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Global Power Report

May 13, 2010

Lawmakers seek to include oil spill provisions in climate legislation as BP slick persists

As a massive crude oil slick continues to taint the Gulf of Mexico, Senate climate change legislation due to be unveiled May 12 would require the Secretary of the Interior to study the impacts of an oil spill in new areas and give directly affected states the authority to stop a leasing proceeding, according to a draft summary of the legislation obtained May 11.

Senators John Kerry, a Massachusetts Democrat, and Joe Lieberman, an Independent Democrat from Connecticut, were set to unveil the much-anticipated bill after press time. The bill would set national greenhouse gas reduction targets of 17% below 2005 levels by 2020 and 83% below by 2050.

The senators, in an effort to attract support; plan to include provisions to bolster domestic offshore oil and natural gas exploration but with what they described as "protections" to address the concerns of many resulting from the BP oil rig explosion and unprecedented spill in the Gulf.

Some senators in coastal states have voiced opposition about moving a bill that would support offshore exploration in the wake of the BP spill but some proponents say the Gulf accident

(continued on page 3)

Varied interests in the energy industry find common ground in financial reform legislation

Rarely do the varied constituencies within the energy industry agree, but they have come together on one issue: financial reform, more specifically, the potential regulation of over-the-counter derivatives.

In a letter sent to US Senate leadership last week, 10 energy industry trade groups — ranging from the American Gas Association and the American Wind Energy Association to the Edison Electric Institute and the Electric Power Supply Association — argued that "a clear commercial end-user exemption is absolutely critical" and urged the Senate to more clearly define the language in the legislation.

In a January report, a similarly diverse group of energy industry associations assessed the costs of being forced to move their hedging arrangements to exchanges instead of using bilateral or OTC arrangements.

"The main issue is that this would move bilateral deals to exchanges, and the parties would have to post collateral," said John Shelk, president and CEO of the Electric Power Supply Association, in an interview this week.

According to the report, OTC Derivatives Reform: Energy Sector Impacts, a competitive power supplier would need to

(continued on page 4)

Tokyo Electric to take a stake in nuclear project with NRG-Toshiba, if DOE guarantee comes through

NRG Energy and Toshiba, partners in the planned 2,700-MW South Texas nuclear expansion project, have found a new investor, but the deal is dependent on securing a loan guarantee from the US government.

On May 10 NRG and Toshiba announced that Tokyo Electric Power Co. would take up to a 500-MW ownership stake in the project.

Nuclear Energy North America, an 88:12 joint venture of NRG and Toshiba, owns 92.35% of the South Texas expansion project. CPS Energy, the municipal utility of San Antonio, owns the remaining 7.65%.

Tepco said that it plans to invest $155 million in the expansion project through its US-based subsidiary for a 10% share of NINA, once the project secures a conditional commitment from DOE for a loan guarantee. The $155 million includes a $30 million option payment to NINA that entitles Tepco to buy an additional 10% share of NINA for an additional $125 million about one year after Tepco's initial investment is made.

(continued on page 2)

INSIDE THIS ISSUE

Tokyo Electric to invest in nuclear project being developed by NRG-Toshiba

... from page 1

Tepco's initial 10% stake in NINA will give it a 9.235% ownership interest in the expansion project, and its second 10% stake will increase that interest to 18.47%, or about 500 MW.

In addition to its planned $280 million investment, "Tepco would also be responsible for 10% of all ... expansion capital costs [associated with NINA's share of the South Texas expansion project] and up to 20% of these costs if the company exercises its option to increase its ownership to 20% of NINA," NRG said in a written statement.

NRG President and CEO David Crane, during an earnings conference call with analysts, said that while Tepco's initial 10% stake in NINA is conditioned upon the expansion project's receipt of a loan-guarantee offer from DOE, there are no additional conditions associated with Tepco's planned second 10% stake, and that he fully expects Tepco's final stake in NINA to be 20%.

But Crane warned that if the Department of Energy does not offer the requested $7 billion loan guarantee to NINA when the department selects the next winner of a guarantee, NRG would suspend all additional investments in the project and explore the possibility of selling its interest in the project.

Crane emphasized, however, that NRG is optimistic that the South Texas expansion project will receive the DOE loan guarantee it and other developers of the project applied for two years ago. If it does, he said, NRG will maintain its currently planned level of spending on the project and seek additional partners beyond Tepco and CPS. Once Tepco has taken a 20% stake in NINA, NRG will own about 64% of the expansion project; NRG has indicated it would like to eventually reduce its stake to about 40%.

Crane said that if the DOE offers a $7 billion loan guarantee the expansion project partners also will explore the possibility of securing "pre-COL funding" for the project from the Japanese government. COL refers to the combined construction and operating license that NINA is seeking from the Nuclear Regulatory Commission.

The South Texas expansion project is among three finalists for the next DOE loan guarantee. The others are the joint plan by Constellation Energy and Electricite de France to add a

Corrections

■ A story in the last issue incorrectly identified the dates by which power plants in and around San Francisco, San Diego and Los Angeles must comply with California's State Water Resources Control Board's recently approved plan to replace once-through cooling systems (*GPR*, 6 May, 20). The correct dates are 2017 for plants in the San Francisco Bay area and San Diego region and 2020 for plants in the Los Angeles area that have contracts with Southern California Edison, not 2015 and 2017 as reported.

■ An article and headline May 3 mischaracterized actions by the California Independent System Operator with respect to its proposal for a transmission planning process to facilitate renewable energy development (*GPR*, 6 May, 20). The ISO has incorporated the renewables-supportive planning process into its broader process addressing all transmission. It has not "discarded" or "scrapped" the renewables-related planning. The proposal formerly named the Renewable Energy Transmission Planning Process, or RETPP, is now called the Revised Transmission Planning Process. "It was always envisioned" that the renewables-related process would be part of the larger comprehensive plan, ISO spokeswoman Stephanie McCorkle said in an e-mail.

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nuclear reactor at the Calvert Cliffs nuclear station in Maryland and the joint plan by South Carolina Electric & Gas and Santee Cooper to add two nuclear reactors at the Summer nuclear station in South Carolina.

DOE's first loan-guarantee offer was made in February to the plan by Georgia Power, Oglethorpe Power and others to add two nuclear units to their jointly owned Vogtle station in Georgia. Vogtle's co-owners are in negotiations with DOE regarding a final agreement on the loan guarantee. That $8.3 billion conditional grant left about $10 billion in the loan guarantee program.

Just last week Energy Secretary Steven Chu said that the DOE needs an additional $9 billion in loan guarantee authority for nuclear power projects before fiscal 2011 to fund the three applicants under consideration (*GPR*, 6 May, 5).

A DOE loan guarantee is considered critical to the South Texas and Calvert Cliffs projects. Each of the projects is "merchant" in nature, so their developers cannot recoup project costs from ratepayers, said Crane, adding that neither project can wait until the next round of DOE loan guarantees being sought by President Barack Obama.

The DOE has requested an additional $36 billion in loan guarantee authority for fiscal 2011 in President Barack Obama's budget request. That request is still under consideration in Congress.

Crane said in response to an analyst's question during the call that he does not expect the DOE to announce that it has decided to split between South Texas and Calvert Cliffs the $10 billion in loan guarantees that it has left to provide under the Energy Policy Act of 2005.

"The people at DOE have worked as hard on this as we have," Crane said. "The last thing DOE wants to do is to make two $5 billion awards [for loan guarantees] and to have both [NINA and Constellation/EdF] announce the next day that they are suspending their projects" after failing to secure the $7 billion loan guarantee offers they need.

Crane noted that the $2 billion difference between a $7 billion loan guarantee and a $5 billion one would represent "an enormous amount of equity to raise."

NINA President and CEO Steve Winn said from Tokyo in an interview that it is possible that Congress may agree to expand the loan-guarantee total under the Energy Policy Act by another $4 billion, or enough to accommodate $7 billion loan guarantees for both the South Texas and Calvert Cliffs projects.

Winn also said he anticipates that about 80% of the South Texas expansion project's estimated $13 billion cost — $10 billion in "overnight" costs plus $3 billion in financing — will be paid for with debt, "including about $7 billion from US and $3.5 billion from Japan." The remaining $2.5 billion will come from equity investments, Winn said, noting that NINA and CPS already have invested a total of about $800 million, leaving about $1.7 billion in additional equity investment to come.

Winn also dismissed concerns that currently low natural gas prices are significantly reducing the value of power purchase agreements that NINA is lining up with Texas power buyers. These buyers are taking a very long-term view of where gas prices may be heading, he said, adding that many buyers are now largely dependent on gas-fired generation and are seeking to diversify their fuel mixes.

NRG said that if the expansion project receives a COL from NRC and a loan guarantee commitment from DOE "in a timely fashion," construction is expected to begin in 2012, with one unit coming online in 2016 and the other in 2017. — *Housley Carr*

Quote of the week

"Well, I haven't died, so why should I buy life insurance?" — Vincent Duane, vice president and general counsel at PJM Interconnection, characterizing the arguments of opponents to a proposal that would make regional transmission organizations a legal counterparty in energy transactions (see story, page 13).

Lawmakers want to include provisions for oil spills in climate bill ... from page 1

should stir Congress to act this year.

The 21-page draft summary of the bill says new revenue sharing from the Outer Continental Shelf areas in certain coastal states would be authorized where leases were previously withdrawn. The summary said "37.5% of revenues are directed to states" and 12.5% of revenues would go toward state and federal programs under the Land and Water Conservation Fund.

In addition, the interior secretary would be required to study the economic and environmental impacts of "any potential oil spill" in areas that newly become available for revenue sharing. Based on the outcomes of such a study, "directly impacted states may prevent leasing from proceeding," the draft summary said.

A state also would be allowed to enact a low prohibiting leasing within 75 miles of its coastline.

Carbon dioxide capture and sequestration would be the subject of studies within the administration to find ways to eliminate barriers to commercializing the technology for coal-fired power plants. A fee collected from fossil-fuel based electricity consumers would be used to accelerate the development of the technology for power plants.

The bill would also establish performance standards for coal-fired power plants permitted in 2009 and thereafter.

The bill seeks to tackle emissions from electric power generation through the use of a greenhouse gas market that restricts participation to "regulated carbon market participants and compliance entities" registered with the Commodity Futures Trading Commission.

The bill would give the CFTC jurisdiction over the trading in GHG markets and seek to amend the Commodity Exchange Act to include greenhouse gas instruments in its provisions prohibiting market fraud and manipulation.

The Environmental Protection Agency would distribute emission allowances each year to local distribution companies, or regulated electric utilities, between 2013 and 2029. The summary draft did not say how many allowances would be distributed to the electric power sector.

These tradable allowances would be used "exclusively for the benefit of the ratepayers," the draft summary said. "These allowances may not be used to support electricity sales or deliveries to individuals or entities other than those ratepayers," the summary said.

The senators also include provisions they said would ensure "regulatory predictability" of GHG emissions. They include precluding EPA from using the existing Clean Air Act to issue "new source performance standards" for entities that emit GHGs and from using its "new source review" provisions on emitting stationary sources initially permitted or modified after January 1, 2009.

The bill prohibits GHGs from being regulated as hazardous air pollutants.

For nuclear energy, the bill would increase the "innovative technology loan guarantee program" to $54 billion. It also would provide regulatory risk insurance for up to 12 reactors.

In addition, the nuclear energy industry would receive a half-dozen tax breaks including those to reduce the accelerated depreciation period for new nuclear plants to five years and a 10% investment tax credit for new facilities.

Nuclear power plants would be eligible for an advanced energy project credit and public-private partnerships for advanced nuclear power also would be allowed. Tax-exempt bonds could be used for public-private partnerships to develop advanced nuclear power facilities. Public power and cooperatives would be eligible for grants in lieu of tax credits for qualified nuclear power projects.

To streamline the permitting process for new nuclear reactors, the bill asks the Nuclear Regulatory Commission to report to Congress on ways to expedite the licensing process for new nuclear reactors. The bill also would amend the Atomic Energy Act of 1954 to remove the requirement for an administrative hearing on non-contested issues prior to granting approvals for construction and operating licenses, the draft summary said. — *Cathy Cash*

Varied interests in energy industry find common ground in financial reform ... from page 1

provide $1 billion to $2 billion in cash margin to its counterparties. The result, the report says, is that the companies would either not hedge or the increased collateral requirements would siphon capital away from needed infrastructure development.

Other constituents within the industry have different specific concerns, but they all make similar points. A regulated electric utility would require $300 million to $400 million in cash margin, "directly jeopardizing its investments in efficiency, a 'smart' grid and transmission for renewable power," according to the energy impacts report.

Public power utilities say they would lose access to tax-exempt financing for the prepayment of long-term natural gas and electricity supply contracts.

In the gas and oil sector, the report claims, independent exploration and production companies would have $700 million less cash to invest in natural gas production, equivalent to the elimination of 240 wells in the Fayetteville shale and equal to an economic loss of $1.9 billion.

Currently energy firms that use bilateral hedging arrangements use a variety of alternatives to cash collateral, including letters of credit and liens on assets such as power plants.

"We are getting caught up in this political tsunami that anything that is a derivative is a bad thing," said Shelk.

Right now, it looks like the energy industry's unified lobbying efforts are working. In the House version of the financial reform bill, H.R. 3795, "We got pretty much what we wanted," said Shelk.

What the energy industry wants are exemptions that exclude commercial end-users and clear language that would ensure that a commercial entity is not inadvertently misclassified as a financial institution or, more specifically, as a "swap dealer" or a "major swap participant."

The financial reform legislation now in the Senate, S. 3217, is similar from the House version and includes the exemptions that the energy industry wants, but that makes the definitions more important, said Dan Dolan, vice president of policy research and communications at EPSA. "There are good exceptions, we just need to make sure we can use them," he said.

The energy industry wants to clarify the language defining a "swap dealer" as an entity that buys or sells swaps as its primary business as a market maker or dealer, not just an entity that buys or sell swaps.

And under the definition of "major swap participant" the energy industry is asking the lawmakers to define "substantial position" as one that could "significantly impact" the US financial system. They also want "substantial position" not to be defined as an amount lower than the hedge exemption granted to an entity.

The energy industry also is urging lawmakers to resolve potential jurisdictional conflicts. In short, instruments now regulated by the Federal Energy Regulatory Commission, such as the products and services of regional wholesale power markets, should remain under FERC jurisdiction and not be moved under the jurisdiction of the Commodity Futures Trading Commission.

Just last week Senator Jeff Bingaman, chairman of the Energy and Natural Resources Committee, proposed an amendment to the Senate financial reform bill that would preserve FERC's jurisdiction over derivatives used by regional transmission organizations and independent system operators.

On May 11 a group that includes the American Gas Association, AWEA, the California ISO, the Edison Electric Institute, EPSA and the PJM Interconnection sent a letter to Bingaman and other Senate leaders supporting the amendment. However, a group of energy exchanges and futures industry advocates on the same day said they "strongly oppose" the proposed amendment because it would undermine the CFTC's authority over natural gas and electricity futures, swaps and options markets.

For now, it looks like the energy industry may get what it wants. The exemption language in the House version of the financial reform bill has made it into the Senate's version of the bill, but there is still a broader question that could pose significant problems.

The energy industry could get everything it wants, but the law could be very tough on financial institutions, and they may decide not to participate in commodity hedges.

"That is a very real concern," said Dolan. "It is a balancing act." He said that EPSA is being very careful to let lawmakers know that they are not doing the bidding of the banks. But at the same time, "We need the banks; we need to continue to work with them," said Dolan. "We acknowledge that there needs to be increased oversight of banks, but we do not want them knocked out of the business."

If that were to happen, who would step into the breach?

"We haven't heard definitively who that would be or what the cost would be," said Dolan, but he said that some EPSA members are thinking about that.

But no matter what shape the final legislation takes, the energy industry likely will still have years of work ahead of it. The implementing regulations for the financial reform legislation will likely be drawn up by the CFTC.

"When I first got this job I thought I would be spending a lot of time at FERC. I never thought I might be spending a lot of time at the CFTC," said Shelk. *— Peter Maloney*

COMPANY NEWS

RBS Sempra prepares to announce winner of new bidding round for North American assets

RBS Sempra Commodities, which is selling its North American natural gas and power trading books, as well as its retail electricity unit, is expected to announce the winner, or winners, of a second round of bid offers for the assets within four to six weeks, according to Sempra Energy officials.

A second round of bid offers was to have taken place over the past few days, but RBS Sempra Commodities spokesman Mike Geller said May 11 he was unable to comment on any part of the bid process.

During an earnings conference call last week, Sempra Energy CEO Donald Felsinger said the company expects "parts of the business to see some pretty robust bids."

Felsinger was asked if the final sale of the joint venture assets were being affected, or delayed, by "turmoil" that financial players are facing in the form of restrictions on their activities that are under discussion in the Congress as a financial reform bill is being hammered out.

Felsinger said, "No, it is not."

Felsinger said that the company expects to announce the winning bids within four to six weeks, and to close the deals by July or August.

The names of a number of companies that are believed to be interested in the assets have emerged, but neither the Royal Bank of Scotland nor Sempra Energy, who formed the joint venture in April 2008, have been willing to identify the interested companies.

Such names as Morgan Stanley, Goldman Sachs and even Shell, have popped up.

On May 11, Goldman Sachs confirmed that it was involved in a separate acquisition. It reached an agreement May 5 to buy the natural gas trading book of Calgary, Canada-based trading firm Nexen, which has been on the block since last July. Goldman did not acquire Nexen's power trading book in the deal, however.

The Swiss-based oil trader, Vitol, has been linked over the past few weeks to the possible purchase of RBS Sempra's North American natural gas and power trading operations that are based in Stamford, Connecticut.

Vitol, whose US operations are based in Houston, has not denied its interest in RBS Sempra's two large trading books, but the big international trading house has not confirmed its interest, either.

According to Platts, RBS Sempra Commodities had 5.05% of the wholesale power sales market in the US in the fourth quarter of 2009, ranking it third behind Exelon and Morgan Stanley.

Executives from Sempra Energy have said repeatedly that the joint venture partner is not interested in retaining ownership of either the North American power and gas trading business nor the retail unit past the end of this year, due to the high cost of posting collateral.

Sempra executives have said that the retail business could be sold separately, or along with the trading books.

On February 16, the RBS Sempra Commodities joint venture announced that it had sold roughly 45% of its assets to a unit of JP Morgan Chase, called JP Morgan Ventures, for approximately $1.7 billion. *— Jeffrey Ryser*

FINANCE

Falling power prices take their toll on merchants as they report lower EBITDA on tighter margins

Falling power prices took their toll on merchant generators this quarter, lowering cash flows even though some generators were able to book gains in regulatory earnings because of hedging arrangements.

Dynegy's EBITDA in the first quarter was $152 million, down 24% from $199 million in first-quarter 2009. The company attributed the decline mainly to reduced contributions from hedging activities and reduced spark spreads.

On a GAAP basis, Dynegy reported first-quarter income of $145 million compared with a loss of $355 million in first-quarter 2009. Dynegy's revenues were $858 million, down from $904 million in first-quarter 2009.

Mirant also saw a decline in EBITDA in the quarter, to $162 million from $195 million in first-quarter 2009. Mirant attributed the decline mainly to "lower realized value of hedges, lower energy gross margins from Northeast generation and lower net gains from sales of emissions allowances."

Its GAAP earnings, however, rose to $407 million in the first quarter, up from $380 million in the first quarter of last year. Mirant said it that $352 million of the $407 million was tied to unrealized gains, principally from hedges.

Calpine's adjusted EBITDA for the first quarter was $282 million, a decline from $331 million in first-quarter 2009.

"The year-over-year decline was primarily due to a $74 million decrease in commodity margin from $529 million in the first quarter of 2009 to $455 million in the first quarter of 2010," the company said.

Calpine said the commodity margin decline was attributable to the expiration of legacy contracts in California at the end of 2009, and lower average hedge margins in the first quarter of 2010 compared with 2009, resulting from relatively lower hedge prices in 2010 as compared to hedge prices for 2009.

The declines were partially offset by revenue from the company's 608-MW Otay Mesa plant near San Diego that began operation in October 2009.

NRG Energy managed to post a gain, with adjusted EBITDA of $601 million, up from $477 million in first-quarter 2009. The company said the increase partially reflects its May 2009 purchase of Reliant Energy.

Reliant added $190 million of adjusted EBITDA in the quarter, which saw sales driven by colder than normal temperatures. Reliant sold 11 million MWh, generating $1.25 billion in revenue.

In Texas, however, NRG's adjusted EBITDA fell to $272 million from $320 million a year ago. Margins fell on lower hedged prices, a decline in nuclear generation and higher fuel costs at two coal plants.

NRG also suffered EBITDA losses in its Northeast and South Central regions. Its western operations, however, saw adjusted EBITDA jump to $10 million from $1 million a year ago on higher power prices.

A decline in merchant earnings also hurt **Ameren**, which reported lower earnings despite an 8.8% jump in power sales.

The St. Louis-based electric and natural gas utility reported income of $106 million, down from $145 million a year ago, and attributed the decline to lower merchant generation margins, higher depreciation expenses and financing costs, as well as an increased average number of common shares outstanding.

Ameren said it plans to slash expenditures at its merchant segment where quarterly income plunged to $44 million from $93 million a year ago. The company announced a further $435 million reduction to previously planned 2010 to 2014 merchant generation capital expenditures. The action is part of the company's ongoing effort to ensure that our merchant generation business remains well positioned to weather low power prices and benefit from an expected power price recovery.

Last month Ameren cut 75 positions at its merchant business, which followed 135 staff cuts last year. Although Ameren said it has no plans to shut any power plants, with low capacity and energy prices in the Midwest region, the company said it and other companies will likely be looking at their least-efficient plants for possible temporary mothballing.

Allegheny Energy said income from its merchant generation segment fell 37.4% to $45.5 million from $79.9 million in first-quarter 2009 because of lower market prices, higher fuel prices and higher interest and depreciation from placing a scrubber in service. The company said the negative factors were partially offset by power hedges, increased capacity revenue and lower income taxes.

PSEG Power, the merchant arm of Public Service Enterprise Group, reported operating earnings of $298 million in the first quarter compared with $352 million in first-quarter 2009. The company said its earnings were affected by weak power prices that more than offset a 7% increase in sales volumes.

The company said it expects to see a shift in earnings away from the merchant side of the business to the regulatory side. There is a surplus supply in most of the company's merchant markets, but additional earnings can be achieved on the regulatory side without pushing up customers' bills, PSEG said.

And **AES** Corp. posted a $187 million profit in the first quarter of 2010, a decline of just over 14% compared with earnings of $218 million in first-quarter 2009.

The decrease came despite an improved first quarter for the company's North American operations, where first-quarter gross margin rose to $134 million from $120 million.

And the company's North American utilities unit posted a $76 million gross margin in the quarter, compared with margin of $70 million in first-quarter 2009.

These improvements came despite what the company said were "unfavorable energy prices and lower volumes in New York."

Overall the company's gross margin for the quarter rose to $1 billion from $856 million in the year-ago period. AES said its Filipino generation and Brazilian utility segments were major factors in the increase in margin. *— Housley Carr, Ethan Howland, Mary Powers and Staff Reports*

Fitch Ratings upgrades its NRG Energy rating to B+, citing lower risk, balance sheet strength

Fitch Ratings last week upgraded NRG Energy's issuer default rating from B to B+, its fourth highest speculative grade, citing balance sheet strength and a focus on maintaining revenue stability and reduced business risk after the acquisition of Reliant Energy's retail electric business in May 2009.

The "ratings also consider the challenging competitive generation environment Fitch expects for 2010-11, tempered by NRG's steps to improve its balance sheet and hedge a significant portion of wholesale generation and commodity price exposure," added Fitch's Peter Molica and Roshan Bains.

Fitch also took NRG off Rating Watch Evolving. The outlook is now stable, due to NRG's substantially hedged baseload fleet and successful incorporation and operation of Reliant, which should ensure a predictable earnings and cash flow stream over the next two years, it said.

But Fitch warned the ratings and outlook could be pressured by federal carbon dioxide regulation and/or legislation. In addition, NRG is exposed to proposed financial regulatory legislation that would require derivatives positions to be cash collateralized, with a significant impact on NRG's liquidity if end-users do not receive exemptions.

A sustained drop in natural gas prices, pursuit of leveraged growth activities, and more stringent-than-anticipated environmental or derivatives trading regulations could have the same effect, Fitch said. — *Paul Carlsen*

ASIA/PACIFIC RIM

Indonesia's PLN to invite bids for project, 600-MW fired by coal in south Sumatra

Indonesian state-owned utility Perusahaan Listrik Negara plans to invite bids from private and foreign investors to build a 600-MW, $750 million coal-fired plant in the south Sumatra.

"This is an independent power producer project and the plant will be under a build, own and transfer program," PLN said.

The plant would be located close to a mine in south Sumatra to reduce the fuel transport costs. The plant is likely to be operational by 2014. The developer has to sign a 25-year power purchase agreement with PLN. A maximum of four investor groups can be part of a consortium bidding for the project. PLN did not provide further details on the proposed tender.

The project is part of PLN's second 10,000-MW fast track program under which the government has allowed both PLN and private companies to develop the projects. Of the planned capacity, nearly 40% would be generated from geothermal plants, 12% from hydropower plants, 14% from natural gas-fired plants and the rest from coal-fired plants. Of the total capacity planned, approximately 5,000 MW would be built in the Java and Bali islands with the remaining capacity built on other islands. The plants would be built between 2010 and 2014, and the entire program would require an investment of $10 billion.

PLN said four more coal-fired projects totaling 1,400 MW were planned near coal mines in south Sumatra. PLN did not say when these projects would be tendered.

The first 10,000-MW fast track program was announced in 2007 and PLN is the sole developer. Under this program, PLN is building 10 coal-fired plants in Java and 23 coal-fired plants outside of Java at a total investment of $8 billion. At present, PLN owns power plants totaling 24,000 MW. — *S. Anuradha*

AES subsidiary signs PPA with EVN for 1.2-GW coal-fired plant in Vietnam

AES VCM Mong Duong Power Co., a subsidiary of AES Corp., last week signed a power purchase agreement with state-owned Electricity of Vietnam for the 1,200-MW Mong Duong-II coal-fired project.

In a news release AES said the PPA has a term of 25 years, but the company did not provide details on the tariff.

"Under the PPA, capacity payments and the majority of operations and maintenance payments will be denominated and paid in US dollars. The PPA allows for a fuel cost pass through, which will be denominated in local currency," AES said.

AES VCM has also signed a 25-year agreement with Vietnam National Coal-Mineral Industries Group (Vinacomin) to supply locally sourced coal to the plant which would be located in the Quang Ninh Province.

AES VCM plans to sign the engineering-procurement-construction contract for the project shortly and achieve financial closure in the first half of 2011. AES VCM owns 90% of the project. Vinacomin owns 10%. AES VCM plans to invest $400 million as equity in the project, which is scheduled to start operation in 2014. The company did not reveal the project costs.

AES Chief Executive Officer Paul Hanrahan said, "Expanding in Vietnam is a key part of our strategy of pursuing new opportunities in Asia where demand for electricity is projected to outpace much of the rest of the world."

AES said at present 9%, which translates into 3,725 MW, of its global portfolio and 60%, around 22,850 MW, of its development pipeline is in Asia.

AES said demand for electricity in Vietnam is likely to grow at 15% annually over the next decade compared with 13.5% annual growth over the last five years.

The Mong Duong project is one of the key projects in Vietnam which has been struggling to develop new power plants amidst severe power shortage.

Lack of a transparent pricing policy and concerns over EVN's financial risks have prevented foreign investors from investing heavily in the Vietnamese power sector. EVN owns power plants totaling 11,300 MW. — *S. Anuradha*

Hong Kong's CLP plans to restructure China coal-fired business and focus on renewables

Hong Kong-based CLP Holdings Ltd. plans to restructure its coal-fired assets in China and concentrate on the renewable energy sector in the country. In the first step towards the restructuring, CLP Power China Ltd., a unit CLP Holdings, plans to sell its 70% stake in the 600-MW Anshun-II plant in Guizhou, China to state-owned China Guodian Corp. for $109 million.

"In line with our group-wide policy of reducing the carbon intensity of our generation portfolio, we aim to rebalance our project portfolio in the Mainland from one centered on coal-fired generation to one which prioritizes low carbon emissions. We intend to consolidate and rationalize our asset ownership and structure for our coal-fired projects, and to continue the pursuit of clean and renewable energy sources in the Mainland, including wind energy, hydropower and nuclear energy," Michael Kadoorie, chairman of CLP Holdings said.

CLP owns power plants totaling 4,600 MW in mainland China of which 900 MW are from renewable energy plants. Its total installed capacity is 17,000 MW. China Guodian is the third largest state-owned power generators in China with an installed capacity of 80,000 MW.

Commenting on the sale of the Anshun-II project, Andrew Brandler, chief executive officer of CLP Holdings said, "The Anshun-II project had a complicated and suboptimal ownership and operating structure, and we took this opportunity to divest our stake in order to rationalize and consolidate our asset ownership in coal-fired projects in the Mainland."

The other shareholders of the Anshun-II plant are China Huadian Corp. with an 18% stake and the Guizhou Development and Investment Co. with a 12% stake. Developed on a build-own-operate basis, Anshun-II was financed in 2002 and commissioned in 2004. It was CLP's first majority owned coal-fired power project in mainland China. CLP said that while the plant operated profitably in 2009 because of high utilization rates and low coal prices its efficiency could not be maximized because it shared common facilities with the Anshun-1 plant that is owned by the provincial government of Guizhou.

Analysts said the sale of the Anshun-II plant was not surprising because the rising prices of coal are likely to affect the profitability of coal-fired plants in China. The sale of the Anshun-II plant is not likely to affect CLP Holdings' financial profile because the earnings from the plant were just $20 million in 2009. During the same year, CLP Holdings' total earnings were $1.05 billion while earnings from China were $51 million.

Commenting on its other coal-fired assets in China, CLP Holdings said the utilization rates improved at the 1,260-MW Fangchenggang plant in Guangxi Province after a slump in the first half of 2009. CLP Holdings said the upward trend in utilization rates is sustainable in 2010.

CLP Holdings said the 2,000-MW Suizhong-II coal-fired plant in Liaoning Province is likely to begin operations in the second half of 2010.

On the renewable energy front, CLP Holdings plans to build a 48-MW wind farm at Penglai in 2010. It also plans to commission a 330-MW hydropower plant in Sichuan Province in 2011. — *S. Anuradha*

India's Tata Power plans 500 MW of wind and 300 MW of solar capacity over five years

India's Tata Power Co. said it plans to develop wind power projects totaling 500 MW and solar power projects totaling 300 MW over the next five years.

Tata Power currently owns wind farms totaling 160 MW and has no solar power facilities. Its total installed capacity is 2,900 MW of which coal-fired and oil-fired plants generate 2,269 MW and hydropower plants 471 MW.

An official at Tata Power said the company was focusing on these sectors to take advantage of the national thrust on renewable energy. The company was also building the renewable energy projects to reduce the carbon impact of its large coal-fired projects, he said.

In 2009, the Indian government announced the National Solar Mission under which it plans to give tariff and tax incentives to solar power developers. It also announced financial incentives to promote wind power generation.

Tata Power said its new wind power projects would be in the states of Maharashtra, Tamil Nadu and Rajasthan. The company is also developing a 3-MW grid-connected solar power plant in Mulshi in western India. Tata Power did not provide further details on these projects.

Tata Power said over the next five years India has the potential to develop solar power projects totaling 2,000 MW, 4,850 MW of wind power projects, 1,500 MW of small hydropower projects and 1,600 MW of biomass projects.

The company's carbon emissions are expected to rise sharply after the implementation of the large coal-fired projects. Tata Power is currently developing the $4 billion, 4,000-MW Mundra and the $1.12 billion, 1,050-MW Maithon coal-fired projects. The Mundra power plant is likely to be commissioned in stages between 2011 and 2012 while the Maithon plant would be commissioned between 2010 and 2011. — *S. Anuradha*

EUROPE

Polish generator PGE obtains EC financing for carbon capture project at Belchatow plant

Poland's largest power company, Polska Grupa Energetyczna, said May 7 it has signed a deal with the European Commission to finance a carbon capture and storage project at its Elektrownia Belchatow plant in central Poland.

In a statement, PGE said it would obtain a €180 million ($233 million) grant under the EC's European Economic Recovery Plan.

PGE is planning to build a CCS installation on its new 858-MW block at Elektrownia Belchatow. The block is scheduled to be commissioned in October.

The company said the installation will be able to sequester 1.8 million metric tons a year of carbon dioxide. The investment will be implemented between 2010 and 2015, PGE said, with the grant paid in annual installments.

The lignite-fired Elektrownia Belchatow plant, with installed capacity of 4,450 MW, is the country's largest power plant and represents 15% of Poland's total installed capacity.

In other news, Poland's dominant gas company PGNiG said May 7 it had signed a deal with the country's second largest power group Tauron Polska Energia to build Poland's largest gas-fired combined heat and power plant at the site of Tauron's Elektrownia Stalowa Wola plant in southeast Poland.

Each company plans to take a 50% stake in the plant, which will have installed electric capacity of 400 MW and 265 MW of thermal capacity. Planned annual production is 3.1 TWh of power and 1.8 PJ of heat.

In September last year PGNiG set up PGNiG Energia to move into the power generation and sales sector.

The company is targeting equity stakes in gas-fired generation projects to allow it to sell electricity to industrial and retail customers because PGNiG can increase its margins in Poland's deregulated wholesale power market.

PGNiG will supply the plant with 550 million cubic meters/year of gas and is interested in offtaking half of the block's production for its own power needs.

The plant is scheduled to be commissioned in mid-2014.

PGNiG said it expects to obtain a grid connection permit for the project later this year and select a general contractor to build the plant in mid-2011. It will cost an estimated 1.9 billion Polish zloty ($580 million).

PGNiG said at least 50% of the costs would be financed through credit. Tauron's coal-fired Elektrownia Stalowa Wola plant currently has installed capacity of 341 MWe and 341 MWt. — *Adam Easton*

European/Middle Eastern briefs

■ Danish energy company **Dong Energy** has applied to build a 300-MW biomass-fired station on Humberside, England, according to a May 6 note in state journal the *London Gazette*.

The applicant is seeking a development consent order under section 37 of the Planning Act to build and operate a biomass power plant "capable of generating just under 300 MW" near Queen Elizabeth Dock on the north shore of the River Humber and within the port estate of Associated British Ports.

Several UK biomass projects have been proposed at just below 300-MW. This is the threshold above which industrial installations must prove carbon capture readiness.

■ France's **GDF Suez** has bought combined heat and power company Utilicom from the IDEX group to form the UK's largest district energy firm, it said last week.

Utilicom is a group of district energy companies operating in the Southampton and Birmingham areas of England.

The new company will be formed from Utilicom and GDF Suez' existing UK Cofely business, and will be called Cofely District Energy.

It will generate 35 MW of low carbon power output, operate 245 MW of boiler plant capacity, 74 MW of cooling systems, and manage 50 kilometers of district heating and cooling networks.

Cofely operates more than 110 district heating and cooling systems in Europe, including the cities of Amsterdam, Barcelona, Lisbon, Monaco and Paris.

■ South Korea's **Daewoo** Corp. has won a tender to build a 440-MW plant at Mishor Rotem in Israel for OC Power Ltd., which is owned jointly by Israel Corp. and Veolia Environment. Japan's Mitsubishi Power Systems will supply the gas turbines. The contracts are worth $470 million.

Construction is due to begin later this year and is scheduled for completion in December 2012.

■ Israel's National Infrastructure Committee has approved plans for a pumped storage power plant at Maaleh Gilboa in the Galilee region. The 300-MW Maaleh Gilboa plant will be built by **PSP**, a joint venture of Ortam Sahar Ltd., Electra Ltd. and private Israeli businessman Raanan Alony.

NORTH AMERICA

PROJECTS

Mississippi Power objects to conditions on permit for 582-MW IGCC project

Mississippi Power has asked the Mississippi Public Service Commission to reconsider its April 29 decision to permit the utility to build a proposed 582-MW integrated gasification combined-cycle plant only if it agreed to significant conditions.

Mississippi Power, a Southern Company subsidiary, said in the filing that "many of the findings made by the commission in its order are not supported by the overwhelming evidence in the record and, if not modified, would be tantamount to changing the burden of proof for utilities in certificate proceedings contrary to the well established requirements of" Mississippi law and PSC regulations.

The utility said that it has reviewed the PSC's order in detail and "determined that it will be unable to move forward with the project under [the proposed] conditions."

More specifically, Mississippi Power said that the PSC's proposed $2.4 billion capital cost cap for the proposed Kemper County IGCC plant is "too low to obtain financing and imposed too much risk" on the utility. "The commission's proposed cap creates too much cost recovery uncertainty, and in today's tight financial markets, lenders want to know that they will be repaid."

The utility also said that "no prudent company" could agree to the PSC's proposed operational cost cap, which Mississippi Power called "vague [and] undefined." Further, it said that the PSC "failed to provide any decision" on whether Mississippi Power could receive early cost recovery for the IGCC project "despite the company's consistent message that full [construction work in progress] treatment is essential" in securing project financing.

Mississippi Power instead proposed a capital cost rate cap of $2.88 billion, or 20% higher than both the utility's $2.4 billion cost estimate and the PSC's proposed cap; in the weeks prior to the PSC's order, Mississippi Power had proposed a cost cap of $3.2 billion, or 33% higher than its cost estimate.

The utility also proposed that the PSC authorize early cost recovery, and asked the commission to issue a ruling on its request "no later than May 28." Failing that, it asked the PSC to make its April 29 order final — rather than conditional — so that Mississippi Power could appeal the ruling to the state's Supreme Court.

In its 2-1 ruling nearly two weeks ago, the PSC said that the Kemper project's "uncertainties and risks, relative to their potential benefits, are too high in number and magnitude to warrant a finding of 'public convenience and necessity.' The commission gave Mississippi Power 20 days to accept its conditions. — *Housley Carr*

Environmental groups file joint petitions challenging LS Power's Georgia coal project

The Sierra Club and Friends of the Chattahoochee on May 10 filed joint court petitions challenging aspects of Georgia Environmental Protection Division air permit for LS Power's proposed 1,200-MW Longleaf coal project in Early County, said GreenLaw, an Atlanta-based environmental law group that made the filings on their behalf.

The EPD last month approved amendments to the air permit it had previously granted the Longleaf project. One amendment reduced the project's permissible mercury emissions, and the other extended to October 1, 2011, the date by which the project must be under construction, and to December 31, 2015, the date by which it must begin commercial operation.

In the newly filed petitions, GreenLaw, Sierra Club and

Friends of the Chattachoochee assert that EPD incorrectly classifies the Longleaf project as a "synthetic minor" source of hazardous air pollution, and thereby incorrectly freed the project from a requirement that it employ maximum achievable control technology. Also, the groups assert that by extending the deadlines by which construction and commercial operation of the project must begin, EPD would allow the plant to be built with outdated technology.

Similarly, GreenLaw on May 10 also made filings for the Sierra Club and several other groups challenging EPD decisions on air and water permits for an 850-MW coal project in Washington County proposed by Power4Georgians, a group of electric cooperatives.

LS Power Project Manager Mike Vogt said that the Longleaf project holds a final air permit "that has been upheld through litigation" initiated by Sierra Club and others, and that LS Power is confident that the permit amendments recently approved by EPD will be reaffirmed as well.

"I think the strategy [of project opponents] is to litigate everything, whether it has merit or not," Vogt said, adding that suing to try to block the project "is, of course, their right." He said that LS Power hopes to be able to begin construction of Longleaf as soon as late 2010; if it can, the plant would likely come online in 2015. — *Housley Carr*

CONTRACTS

National Grid signs contract to purchase half the output of Cape Wind at 20 cents/kWh

National Grid has signed a long-term contract to purchase half of the output of Cape Wind's proposed 468-MW wind farm off the coast of Nantucket beginning in 2013, Tom King, National Grid's president, said last week.

Negotiations were completed May 6 and the contract and full details of the agreement filed with the Massachusetts Department of Public Utilities May 10, King said.

National Grid will pay 20.7 cents/kWh for the energy and renewable energy credits associated with the output, King said. The price also includes transmission costs, he said. The price includes existing federal tax incentives and would increase 3.5% a year during the term of the contract, King said.

The contract is expected to cost an average customer using 500 kWh an additional $1.59 a month, although that could decrease if the cost of fuel for other sources of generation increases, King said.

The power from Cape Wind will represent less than 3.5% of National Grid's electric load in Massachusetts and will more than meet the 3% renewable energy long-term contracting requirement of the state's Green Communities Act, King said.

The average output from the project will be 91 MW, Jim Gordon, Cape Wind's president, said.

The agreement with National Grid will help Cape Wind get the financing and equity in place to build the project, Gordon said.

Cape Wind also is negotiating with other utilities, retail marketers and for direct retail sales for the purchase of the remainder of the wind farm's output, he said. Gordon expects to have contracts in place within the next few months so the entire project can be built out at one time rather than in phases. The project should be completed by the end of 2012.

"We're convinced we will sell the rest. Now that we have an anchor customer we have begun negotiations with the banking community [for financing]," he said.

Gordon would not give the expected cost to build the project because of ongoing negotiations with offshore marine construction companies.

Ian Bowles, Massachusetts secretary of energy and environmental affairs, said last week that he is satisfied that the contract has met his two earlier demands. Bowles had warned the companies that the state expected a power purchase agreement at a substantially lower price than National Grid negotiated for power from a project off the coast of Rhode Island. Bowles said the 24.4 cent/kWh price for that project did not include transmission, making the Cape Wind contract about half the price per kWh. The companies also agreed that any federal tax credits or other benefits would be passed along to ratepayers. "I'm told the contract reflects that," he said.

Bowles also said the state is working with the federal Department of the Interior on a request for interest for developing additional offshore wind generation south of Nantucket and Martha's Vineyard. "Europe is 20 years ahead of us," Bowles said, noting that a 34,000-MW solicitation for offshore wind generation had recently been issued in Europe. "That's 100 times the size of Cape Wind," he said.

The Department of the Interior approved the construction of the Cape Wind project in late April. It was the agency's first approval for the development of an offshore wind farm. Projects off the coast of Delaware and New Jersey are pending.

Delmarva Power has signed a power purchase agreement with Bluewater Wind for 200 MW at a 2013 price of 14.21 cents/kWh. The Bluewater price also includes transmission costs, and it has a 2.5% annual escalator. The Bluewater project would be located off the coast of Delaware. — *Mary Powers*

BioEnergy, Hoosier Energy sign PPA for 27-MW biomass plant in Indiana

BioEnergy Development Co. said it has signed a 20-year power purchase agreement with Hoosier Energy for the sale of the entire 27-MW output of a biomass plant proposed for Clay County, Indiana.

The plant will burn wood waste previously provided to a paper plant in Terre Haute, Indiana. That plant closed in 2007 and a Purdue University study commissioned by the Indiana Energy Department identified "green" energy production as the highest and best use of the wood waste.

In an early May filing with the Indiana Utility Regulatory Commission, BioEnergy Development said the power plant, called BioEnergy Power LLC, will burn no other fuel except wood waste. The cost of the plant was not disclosed.

In addition to its original 20-year period, the PPA with Hoosier, a Bloomington-based generation and transmission co-op, provides for three five-year renewal options that can be exercised by either party.

Hoosier also has the option to purchase the plant at any time during the PPA, and it will own all renewable energy credits generated by the facility.

Peter Hatton, a BioEnergy Development attorney, told the commission that construction is scheduled to begin in the fall of 2010, with the plant in commercial operation a year later.
— *Bob Matyi*

SOLICITATIONS

Seattle utility plans to sell third-party rights to capacity on Pacific Northwest intertie

Seattle City Light is hoping to increase the value of its assets and encourage the development of renewable resources in the region by selling a third party rights to a certain amount of capacity on the Pacific Northwest Intertie between the Washington-Oregon and California-Oregon borders.

The city-owned utility was to hold an informational meeting about the request for bids May 11 with bids due by May 28.

"The question came up if we could acquire greater value for our customers," by selling a portion of the intertie's capacity that is currently underutilized, said Robert Cromwell, director of contracts and resource acquisition for Seattle City Light.

Seattle City Light has rights to 3.3% north-south and south-north capacity on the 4,800-MW line, which is owned by the Bonneville Power Administration. Seattle City Light uses about half of that capacity for its own needs. The company uses the remaining capacity to move power between markets for short-term trades. That capacity would be sold to a third party under Seattle City Light's bid proposal.

Cromwell said that Seattle City Light believes there is an interest in capacity on the line because of regional transmission constraints caused by an expanding renewable energy market. BPA has service requests of 3,175 MW for access to its intertie lines, which include the two cross-border intertie 500-kV lines from Oregon to Washington and Oregon to California.

Seattle City Light is proposing a five-year contract for the capacity, with a maximum 72 MW capacity available north-to-south and 55 MW available south-to-north. Seattle City Light is not expected to need the capacity for the five-year period, Cromwell said.

"We are open to any alternatives," Cromwell said. The utility could pair a company wanting maximum capacity on the north-to-south route with another that would use the entire south-to-north capacity. Bidders must state a price in $/MW per month for much capacity, term and direction they would like.

Seattle City Light gained the rights to the capacity in 1994 when it sold power to Nordstrom's department stores. That agreement no longer exists. Any third-party agreement reached to use the capacity would have to be approved by BPA, but Cromwell said that BPA and Seattle City Light have clear terms that allow such a transaction, he said.

Questions and bid proposals should be sent via e-mail to paci@seattle.gov. Questions may also be directed to Steven Dadashi at 206-386-4512. — *Pam Radtke Russell*

National Grid issues RFP for default service in Mass., New Hampshire through October

National Grid last week issued a request for proposals seeking default service supplies in Massachusetts and New Hampshire. The supply period covers August 1 to October 31.

National Grid is seeking proposals from qualified power suppliers to supply firm, load-following power to meet its default service requirements in the New England states for certain customer groups.

National Grid said in the RFP that it is unable to predict the amount of load that will be required to meet the needs of each customer group under the solicitation, if any. "National Grid's customers are free to leave default service at any time to take service from competitive suppliers," the RFP notes.

However, in order to assist bidders in determining potential load requirements, National Grid is providing historical load information on its power procurement web site.

Under the RFP's schedule, proposal information is due May 21, indicative pricing is due June 2, and final pricing is due June 9. For additional details, go to www.nationalgridus.com/energysupply/current_procurement.asp.
— *Staff Report*

Illinois approves sale of 1,900 MW of competitive power contracts to Ameren

Illinois regulators on May 6 approved 12 competitive suppliers to sell up to 1,150 MW of on-peak power and up to 750 MW of off-peak power to Ameren Illinois for more than two years starting this June.

Approved by the Illinois Commerce Commission, the procurement by the Illinois Power Agency wraps up its latest round of power purchases on behalf of Ameren and Commonwealth Edison, the largest electric utilities in Illinois. The ICC approved the ComEd purchases May. IPA, created by S.B. 1592, the state's landmark 2007 rate relief and power procurement law, replaced Illinois' reverse power auction, held only once, in September 2006.

The most on-peak power to be provided, 1,150 MW, will come in July 2011, at a price of $47.87/MWh. Suppliers also will furnish 1,100 MW of on-peak power in August 2011 at a price of $47.99/MWh. The most off-peak power, 750 MW, will be delivered in January 2013 at a price $30.92/MWh.

Winning bidders were Ameren Energy Marketing, Cargill Power Markets, Constellation Energy Commodities Group, Dynegy Power Marketing, FirstEnergy Solutions, J.P. Morgan Ventures Energy, Macquarie Energy, Mercuria Energy America, Merrill Lynch Commodities, NextEra Energy Power Marketing and Sempra Energy Trading. All also were winners in ComEd's solicitation except Dynegy, Mercuria and Merrill Lynch. In addition, Ameren contracts were not awarded to Shell Energy North America and American Electric Power Service, both recipients in the ComEd process, although it is unclear if those two companies submitted bids in the Ameren competition. — *Bob Matyi*

Unitil Energy Systems issues solicitation for default service power supplies

New Hampshire based Unitil Energy Systems on May 11 released a request for proposals seeking default service power supplies.

UES is seeking competing fixed monthly price offers to supply a default service contract for 100% of large customer default service requirements, covering August 1 through October 31. There are no renewable portfolio standard requirements associated with the solicitation.

Proposal forms, including contract comments and indicative pricing, are due June 1. Final pricing is due June 8.

Questions should be directed to Michael Lundgren, 603-773-6549, lundgren@unitil.com.

UES provides electric service in the southeastern seacoast and state capital regions of New Hampshire. — *Staff Report*

WHOLESALE MARKETS

Energy management firm asks FERC to investigate 'irregularities' in recent PJM capacity auctions

An energy management company wants the Federal Energy Regulatory Commission to investigate alleged "irregularities" that it asserts resulted in a competitive advantage for certain bidders in the recent capacity auctions to integrate American Transmission Systems Inc. into the PJM Interconnection.

While not seeking to change the results of the auctions "for the simple reason that this could cause still further disruption and uncertainty," Enernoc's April 30 complaint calls for sanctions or remedies. If allowed to stand, the alleged irregularities introduced by ATSI-parent FirstEnergy have the "potential to shatter public confidence in the integrity of other wholesale market competitive procurements," the filing warned.

Comments on the complaint are due at FERC by May 20. "We disagree with the claims made by Enernoc" and will provide a full response at that time, said FirstEnergy spokeswoman Ellen Raines.

Because PJM's reliability pricing model acquires capacity three years in advance, the special auction was conducted to allow load serving entities in the ATSI zone to acquire capacity they will need once the transmission system is integrated into PJM on June 1, 2011.

In preparation for the integration auctions approved by FERC late last year, there was an extensive stakeholder process to inform potential bidders and others of their rights and obligations, explained Enernoc's filing (EL10-63). To ensure that all potential bidders had access to the same information, it continued, communications were limited to two means: open public stakeholder meetings and teleconferences, and the ATSI integration auction page on the PJM web site.

But according to the complaint, some potential or actual bidders had access to relevant, market-sensitive information that was not available to all other bidders.

It alleges that FirstEnergy made specific, material public statements in response to questions posted on the web site that "became false prior to the auctions but were not corrected in a timely fashion or appropriately qualified." That information was maintained on the site even as FirstEnergy engaged in "private negotiations" with a subset of bidders that made the information on the web site obsolete, the complaint asserted.

As a result, those bidders, including a FirstEnergy affiliate, had access to information that not only would allow them to tailor bidding strategies in ways denied to others, but also to influence changes to relevant market conditions in the ATSI auctions that other public bidders could not influence and were not told were subject to revision, the complaint alleges.

The failure "to abide by the letter, spirit and intent of the ATSI auction rules caused harm to the competitive market," the filing asserted. Advocating sanctions or remedies rather than revisions to the auction results, Enernoc said what it "seeks above all is non-repetition of similar scenarios" in the future.

"This situation was avoidable," it went on, and could have been "largely cured by timely disclosure or even prudent measures" within the settlement process to mitigate the anti-competitive impact. The integrity of FERC's bidding procedures and rules is "essential to maintain confidence in the competitiveness and fairness of the markets," Enernoc concluded. — *Craig Cano*

NYISO considers plan allowing generators to adjust real time bids to reflect costs

Generators with day-ahead market-committed incremental energy could increase their bids in real time to more accurately reflect actual production costs under a plan the New York Independent System Operator is considering.

The proposal would take into account in-day generation variables such as higher fuel costs and fuel-type switching. Approval by NYISO's Management Committee is being sought this month.

No NYISO mechanism is in place now for generators to manage increases in the costs incurred to meet their day-ahead market commitments.

The changes could improve risk management opportunities for generators, according to a presentation by Michelle Gerry, product business analyst for NYISO, to the grid operator's business issues committee.

Generators today are permitted to increase their bids in real time relative to their day-ahead market bids for incremental energy that was not scheduled in the day-ahead market.

Incremental energy refers to the range of megawatts above a generator's minimum generation MW value up to its upper operating limit.

The real-time scheduling and dispatch process would evaluate real-time bids that reflect generators' actual costs of energy production, improving the efficiency of the scheduling decisions and resulting in real-time locational marginal pricing and price signals that more accurately reflect in-day production costs, according to the business issues committee.

Market participants would submit fuel type and fuel cost information with their updated bids. Software would then use fuel costs to adjust reference levels.

The dollar amount of minimum generation bids could not be increased, and the megawatt amount of minimum generation bids could not be changed under the proposal.

Loads that buy day-ahead market energy would continue to pay the contracted day-ahead market price. Additionally, those in the balancing market would continue to buy and sell balancing energy at the real-time price.

NYISO does not have an estimate of generators' cost savings from the proposed feature, but NYISO and generators operating in the grid operator expect it to lower their costs.

An example provided by NYISO explains that if a generator were scheduled at a cost of $20/MWh in the day-ahead market but experienced fuel delivery complications and had to switch to an alternate fuel at a cost of $25/MWh in real time, the generator would have to operate at a $5/MWh loss under current rules.

To offset this loss, generators may choose to add a slight premium to their day-ahead bids using a risk premium calculation.

The proposed rules would allow generators to update their incremental energy bids in the event of cost increases in real time.

Under the NYISO example, if the generator had increased its bid in real time to $25/MWh, it may be replaced in the dispatch for a generator with a $22/MWh cost, which sets the LMP at $22/MWh.

While the original generator still has to purchase balancing market energy for its day-ahead position, it only experiences a $2/MWh loss — $20/MWh day-ahead payment and $22/MWh real-time balancing obligation — instead of a $5/MWh loss — $20/MWh day-ahead payment and $25/MWh cost of operation — thus reducing the potential day-ahead risk premium.
— *Patrick Badgley*

RTOs debate outcome of requirement that they become transaction counterparties

The pursuit of additional credit reforms for organized wholesale electric markets has revealed a philosophical difference in how regional transmission organizations view their roles.

At a technical conference held this week by the Federal Energy Regulatory Commission, RTO officials disagreed over whether a requirement that their organizations become the counterparty in energy transactions would fundamentally change the market structure.

"Some have suggested that the establishment of the RTO as a counterparty to pool transactions would represent a radical change," said PJM Vice President and General Counsel Vincent Duane. "I see it as conforming, explicitly in the rules, the functions that we already ... perform today."

But that view was not shared by either Michael Holstein, CFO at the Midwest Independent Transmission System Operator, or Daniel Shonkwiler, senior counsel at the California Independent System Operator.

The question of whether RTOs should become counterparties is presented by FERC's January 21 notice of proposed rulemaking on credit reform (Docket No. RM10-13). Under that proposal, grid operators would be required to revise their tariffs "to clarify their status as a party to each transaction so as to eliminate any ambiguity or question as to their ability to manage defaults and offset market obligations."

The concern is that although tariffs may provide for transaction netting, in which revenues owed to a market participant are offset by amounts owed by that market participant, that process may not be accepted by bankruptcy or other courts because the RTO is not a party to the transaction.

In considering a "setoff," which is a legal or contractual right under which parties that owe each other money apply their mutual debt against each other, the courts look for "mutuality." An important component for debts to be mutual is that they involve the same parties.

Duane asserted that PJM already is the counterparty in function, if not name. Were it faced with a situation in which a bankrupt or insolvent market participant asserted "we lacked mutuality and tried to undo the setoff in a bankruptcy context, our argument would be that we do have mutuality; we are the counterparty," he said.

"We have all this indicia to demonstrate that. We are the name on the billing statement, we are the designated beneficiary on the letter of credit, we collect in our name, we bill in our name, we clearly have that privity," Duane went on. "We would like to go one step further and establish that unequivocally," he said in support of making RTOs counterparties.

While acknowledging the risk identified by the NOPR appears remote, Duane suggested that a do-nothing approach is "a little bit like saying, 'well, I haven't died, so why should I buy life insurance?' Why not take prudent steps to address a known concern and a known risk."

Applauding the commission's proposal, Duane said he regards it as overdue. "It is a necessary step in maturing these large markets," he added. "The proposal here would remove a real disability that is a cloud over the enforcement of a broad set of rights that the RTOs have."

But the potential risk, "and I highlight the potential risk," that netting might not be allowed in a bankruptcy proceedings has not yet occurred, MISO's Holstein said in opposing counterparty status. He maintained that the proposed rule "will in fact have the potential to create greater harm which could be catastrophic to the RTO."

MISO is revenue-neutral, so if a market participant fails to pay, the RTO must "short pay" market participants that are due funds. It subsequently imposes uplift charges across the market to make up the difference to the participants that were initially short paid.

Such a feature would be inconsistent with the RTO being a true seller and buyer as the counterparty, Holstein suggested, meaning that MISO would have to pay the shortfall but have no means to do so. "We have no means to make somebody whole. In short, we would become insolvent and have to file for bankruptcy," he said. — *Craig Cano*

New England capacity market changes are not achievable by 2011 auctions: ISO

If ISO New England ultimately must make material changes to capacity market revisions that federal regulators accepted last month on an interim basis, there will not be adequate time to implement those changes prior to the June 2011 capacity auction as required in the April 23 order, the grid operator says.

The Federal Energy Regulatory Commission acknowledged that some of the revisions filed by ISO-NE and the New England Power Pool participants committee were not shown to be just and reasonable, but it allowed them to take effect while a paper hearing is held. With the next capacity auction to be held in August, the commission concluded that market participants needed certainty about the rules, explained that order.

But while accepting the full package of revisions, the order set some for hearing, including the modeling of capacity zones and the alternate price rule that triggers when an auction outcome is not competitive. Any revisions resulting from the hearing would take effect prospectively, beginning with the June 2011 auction that will be the fifth under the forward capacity market regime.

ISO-NE and the protesting parties must file briefs on July 1, with replies due by September 1.

Although that fifth auction is more than a year away, there are "several critical dates well in advance" of it, some as early as this October, ISO-NE said in a May 5 request for clarification or, in the alternative, rehearing. Even if the scope of changes resulting from the hearing is relatively narrow, "it will simply not be possible to complete the steps necessary" for new rules to take effect in time for the June 2011 auction, the filing asserted.

The commission should clarify last month's order to allow the accepted revisions to remain in effect until any new rules are approved, ISO-NE maintained, and it should extend the implementation date for any ordered changes to no earlier than the sixth FCM auction now scheduled for April 2012.

ISO-NE also files proposed ICR, resource qualification report

Separately last week, ISO-NE also filed its proposed installed capacity requirement (ICR) as well as an informational report on resource qualification for the upcoming auction to procure capacity for the 2013-14 commitment period.

The ICR is a measure of installed resources that are projected to be needed to meet reliability standards based on total forecasted load requirements in the New England control area as well as to ensure sufficient reserve capacity.

The grid operator's May 4 filing (Docket No. ER10-1182) proposed an ICR value of 33,043 MW. After subtracting 916 MW of Hydro Quebec Interconnection Capability Credits that allow certain entities in the region to move power across that interconnection, ISO-NE said it will need to procure 32,127 MW of capacity in the auction.

Capacity market rules also direct ISO-NE to calculate both a "local sourcing requirement," which is the minimum amount of capacity that must be electrically located within an import-constrained load zone, and a "maximum capacity limit," which is the maximum amount of capacity that can be procured in an export-constrained load zone to meet the ICR.

For the upcoming auction, ISO-NE proposed local sourcing requirements of 7,419 MW for the Connecticut load zone and 2,957 MW for the Northeast Massachusetts/Boston zone. In calculating the requirement, the ISO for the first time used a revised methodology accepted in the April 23 order, the filing noted. It also proposed a 3,187 MW maximum capacity limit for the export-constrained Maine load zone.

The May 4 informational filing (Docket No. ER10-1185) reported that ISO-NE has 37,271 MW of qualified existing capacity resources: 32,776 MW of intermittent and non-intermittent generating capacity; 3,139 MW of demand resources; and 1,356 MW from import capacity. In addition, ISO-NE qualified 886 MW of new generating capacity resources, 1,244 MW in import capacity resources and new demand resources of 1,011 MW.

The result is 40,412 MW of qualified capacity to meet the ICR of 32,127 MW. "As the informational filing demonstrates, the FCM continues to attract resources" to participate in the auctions, ISO-NE said. — *Craig Cano*

ISO New England seeks to eliminate FTR secondary market, citing potential risks

The harm from potential unmitigated risk outweighs benefits to be derived from retaining the little-used secondary market for financial transmission rights that is now administered by ISO New England, the region's market participants have agreed. So the ISO filed last week to temporarily eliminate the mechanism.

Currently, secondary FTR market transactions can be conducted either without ISO involvement or through its bilateral trading system known as eFTR. But since inception of the FTR market in March 2003, the volume of trades through eFTR has been very small, with only 47 transactions for 2,712 MW-months of FTRs, explained the filing (Docket No. ER10-1190).

That is a mere fraction of the 49,358.9 MW-months cleared in ISO-NE's most recent monthly FTR auction alone, ISO-NE said. And in the last three years, only one customer pairing used the eFTR system to conduct secondary trades on 11 paths for 67.8 MW-months of FTRs, it added.

Despite the insignificant volume of trades, however, the market administered by ISO-NE faces the risk of a significant default by a market participant, according to the filing.

That is because ISO-NE "has no authority through its market rules or system capabilities to verify that both parties to the trade are sufficiently collateralized prior to accepting the trade," explained testimony from Jeffrey Iafrati, manager of the ISO's market and credit risk department. While market participants must post sufficient financial assurance before acquiring FTRs in the ISO-run auctions, no such requirements exist for trades in the ISO-administered secondary market.

As a result, "unmitigated risk can be realized through the submittal of a single trade at any time," as long as the ISO-administered market remains available, Iafrati said.

Stakeholders considered two options to address that credit risk: implement necessary software enhancements to perform a credit check and confirm trades in the eFTR system, or remove the secondary FTR market provisions from the tariff until ISO-NE implements a long-term FTR (LFTR) market, as all organized electricity markets must do under Order 681.

The choice likely was made easy by the fact that dropping the tariff provision could take place immediately and at essentially no cost, while software enhancements could take as long as 13 months to complete at a cost of up to $810,000. Moreover, those enhancements would be rendered obsolete when the LFTR market software is put in place.

In an update filed last month, ISO-NE said it expects to initiate stakeholder review of financial assurance policy alternatives for LFTRs in the fourth quarter, setting in motion an implementation process that is likely to be completed no earlier than mid-2012.

While a financial assurance policy for the LFTR market has yet to be determined, it will "unquestionably include a provision to confirm sufficient financial assurance of secondary FTR trade participants prior to trade acceptance," Iafrati said.

In the meantime, the market participants have the ability to trade FTR positions bilaterally without involvement of ISO-NE or its software systems, he noted. "Such activity will be unaffected by this filing." *— Craig Cano*

ERCOT doubles volume of interruptible capacity, year over year, procured for February-May

The Electric Reliability Council of Texas more than doubled the amount of emergency interruptible load service capacity procured for the February through May time period, in comparison with the same period of 2009.

At an ERCOT Technical Advisory Committee meeting last week, Paul Wattles, ERCOT demand response supervisor, reported that for February through May, an average of 339.3 MW of capacity had been procured for weekday business hours, at an average price of about $7.96/MW. The total projected cost for this period is $6.7 million.

For the same period of 2009, an average of 165.1 MW of capacity was procured for weekday business hours at an average price of about $11.39/MW. The total adjusted cost for this period was $4.2 million.

ERCOT obtains EILS through a request for proposals. EILS represents a commitment by qualified loads to make themselves available for an interruption in their electricity supply in a grid emergency. The contract periods are for February through May, June through September, and October through January.

Bids for the summer EILS were due May 10 and the market notice with a summary of the EILS awards released will go out May 17, the ERCOT EILS procurement schedule states.

Clayton Greer, representing Morgan Stanley, asked why EILS gets a higher price than non-spinning reserves, inasmuch as non-spinning reserves are deployed regularly, while EILS has never actually been used. ERCOT's weighted average market clearing price for non-spinning reserves in 2009 was $3.10/MW, a February 16 market operations report shows.

Wattles said non-spinning reserves have 30 minutes to deploy, while EILS has just 10 minutes, which is one reason ERCOT considers the responsive reserve service, which also has a 10-minute deployment standard, a more appropriate comparison. The average market clearing price in 2009 for responsive reserve service was $10.20/MW.

In order to grow the EILS market, ERCOT pays EILS providers the rate that they bid, rather than at a market clearing price. The $7.96/MW average for the recent procurement is the average of those bids.

Started in February 2008, the EILS program has a Public Utility Commission of Texas cap of $50 million a year for up to 1,000 MW for every hour of the year. This equates to a price of about $5.70/MW, if both caps are reached, Wattles noted.

The EILS program can suspend bidders for not meeting availability standards — not being able to shed load when called upon at least 95% of the time. ERCOT suspended 25 bidders, in all, for violating availability standards during the February through May 2009 and June through September 2009 time periods. Wattles said 13 or 14 EILS providers would be suspended for the October 2009 through January 2010 period. *— Mark Watson*

ERCOT stakeholders discuss merits, pitfalls of delay to information on nodal power flows

A debate about delaying for 60 days information about power flows at nodes around Texas generated heat but ultimately no action at last week's Electric Reliability Council of Texas Technical Advisory Committee meeting.

At issue is Nodal Protocol Revision Request 209, which includes transmission and transformer voltages at each node among information that should be protected as competitively significant and requires a 60-day delay in the release of that information.

ERCOT, which now has four geographic zones, plans to implement a nodal market on December 1 that will include multiple trading locations.

Shams Siddiqi, representing the Lower Colorado River Authority, said NPRR 209 should be rejected because it would provide less transparency than what is currently available, such as information on flows at commercially significant zonal constraints and related elements in real time.

But Adrian Pieniazek, representing NRG Texas, said NPRR 209 is an attempt to bring the nodal protocols in line with the Public Utility Commission of Texas' rules against releasing "resource-specific information … and actual resource output for each type of service and for each resource at each settlement point" before the 60-day period has expired.

PUCT staff has said that the existing nodal protocol, before NPRR 209, requires the release of information in violation of the PUCT rule, Pieniazek said.

Siddiqi said the existing nodal protocols would, in fact, release information early in violation of the PUCT rule, but that NPRR 209 "overreaches" in delaying the release of information that would not violate the PUCT rule.

In response, Pieniazek said, "If there are flows that can be posted that don't release specific resource information, then that would be good."

Siddiqi said he wants the nodal protocols to narrow down what specific flows the PUCT thinks should be delayed.

"I am saying that I want everything posted, except what the PUC thinks is in conflict with the rule," he said.

Randy Jones, Calpine vice president for market design, said publishing the nodal flow information would be bad for the market in general. "You don't need to peek into our trading floor, unless you just want to kill competition," he said. "You would set up prime conditions for tacit collusion."

But Chris Brewster, of the city of Eastland, said whether the voltage is on or off does not indicate bidding behavior, which his organization thinks should be protected. "Whether the voltage is on or off … doesn't allow me to interpret offer curves or bidding behavior," Brewster said.

Randa Stephenson, of Luminant, said the company plans to ask the PUCT to clarify what information should be delayed for 60 days. *— Mark Watson*

ERCOT launches market trials of functions for planned nodal market

The Electric Reliability Council of Texas started market trials on all functions of the planned nodal market last week.

"Full functionality" market trials cover day-ahead and real-time markets, congestion revenue rights, reliability unit commitment, outage scheduler, payment settlements, network modeling, nodal reports and credit parameter enforcement.

For example, the real-time market and outage scheduler have been operating for more than 11 weeks, and the day-ahead market has done 10 auction runs since trials began on April 1. The congestion revenue rights auction for May was done April 16.

During the ERCOT Technical Advisory Committee meeting May 6, Jason Iacobucci, nodal program manager, said 174 qualified scheduling entities participated in the ERCOT day-ahead market on May 4, compared with 179 QSEs in the April 15 trial.

A QSE is an entity that is authorized to schedule generation or load across the transmission grid.

On May 4, day-ahead market trial on-peak prices ranged from $13.69/MWh to $47.34/MWh for hypothetical power ranging from 20,261 MW to 27,435 MW across the nodes. In the first half of April, on-peak prices in the day-ahead market trials, overall, ranged from less than $22/MWh to more than $36/MWh. In contrast, the on-peak prices in May 6's zonal day-ahead market ranged from a low of $29.25/MWh in the ERCOT West zone to a high of $37/MWh in the ERCOT Houston and South zones.

Additional market trials were scheduled for May 11, 12, 13, 18, 19, 20, and each week day for the last week in May.

In 2003, the Public Utility Commission of Texas charged ERCOT to develop a nodal wholesale market design to improve market and operating efficiencies, changing from four congestion management zones — North, Houston, South and West — to more than 4,000 individual nodes throughout the ERCOT footprint, which covers about 75% of the state and 85% of the load. *— Mark Watson*

TRANSMISSION

SoCal Ed plans to increase export capacity on Nevada-California grid line by 1,400 MW

Southern California Edison plans to upgrade a power line that would increase export capacity from Nevada into the Golden State by 1,400 MW.

SoCal Ed told the Nevada Public Utilities Commission that the project is designed to give solar developers in the Ivanpah Dry Lake area access to the California markets, according to a filing released by the PUC May 6.

The utility has contracts to buy 414 MW of solar energy being developed near Primm, Nevada, by BrightSource Energy, a solar developer based in Oakland, California. BrightSource will deliver power on the proposed Eldorado-Ivanpah transmission project.

The utility plans to upgrade an existing 115-kV with a double-circuit 220-kV line that will run 35 miles from Boulder City, Nevada, to a new substation planned for San Bernardino County, California, according to the filing. SoCal Ed expects to build the project in an existing US Bureau of Land Management right of way and a Boulder City easement.

California utilities face a target of getting 33% of their electric sales from renewable sources by 2020. Currently, about 17.4% of SoCal Ed's sales come from renewables, according to the California Public Utilities Commission.

BrightSource has a series of power purchase agreements with SoCal Ed totaling 1,300 MW. Among its projects, the company is closet to building its 400-MW Ivanpah solar plant near Primm, with the facility's output under contract to SoCal Ed and Pacific Gas and Electric.

In February, the Department of Energy said it would issue a $1.4 billion loan guarantee to BrightSource to build the Ivanpah concentrating solar project in the Mojave Desert on federally owned land (*GPR*, 25 Feb, 29). BrightSource plans to start building the plant later this year. *— Ethan Howland*

Iberdrola-led grid project in Maine will include pilot smart grid, solar power

Key parties reached an agreement last week on a major Maine transmission project by incorporating experiments with solar power and demand resources that backers say could revolutionize transmission planning.

Filed May 7 with regulators, the agreement revolves around a $1.4 billion transmission project proposed by Iberdrola subsidiary Central Maine Power. Opponents agreed to support the 350-mile line in return for smart grid pilot projects that test use of solar and demand response in lieu of new lines in two areas of the state.

"I think it is very exciting for anyone who cares about changing the transmission planning approach. In order to do transmission well, these non–transmission alternatives need to be explored," said Dan Sosland, executive director of Environment Northeast, which signed the agreement along with Central Maine Power, Maine's Office of Public Advocate, Conservation Law Foundation, Industrial Energy Consumers Group, GridSolar and several other parties.

The settlement, which requires approval by the Maine Public Utilities Commission, could end a long-standing dispute over the 345/115-kV transmission project. Opponents have argued that the line would be too extensive and costly, while the utility says it is necessary for reliability.

Underpinning the controversy was an unusual proposal by Maine-based GridSolar to develop up to 800-MW of solar in lieu of much of the transmission. While solar has been installed in place of distribution lines, using it for transmission is largely untested.

The agreement does not grant GridSolar it full wish, but does allows the solar company to experiment with the concept in two locations, the city of Portland and along the state's large midcoast. CMP will contract with GridSolar to develop the pilot projects by 2012. The size of the projects is yet to be determined.

Data from the pilot programs may move the concept "rapidly into other states and throughout the country" where large transmission projects are in planning, said Richard Silkman, founding and co-managing partner at GridSolar.

The agreement also calls for CMP, one of New England's major transmission owners, to commit $1.5 million toward study and reform of transmission planning and funding in New England. Currently, the ISO spreads transmission costs over the six New England states if a project is meant to improve system reliability. However, alternatives to transmission do not receive the same socialized funding. As a result, the solar, demand response and other alternatives find themselves at a competitive disadvantage during regulatory review, according to Sosland.

Other provisions within the agreement obligate CMP to secure all cost-effective energy efficiency before securing supply, provide $17 million for low income weatherization, and support pilot programs to increase use of electric cars in Maine.

The PUC is expected to take up the settlement May 14. It is unclear at this point whether or not the board will support the deal, Silkman and Sosland said. The settlement does not comply with a recent PUC hearing examiners' report making significant cuts in the scope of the 350-mile project. The examiners called for a cut in project costs from $1.55 billion to $1 billion. Instead, the settlement only reduces the price tag to $1.4 billion by eliminating some feeder lines.

The new transmission line is meant to increase transfer capability between Maine and New Hampshire to 2,850 MW from 1,600 MW heading south and to 1,940 MW from 1,360 MW heading north. It also is expected to give Maine wind generators increased access to southern New England markets. *— Lisa Wood*

FORECASTS

PJM report sees adequate power supplies to meet expected summer peak demand

Peak use of electricity in the PJM Interconnection this summer is expected to increase 1.5% from last year, when adjusted for the relatively cool summer weather in 2009, and demand response is expected to play a significant role in reducing that peak, the grid operator said earlier this month.

In a summer outlook, PJM said it has 162,903 MW of available generation to meet the forecast peak demand of 135,750 MW. Additionally, it anticipates cutting that peak by more than 6% through voluntary consumer demand reductions of about 8,525 MW.

"PJM and our members are ready to handle the expected summer conditions," said Senior Vice President of Operations Michael Kormos in a statement. "However, until transmission additions can relieve congestion, we expect we will continue to reschedule generation to accommodate peak load conditions," he observed.

Separately, in a presentation at PJM's annual meeting, Market Monitor Joseph Bowring noted that congestion charges on the grid in 2009 tumbled by two-thirds from the prior year, settling at about $719 million. That's the lowest level since 2003 and represented just 3% of PJM total billings, compared with the 6% average for the 2003-2009 period.

Bowring, who is president of Monitoring Analytics, also noted that last year's average real-time load of 76,035 MWh dropped 4.4% from 79,515 MWh in 2008, which in turn was down 2.7% from the prior year. The real-time, load-weighted average locational marginal price was $39.05/MWh in 2009, a 45.1% drop from 2008.

According to Bowring, who reiterated findings from his annual state of the market report for 2009, the total price for power in PJM was $55.58/MWh. By far the largest component, representing 70.2% of the total price, was the load-weighted energy cost of $39.05/MWh. Other major components were the $10.75/MWh cost of capacity (19.3%) and $4/MWh in transmission service charges (7.2%).

As for the summer outlook, PJM said the forecast was based on normal weather conditions. If the weather is unusually hot, air conditioning use could drive demand as high as 144,612 MW, it said. That would fall just short of the grid operator's all-time record demand of 144,644 MW reached in the summer of 2006.

Touting the role that demand response is expected to play, PJM noted that the 8,525 MW of available resources represents a five-fold increase since 2006. *— Craig Cano*

RENEWABLE ENERGY

California PUC bows to pressure to suspend renewable energy credit trade

Faced with strong opposition from the state's investor-owned utilities, merchant generators and others, the California Public Utilities Commission on May 6 agreed to suspend its plan authorizing trading of renewable energy credits.

The PUC in March approved a REC trading program aimed at helping the state satisfy its aggressive renewable energy goal. California has set a target of getting 20% of its electricity from renewables by 2010, and 33% by 2020.

The March plan was designed to address utility concerns that an earlier draft would have crimped the market by classifying most out-of-state renewable energy transactions as "REC-only," thereby eliminating the energy component of the deal.

But Pacific Gas and Electric, Southern California Edison and San Diego Gas & Electric, and the Independent Energy Producers Association in April asked the commission to stay the decision, saying it would still thwart renewable energy development by classifying most out-of-state transactions as REC-only deals.

"The decision's narrow definition of bundled transactions 'overnight' transformed classification of numerous existing and prospective projects from bundled to REC-only," IEP said, even though those projects are required to deliver energy to California.

In addition, the decision's 25% cap on use of RECs for RPS compliance means that IOUs "instantly became uncertain whether the transactions they were pursuing and negotiations would help them meet their RPS obligations," IEP said.

"It is clear that the decision has generated a substantial amount of hand-wringing" by the very parties required to meet the state's renewables mandates, PUC President Michael Peevey said. He said he believes a great deal of uncertainty can be avoided if the problems are quickly tackled.

In an effort to reduce regulatory uncertainty associated with "petitions for modification," the decision suspended REC-only contracts signed since the REC trading program went into effect.

But commissioners John Bohn and Dian Grueneich warned that staying the REC decision would still signal policy uncertainty to the investment community and could jeopardize investments in renewable resources.

After unanimously approving REC trading in March, the PUC "is now saying we really didn't mean what we decided a few weeks ago," Bohn said. While Grueneich voted against the stay, Bohn voted in favor of the stay, saying any decision made by the commission is meaningless without the support of state lawmakers.

Before voting against the stay, Grueneich asserted that IOUs in recent weeks have been lobbying lawmakers for the stay.

The suspension of the REC program will remain in effect until the petitions are resolved.

Also at the meeting, the PUC approved a Southern California Edison 20-year contract with both Ram Power and Orita Geothermal for a total of 50-MW geothermal resources.

The Orita 1 geothermal facility will be based in Imperial County, in Southern California, and is expected to start delivery in 2013. The PUC authorized SoCal Ed to execute two additional deals with similar terms for future projects with Ram Power and Orita Geothermal. *— Lisa Weinzimer*

Xcel plans to cut back solar power purchases as Colorado transmission project faces delays

Xcel Energy is scaling back planned solar power purchases because of a delay in a proposed power line into one of Colorado's renewable energy zones.

At issue is a 230-kV and 345-kV transmission project running roughly 130 miles from the San Luis Valley to near Xcel's Comanche power station near Pueblo, Colorado. Xcel and Tri-State Generation and Transmission Association in May 2009 asked the Colorado Public Utilities Commission for permission to build the $180 million project to improve reliability and provide an outlet for solar and wind power.

The line, however, is being opposed by Louis Bacon, a billionaire who founded a hedge fund and owns Trinchera ranch, which would be crossed by a roughly 18-mile segment of the line. The project is supported, with some conditions, by PUC staff, the Colorado Energy Office, Western Resources Advocates and the Interwest Energy Alliance, which represents renewable developers.

The transmission project, in part, grew out of a Colorado law that requires regulated utilities to develop power lines to reach the state's five renewable zones, including the San Luis Valley with its roughly 5,500 MW in solar potential.

Under the renewable transmission law created by S.B. 100, the PUC was supposed to have ruled on the application by Xcel and Tri-State within 180 days, Craig Cox, Interwest executive director, said last week. Trinchera lawyers have used various delaying tactics, Cox alleges. "It's turned S.B. 100 upside down," he said.

The PUC is currently developing new rules for transmission planning, which Cox hopes will "restore the objectives we were making with S.B. 100."

The opposition to the project is creating uncertainty, preventing Xcel from entering into solar power purchase agreements with developers, Xcel told the PUC in a May 4 filing. "No independent power producer can obtain the necessary financial commitments to develop generation projects of this magnitude without certainty that the utility will pay for that power," Xcel said.

As a result, the utility plans to scale back the solar purchases. The PUC late last year approved a plan by Xcel to add up to 600 MW of concentrating solar power with storage as well as 750 MW of wind and conventional PV capacity.

Xcel expected most of the solar capacity to be located in the San Luis Valley, said Mark Stutz, an Xcel spokesman. The utility is still negotiating with solar developers and cannot reveal details of the possible projects, he said.

Trinchera Ranch estimates that existing power lines could allow 300 MW to 500 MW to be exported from the San Luis Valley. Xcel believes there is much less available capacity, Stutz said. Further, the valley can support significantly more than 500 MW of solar, he said.

Solar developers in the San Luis Valley have given Xcel transmission interconnection requests totaling 2,200 MW, according to a PUC filing. Xcel estimates its proposed transmission project, which could be expanded, would allow for about 1,500 MW of solar capacity to use the line.

Xcel is now reviewing its plans and is unsure exactly how much it will need to trim its solar purchases from the San Luis Valley. It will revise its solar plans in a filing to be made at the PUC in several weeks, Stutz said. *— Ethan Howland*

DOE awards $62 mil to 13 projects using concentrated solar technology

The Department of Energy said last week it had awarded $62 million in grants for 13 concentrated solar power projects.

The funding will support research, development and demonstration projects with CSP systems, components and thermal energy storage, with the goal of accelerating the market-readiness of the technology that DOE said could eventually replace coal-fired power plants.

CSP technology uses the sun to heat a liquid that drives traditional boiler-turbine-generator. CSP plants also can include energy storage systems that allow them to produce electricity if the sun is not shining.

"Developing low-cost, renewable energy generation is crucial to meeting our nation's increasing demands for electricity," Energy Secretary Steven Chu said in a statement. "By investing in the development of low-cost solar technologies we can create new jobs and pave the way towards a clean-energy future."

DOE said the grants seek to improve CSP systems so they can operate about 18 hours per day, a level of production that the department said could make it possible to supplant traditional coal-fired power plants.

Three projects were selected for grants to develop prototype CSP systems for field testing. Colorado-based Abengoa Solar received $10.6 million, California-based eSolar received $10.8 million, and California-based Pratt & Whitney Rocketdyne received $10.2 million.

Ten projects received funding for further research and development into CSP baseload systems. California-based General Atomics received $2.1 million; Alabama-based HiTek Services received $3 million, Washington-based Infinia received $3 million, Pennsylvania-based PPG Industries received $3 million, California-based SENER Engineering and Systems received $3.1 million, New Mexico-based SkyFuel received $4.3 million, California-based SunTrough Energy received $4.5 million, California-based Terrafore received $1.4 million, the University of South Florida received $2.5 million, and Massachusetts-based Wilson TurboPower received $3.7 million. *— Herman Wang*

Small-scale solar power could see costs comparable to grid retail prices by 2020: IEA

Small-scale solar photovoltaic technology and larger-scale concentrated solar power plants could reach grid parity — achieving costs comparable to grid retail prices — in many areas by 2020 and could supply a quarter of the world's electricity by mid-century, the head of the International Energy Agency said this week.

IEA Executive Director Nobuo Tanaka said that PV, which uses solar panels to convert sunlight to electricity, and CSP, in which large metal troughs or mirrors concentrate the sun's heat to power turbines, are advancing rapidly in many parts of the world.

IEA released roadmaps on PV and CSP development on May 11 that showed how the technologies could become competitive in the coming decades without subsidies, "highlighting that the two technologies will deploy in different yet complementary ways: PV mostly for on-grid distributed generation in many regions and CSP largely providing dispatchable electricity at utility scale from regions with brightest sun and clearest skies," the agency said.

Utility-scale PV plants will take until about 2030 to reach grid parity in the sunniest regions, Tanaka said.

Initially some type of government support, such as a feed-in tariff, is needed "to make the technologies viable," he said in an interview. "Eventually subsidies will decline. A feed-in tariff must gradually decline and be phased out."

Government policy in Spain offers a cautionary tale about how governments should manage feed-in tariffs for solar power, he said.

The Spanish feed-in tariffs for solar energy "in the beginning were a little too high. They attracted a lot of investment to Spain," he said. But the government drastically reduced tariffs and capped the amount of capacity eligible for subsidies beginning in 2009, sending the nation's PV industry into a tailspin.

"You have to prepare for the decline" in financial support, he said. "Otherwise you can't send a clear message to investors. The Spanish government has learned about the necessity of adjusting tariffs, and is moving toward a gradual phase-out."

In the near term, governments should provide clear signals to investors about what support they will provide to foster renewables development, Tanaka said, including placing a price on carbon emissions and providing R&D financing, while utilities should seize on these market openings.

"It's a good opportunity for industry investments," he said. "Most investments should be made by industry, not by governments." *— David Jones*

REGULATION & LEGISLATION

FERC approves grid dispute resolution between North Dakota wind developers

A settlement resolving an interconnection dispute among a number of wind project developers in North Dakota has been approved by the Federal Energy Regulatory Commission.

The agreement provides an orderly process for interconnecting specific generation projects to the Minnkota Power Cooperative transmission system, said the May 6 order (Docket No. EL08-86).

Renewable Energy Systems Americas and PEAK Wind Development in 2008 accused a utility and power cooperative of secretly contriving to build a transmission line and unduly discriminate against them in favor of a project sitting lower in the Midwest Independent Transmission System Operator interconnection queue. RES Americas and PEAK Wind are working together on the 400-MW Glacier Ridge project in Barnes County, North Dakota.

The complaint accused Otter Tail Power and Minnkota Power Cooperative of building the 60-mile, 230-kV Pillsbury line even though it was not regionally planned as required by Order 890.

It claimed that Otter Tail and Minnkota secretly conspired to interconnect and accommodate an out-of-queue wind generation project being developed by Otter Tail and the former FPL Energy, now called NextEra Energy Resources, on land adjacent to the Glacier Ridge project.

NextEra is developing several other wind power facilities, including an independent project called Ashtabula.

Under a "handshake and hug" agreement, NextEra promised to sell energy to Minnkota at a below-market price for 25 years in return for expedited access to the grid in 2008, which would allow it to earn production tax credits, RES Americas and PEAK Wind said in the complaint.

FERC set the matter for hearing and settlement judge procedures.

In January, NextEra, RES Americas, PEAK Wind and its affiliates, Otter Tail and Minnkota submitted an agreement with the terms for Minnkota to study the interconnection of the Glacier Ridge project and the Ashtabula project at Maple River.

The settlement also provides that both projects hold the same place in the queue for purposes of conducting studies. NextEra and RES Americas and PEAK Wind will be responsible for the costs of any advanced studies they request or any research that costs more than $500,000.

The deal also outlines that NextEra will have a right to half of any excess capacity on the Pillsbury I line and what would happen to the additional capacity if either entity opts not to use it.

All capacity on the Pillsbury 1 Line related to the interconnection of the other wind projects will be unaffected by the settlement. — *Esther Whieldon*

Renewables legislation on wind energy, tire burning, fails in Illinois Senate

A pair of renewable energy bills, including a proposal to help ensure Illinois wind energy developers would share in an upcoming long-term renewable power procurement by the state, officially died May 7as the General Assembly neared adjournment.

But while the demise of the so-called Illinois "wind preference" bill was mourned by the environmental community and, in particular, the Illinois Wind Energy Association, there was less sadness over the demise of a measure that would have included tire incineration in the state's definition of renewable energy.

For the past few weeks, S.B. 3686 had been on life support in the state Senate as talks continued between Exelon and its Commonwealth Edison subsidiary and supporters of the bill that would give a preference to in-state wind projects in the Illinois Power Agency's solicitation for 20-year renewable energy contracts for ComEd and Ameren Illinois. Exelon/ComEd voiced concern that increased wind power development in Illinois might have a depressing effect on wholesale power prices. Exelon is the nation's largest nuclear generator, with about 17,000 MW of nuclear capacity.

A spokeswoman for state Senator Don Harmon, a Democrat and chief sponsor of S.B. 3686, confirmed the bill was dead for 2010. So did IWEA director Kevin Borgia, whose trade group campaigned hard for its approval.

Failure of the Illinois legislation to pass will mean financing problems for in-state developers, Borgia said. "With credit markets like they are, banks are financing only the most favorable projects. The most favorable ones are the ones that can go to the bank and say 'We've got a buyer for 20 years.'"

Meanwhile, the Senate defeated a measure that would have added tire burning to the list of acceptable renewables under Illinois' five-year-old renewable portfolio standard law. The measure, S.B. 380, was defeated 26-17 by the Senate. Late last month, the proposal passed the House of Representatives, 61-45. Under the RPS, utilities must get at least 25% of their power from renewables by 2025, with a majority to come from wind. — *Bob Matyi*

NYISO to get $37.8 million from DOE for development of smart grid systems

The New York Independent System Operator will receive $37.8 million from the Department of Energy to deploy smart grid technologies, the grid operator said this week.

The funds, provided under the smart grid investment grant program, will support a $75.7 million project to enhance the reliability and efficiency of the state's power grid.

The project involves the creation of a statewide phasor measurement network and the installation of capacitor banks throughout the state.

NYISO signed an agreement with all eight of New York's transmission owners to work together to implement the project. Those owners are Central Hudson Gas & Electric, Consolidated Edison of New York, Orange and Rockland, Long Island Power Authority, National Grid, New York State Electric & Gas, Rochester Gas and Electric, and the New York Power Authority.

The agreements call for the work to be completed over a three-year period starting July 1. NYISO will report to DOE on the results of the project for two additional years.

The components of the smart grid investment grant project include the deployment of a statewide phasor measurement network to enhance NYISO's ability to detect system vulnerabilities and avoid potential blackouts. The project involves installing 39 phasor measurement units at various locations across the high-voltage grid.

The units transmit power system data 60 times each second, enabling faster responses to grid events. Current monitoring systems sample conditions every two to six seconds.

Also being installed are capacitors to improve the control and coordination of voltage on the New York power grid. Currently, ideal voltage levels cannot be maintained on many transmission lines, creating operating inefficiencies and leading to power lost in transit, NYISO said. — *Patrick Badgley*

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