’s state-of-the-art energy monitoring equipment and software will tremendously advance our abilities to show our customers where to find their savings and problem areas,” Valentine said.

The **U.S. NAVY** and **U.S. POSTAL SERVICE** are seeking proposals from energy suppliers and service companies for facilities in Maine, according to solicitations posted Monday in the Department of Commerce’s Commerce Business. The Postal Service is seeking supplies for 402 facilities in Maine, which use more than 30,000 MWh annually. They are in the territories of Bangor Hydro, Central Maine Power and Maine Public Service. The Postal Service will also consider purchasing gas from suppliers. It expects to sign a single contract, which will run two years, starting Nov. 1, 2001, with three one-year options. Proposals are due Aug. 27. In the second solicitation, the Navy wants to reduce electricity costs at the Portsmouth Naval Shipyard in southeastern Maine, near the naval base at Portsmouth, New Hampshire. The facility has a peak load around 15 MW, and consumes about 54,000 MWh annually at 40% load factor. Its primary supplier is Central Maine Power, but the shipyard has several on-site generating units, including a 5-MW gas turbine that is base-loaded, and two old steam turbines totaling roughly 10 MW, which are used for backup. In the solicitation, the Department of Defense is interested in proposals to manage its electrical supply through purchases, optimizing on-site generation, and employing curtailment strategies. Companies must submit statements of interest by Aug 1.

FROM THE DOCKET

The **NEW YORK PUBLIC SERVICE COMMISSION** has issued final standards and procedures on electronic data interchange (EDI), for communications between distribution utilities and retail marketers. The standards were developed through a collaborative process, and the PSC approved a rough outline in the spring (*RE*, 27 April, 3). Before issuing its final ruling, the PSC took comments from various parties, some of whom asked for more individual protocols. However, the commission insisted on maintaining uniform standards. The PSC is pushing to reach statewide implementation of EDI for all market participants by the end of 2001. Technical documents on the

standards can be obtained by calling (518) 474-2500 and referring to case no. 98-M-0667 and the notice issued July 23. They are also posted on the PSC Website at www.dps.state.ny.us/98m0667.htm.

U.S. Bankruptcy Court Judge Dennis Montali approved **PACIFIC GAS AND ELECTRIC'S** request for a four-month extension of time to file its reorganization plan with the court. In a three-page order, Montali agreed to extend the utility's so-called "exclusivity period" for filing the plan until Dec. 6. PG&E's Creditor's Committee told Montali it would prefer a shorter extension, but said it would "take such action as it deems appropriate" if it determines that the utility "is not proceeding in a satisfactory manner toward formulation, negotiation and filing a plan."

The City of Philadelphia will pay Lehman Brothers at least \$200,000 to conduct a feasibility study on the sale or restructuring of the **PHILADELPHIA GAS WORKS**, City Councilman James Kenney said Monday. Retaining the investment banking company is a positive step, Kenney said, but he remains skeptical of the chances the utility will be sold. Joyce Wilkerson, Mayor John Street's chief of staff, told the council in a memo that, by retaining Lehman Brothers, the city is responding to the Pennsylvania Public Utility Commission's Feb. 21 order to "analyze the potential benefits of the sale of PGW." Wilkerson also said in the memo that the city "is not committed to any particular strategic option." In January Philadelphia City Controller Jonathan Sidel warned that the "uncertain future of the Philadelphia Gas Works threatens the city's budget (*RE*, 26 Jan. 2).

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