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Global Power Report

May 6, 2010

Proposed PPL-E.ON U.S. merger could signal long-anticipated power sector consolidation

The long-anticipated consolidation in the power sector seems to have finally arrived, aided by a thaw in the credit markets.

PPL Corp.'s April 28 announcement of its plan to acquire E.ON U.S., the parent company of Louisville Gas & Electric and Kentucky Utilities, is the most recent deal, but it was preceded by two acquisition announcements in the past two weeks.

Calpine on April 21 agreed to buy Conectiv Energy's 4,490-MW fleet of fossil plants in the PJM Interconnection from Pepco Holdings for $1.65 billion (*GPR*, 22 GPR, 1). The prior week, Mirant and RRI Energy announced plans to merge (*GPR*, 15 April, 1).

The April announcements were preceded by the announcement in February that FirstEnergy and Allegheny Energy would merge in a $4.7 billion stock-swap transaction (*GPR*, 18 Feb, 1).

"You are going to see a lot more of these," said an analyst who asked not to be identified by name. Power companies are bulking up in terms of cash flow, market share and generation capacity, he said.

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EPA analysts receive summary of climate/energy bill for modeling

Analysts at the Environmental Protection Agency May 5 received a summary of climate change and energy policy legislation from three senators working on the much-anticipated bill, the agency said.

Senators John Kerry, a Massachusetts Democrat, Lindsey Graham, a South Carolina Republican, and Joe Lieberman, a Connecticut Independent Democrat, asked the agency to begin economic computer modeling based on their description of the draft bill.

The senators did not send EPA actual legislative text, the agency said.

EPA said it will take six to eight weeks to model the description of the draft bill.

"EPA's modelers are now examining the description to determine whether it contains all of the information that EPA needs in order to run its models," the agency said in a statement.

Meanwhile, Senate discussion of the bill, which would allow some offshore oil and gas drilling in order to win votes, was focused on the major crude oil leak in the Gulf of Mexico.

Speaking May 4, Senate Majority Leader Harry Reid remarked that the "staggeringly scary" leak should prod lawmakers to pass

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Duke could quadruple its wind capacity to 3,000 MW by 2020, says new unit head

A wind-energy veteran hired to help Duke Energy significantly expand its portfolio said this week that he expects Duke to at least quadruple to 3,000 MW how much wind capacity it has online by 2020.

Tony Dorazio, who was named senior vice president for wind energy development by Duke Energy Generation Services in January, said that Duke currently has 735 MW of wind capacity in operation, with another 251 MW under construction and expected to begin commercial operation by the end of 2010.

"Right now we have about 1,500 MW [of wind projects] in advanced-stage development, 2,200 MW in mid-stage, and 1,800 MW in early-stage development," Dorazio said, adding that Duke also has "two projects that we are looking at acquiring. They are very-late stage, they total about 500 MW," and they are located in Oklahoma, a hot bed of wind development activity.

Prior to joining Duke, Dorazio helped launch BP Alternative Energy's wind power business and, before that, served as a vice president at Portland, Oregon-based Vestas-American Wind Technology.

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Duke's current project pipeline includes four projects totaling about 800 MW that were submitted in response to recent solicitations for wind power, the Duke executive said. The company currently is awaiting word on whether one or more of its proposals will be selected; three of the proposed projects would be completed in 2011 and the fourth would come online in 2012, he said.

"We'd like to add 200 to 300 MW a year, on average," to Duke's wind portfolio, Dorazio said, but in some years Duke will likely add more, or less, depending on market conditions and project opportunities.

He said that while Duke's focus is on developing wind projects it acquired through its acquisitions of Tierra Energy's wind business in 2007 and Catamount Energy in 2008, the company also is open to acquiring projects from others. "We are opportunistic. If a late-stage project is out there with a power purchase agreement and we can help get the project 'over the finish line'" Duke would consider buying it.

Duke and other large, well-capitalized companies like NextEra Energy Resources "do have an advantage" in the current economic environment, not only because of their financial strength but because of their "ability to use the tax credits that are out there" and their experience in developing and building large generation projects. "A lot of utilities [considering wind PPAs] like to see experienced companies like us in this game."

Duke's existing wind assets include 495 MW in three wind farms in Texas, 170 MW in three wind farms in Wyoming, and a 70-MW wind farm in Pennsylvania. The two projects it is building this year are the 200-MW Top of the World wind farm in Converse County, Wyoming, and the 51-MW Kit Carson wind farm in Kit Carson County, Colorado.

"About 99%" of the company's existing wind farms and planned projects are, or will be, tied to long-term PPAs, an approach that eases project financing and minimizes overall risk, said Dorazio.

"Probably the only area you might think of doing anything other than a PPA-based project would be in the [Electric Reliability Council of Texas] region," which features a competitive wholesale market and ample wind resources, he said. Still, Texas "right now is a tough state. Power prices are way off" because of sagging prices for natural gas, the predominantly power plant fuel in ERCOT, "and it's been very difficult to get PPAs there" because utilities and retail electric providers have slowed the pace of their power purchases.

Among the Texas projects that Duke has been seeking to advance is a wind farm of up to 300 MW in Willacy County. Dorazio said that the company is "looking at a few options for developing that project, but we don't know if we will be building it next year" — as Duke had initially hoped. — *Housley Carr*

Proposed PPL-E.ON U.S. merger could signal long-anticipated consolidation ... from page 1

In PPL's case President, Chairman and CEO James Miller called the proposed E.ON US acquisition "truly transformational."

The combination would convert PPL from a company with 70% of its EBITDA from unregulated assets and 30% from regulated assets to a company with an almost equal balance between competitive and regulated businesses.

E.ON's regulated Kentucky utilities will bring 1.2 million

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utility customers (gas and electric) to PPL, giving it 5.2 million customers. E.ON will also add about $2.6 billion in revenues to give the combined company just over $10 billion in revenues. And, in terms of generation, E.ON brings 8,077 MW of regulated generation to the combined company where PPL now has no regulated generation and 11,695 MW of competitive generation, most of its in Pennsylvania.

With regulated power prices just ending in Pennsylvania, competitive generation has been a concern for PPL. The company was facing a challenge in maintaining its investment grade BBB credit rating if its cash flow continued to be based on volatile wholesale power prices.

The move toward a greater proportion of regulated assets and earnings is "the model of the future," said the analyst. When it was pointed out that deregulated markets were once touted as the model of the future, he said, "the future has changed." Low natural gas prices, low wholesale power prices and the recession together paint a bleak outlook for competitive generation, he said.

Miller now says PPL will look to its competitive generation fleet to provide "upside benefits … when wholesale power market prices improve." And, he said, PPL would be willing "to explore the sale of non-core assets."

In addition to possible asset sales, PPL said it plans to pay for the $7.625 billion transaction with $6.7 billion of cash and through the assumption of $925 million of tax-exempt debt. The company said it has committed bridge financing in place from Bank of America Merrill Lynch and Credit Suisse.

Miller said the permanent financing plan would include a combination of common equity, first mortgage bonds, corporate debt, high-equity-content securities, cash on hand and, as mentioned, the possible sale of non-core assets.

The $7.625 million price tag includes $450 million of tax benefits. Back out the tax benefits and the $7.175 billion price puts the acquisition in line with the market price for regulated peer companies, said Miller.

In the near term, Daniele Seitz, vice president, electric utilities and IPPs at Dudack Research Group, said PPL is probably looking at a "massive jump" in earnings this year from its competitive generation in Pennsylvania because it was able to lock in good prices in the state's provider of last resort (POLR) auction. Further out, however, those competitive earnings could be lower, she said.

That makes this a good time for PPL to do the E.ON deal, said Seitz. The dilution that the deal will bring will be overshadowed, at least in the near term, by the earnings boost she expects PPL to enjoy this year, she said.

Beyond that, she said that Miller was never a big fan of competitive markets and that he had said publicly many times that he had no interest in buying more merchant assets. "He doesn't have the stomach to play around with hedging and he doesn't have the scale," she said.

So, in her view, PPL had to do something because it was not big enough to compete in the competitive market. "If you don't have 25,000 MW in the PJM [Interconnection region] you can't throw around your weight," said Seitz.

Scaling up to play in PJM was a driving factor in the recently announced Calpine-Conectiv deal. It will add 4,490 MW to Calpine's 25,000-MW generation fleet and give the company a presence in the PJM region where it currently has only a single power plant.

Discussing the deal in April, Calpine CEO Jack Fusco said the company is also looking for other opportunities in its three key regions: California, Texas and the Mid-Atlantic/Northeast region where there are competitive wholesale markets that are "IPP friendly."

The planned merger of Mirant and RRI Energy is also a move to create critical mass, in this case for two merchant generators facing tough times. Analysts at Macquarie Equities Research said they viewed the RRI-Mirant merger, as a "survival strategy," given their "grim outlook for dark spreads and likely coal plant retirements."

The merged company, to be called GenOn, would have almost 24,700 MW of generation, putting it close to the 25,000-MW threshold that some analysts say is necessary for a generator to compete in unregulated markets.

The proposed merger of FirstEnergy and Allegheny Energy also would provide the combined company with the scale seen as necessary to survive and thrive in competitive power markets.

Many of the other companies that operate in the PJM generation market are far bigger in terms of generating fleets than either Allegheny, with 9,730 MW, or FirstEnergy, with 14,000 MW.

American Electric Power has 38,000 MW of capacity. Exelon has 31,290 MW of capacity, and Dominion has power plants totaling 27,500 MW. Tellingly, only PPL, with 11,695 MW, is currently on par with FirstEnergy and Allegheny in terms of generation capacity in PJM. — *Peter Maloney*

Quote of the Week...

"Why would anybody be building anything? We are sitting on massive surpluses." — Robert Stoddard, vice president and practice leader of the energy and environment practice at Charles River Associates discussing investment incentives in the capacity market of the US Northeast (see story, page 15).

EPA receives summary of climate/energy bill for modeling ... from page 1

the legislation.

Rather than endanger the measure, which aims to cut greenhouse gas emissions and promote renewable energy, the oil leak "should spur it on," said Reid, a Nevada Democrat. "We have to take care of this issue." But he also said the Senate would probably retreat for a time from the drilling provisions.

The April 20 explosion of BP drilling rig Deepwater Horizon killed 11 workers and has resulted in an oil slick of unprecedented size in US waters. Thousands of gallons oil a day have been gushing into the Gulf and threaten states' coastlines.

"So I think, rather than slow us up, I think it should expedite our doing energy legislation," Reid said. — *Cathy Cash*

COMPANY NEWS

Duke Energy working with Chinese partners on possible power investments in Americas

Duke Energy is working with Chinese partners on possible "co-investing" in electricity-related assets in North and South America, Duke Chairman, President and CEO Jim Rogers said May 4, adding that such investments might include nuclear plants, coal plants and even electric utilities.

Rogers said during an earnings related conference call with analysts that Duke "see[s] opportunities for [Chinese companies] to partner with us on existing or new assets that we might develop or acquire ... in the US as well as in South America."

Duke's top executive did not name the Chinese companies with which Duke might co-invest in North and South American electric assets, however, Duke last year formed technology partnerships with Huaneng Group, China's largest electric utility, and with ENN Group, one of China's largest privately held, diversified energy companies.

Last summer, Huaneng and Duke agreed to collaborate on developing new technologies for coal plants and renewable generation. Duke and ENN Group late last year said the two companies would jointly develop solar power projects in the US.

Rogers noted this week that Duke is "in the [energy] infrastructure business" and that Chinese companies are developing nuclear, clean-coal, wind and solar projects "faster than anyone in the world." Chinese companies also have a low cost of capital, he said, and China may well be looking for ways to improve the returns they now receive on some $1.6 trillion in US Treasuries that it holds.

Chinese companies "have demonstrated a great ability to build new [generating] facilities and build them fast, and to build quality facilities," he said, adding that "clearly we see partnerships making sense," in part to learn from China's ongoing experience in building new nuclear plants and coal plants with carbon capture and sequestration.

"I do envision that they could participate in joint ownership of nuclear plants or maybe coal facilities or even joint ownership of a utility in the US" with Duke, Rogers said.

Rogers noted that he "believe[s] that we are in the beginning of another wave of consolidation" in the US, and that Duke tried its best to acquire E.ON U.S., the parent company of Louisville Gas & Electric and Kentucky Utilities, which instead is being sold to PPL (*see story, page 1*).

The company also plans to expand in the renewable energy arena, and has the potential for 3,000 MW of wind capacity in its portfolio by 2020, according to an industry expert (*see story, page 1*).

Rogers made his comments during a conference call with analysts to discuss the company's quarterly earnings.

Duke reported earnings of $445 million, or 34 cents/share, on revenue of $3.594 billion for the three months ended March 31, compared with earnings of $344 million, or 27 cents/share, on revenue of $3.312 billion in the same period in 2009.

Rogers said the improved results were "primarily due to three factors: favorable weather increases in weather-normalized sales volumes, and rate increases in North Carolina, South Carolina, Ohio and Kentucky" that were implemented in the months after last year's first quarter. He added, however, that those gains "were partially offset by lower retail sales volumes due to competition in Ohio, the effects of which were partially offset by customer acquisition efforts by our competitive retail subsidiary." *— Housley Carr*

Emera plans to take a 38% stake in utility serving island of Barbados

Emera Inc. on May 3 said it plans to acquire a 38% interest in Light & Power Holdings Ltd., the parent company of Barbados Light & Power, the sole utility operator on the island of Barbados, from Leucadia National Corp. for $85 million.

Barbados Light & Power serves 120,000 customers and has three generation stations with 239 MW of installed capacity. The island's regulatory regime allows a full fuel pass-through mechanism.

Emera said the 38% investment would make it the largest single shareholder of Light & Power Holdings. Approximately 62% of LPH is locally held by 2,700 Barbadian shareholders, including the National Insurance Board of Barbados, which owns 23%.

Light & Power Holdings is Emera's third investment in the Caribbean. It has a 19% investment in St. Lucia Electricity Services Ltd., a vertically integrated monopoly utility on the island of St. Lucia, and a 25% indirect interest in Grand Bahama Power Co., a vertically integrated electric utility on the Grand Bahama Island.

Emera expects the transaction to close in the second quarter. It is not subject to regulatory approval. Emera said the transaction would be financed with existing credit facilities and is expected to be immediately accretive.

Emera is an energy and services company with $5.3 billion in assets. Approximately 94% of the company's revenues are earned by Nova Scotia Power, Bangor Hydro Electric and the Brunswick Pipeline.

In addition to electric utility investments, Emera owns Bayside Power, a 260-MW gas-fired plant in Saint John, New Brunswick; Emera Energy Services, a physical natural gas and power marketing and asset management business; a joint venture interest in Bear Swamp, a 600-MW pumped storage hydroelectric facility in northern Massachusetts; a 12.9% interest in the Maritimes & Northeast Pipeline, and an 8.2% interest in Open Hydro. *— Staff Report*

Swiss commodity trader Vitol said to be eyeing RBS Sempra's gas and power trading business

Vitol, the Swiss-based oil trading group, is believed to be negotiating the purchase of the RBS Sempra Commodities North American power and natural gas trading operation, according to sources who did not wish to be named.

RBS Sempra Commodities spokesman Mike Geller had no comment about the possible deal. Calls to Vitol's headquarters in Houston were not returned by press time.

The Royal Bank of Scotland and Sempra Energy has had up for sale the North American power and gas trading unit since mid-February, when the commodities joint venture closed on the sale of roughly half of its trading operations to JPMorgan Chase for $1.7 billion. In that deal, JPMorgan bought RBS Sempra's metals and oil and oil products trading operations.

RBS, which has a 51% holding in the joint venture, has been ordered by the European Union in Brussels to divest itself of its holding.

Sempra Energy says it wants out of power and natural gas trading and wants to see a sale of the remaining operations before year end.

There are an estimated 600 people at RBS Sempra connected with power and natural gas trading in Stamford, Connecticut. At one point, analysts had estimated the value of the North American power and gas trading books and operations at roughly $2 billion.

For the past two months, the names of a number of other big commodity trading houses, all but one also Swiss-based, emerged in connection with RBS Sempra, including Trafigura, Mercuria Energy Group, Gunvor International, and Hong Kong-based Noble Group.

However, two sources who are close to the power trading industry now say that it is Vitol that has spent time in Stamford recently, apparently discussing a purchase and sale agreement with RBS Sempra.

An RBS spokesman in London said he was unable to comment one way or the other on whether Vitol was involved in any talks.

The RBS Sempra Commodities joint venture was put together in early 2008 to have the Royal Bank of Scotland provide collateral to Sempra's trading books.

Vitol, privately owned by its employees, was founded in 1966 and is based in Geneva with offices in Houston, Singapore, Rotterdam, Moscow and London. The company has 830 people working in its trading and exploration and production businesses, globally, and 775 people are employed by a terminals company.

In 2009 the firm had revenues of $143.3 billion, with about $100 billion coming from the buying and selling of crude oil and petroleum products. It said that in 2009 it had $12.6 billion in revenue from buying and selling natural gas and $4.5 billion in revenue from buying and selling liquefied natural gas.

While the company offers no revenue numbers for power trading in 2009, it says that it traded 200 million terawatt hours of power in the UK, France and Germany last year.

In a statement on its web site about its power trading business in the US, Vitol says it has been active "in trading power forwards and options in the eastern states." — *Jeffrey Ryser*

Google makes its first direct investment in renewable energy, $38 mil with NextEra

On April 30, Google made its first direct investment in a utility-scale renewable energy project, taking a $38.8 million stake in two operating wind farms in North Dakota owned by NextEra Energy Resources.

Google's investment is in the form of a tax equity stake in NextEra's Peace Garden Wind Funding LLC, which owns the 120-MW Ashtabula-2 wind farm in Barnes County and the 49.5-MW Wilton Wind-2 wind farm in Burleigh County.

NextEra said it sold a total of $190 million of Class B membership interests in Peace Garden, but it did not reveal the names of the other investors. Google made the announcement on a blog post on its own web site.

NextEra said it intends to use the proceeds from the sale to reimburse, in part, capital contributions made by NextEra to develop and build the wind facilities.

In the past Google has made investments in early stage renewable energy companies such as eSolar and AltaRock, but the NextEra investment represents the Internet company's first direct investment in a renewable energy project.

Google said it is now moving that strategy to include funding for utility-scale projects that can "accelerate the deployment of renewable energy" while providing attractive returns.

A related company, Google Energy, in February received market-based rate authority from Federal Energy Regulatory Commission, which will enable the firm to buy and sell wholesale power supplies for its parent company (*GPR*, 25 Feb, 29).

In its FERC filing, Google Energy said it sought the authority in order to have the ability to buy and sell power on the wholesale market to have more flexibility in procuring renewable energy and to take advantage of competitive wholesale power markets. — *Peter Maloney*

FINANCE

Energy Secretary Chu says DOE needs $9 billion more in nuclear loan guarantees

Energy Secretary Steven Chu last week 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.

In February, DOE awarded Southern Company and two partners an $8.3 billion loan guarantee for a nuclear expansion project in Georgia. That leaves DOE about $11 billion in loan guarantee authority for nuclear plants and another $2 billion for uranium-enrichment projects.

"If you want to capture all three that would be an additional $9 billion," Chu said during a hearing of the Senate Appropriations Subcommittee on Energy and Water Development.

Chu said that two projects are ready to go and a third will likely be ready before fiscal 2011, which begins in October. The department would only need an additional $4 billion in loan guarantee authority to go forward with the two that are currently closest to receiving awards, Chu said.

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.

While Byron Dorgan, a North Dakota Democrat who chairs the subcommittee, did not explicitly say he would pursue the increased loan guarantee authority before the fiscal 2011 appropriations, he did say that he was interested in helping the administration. He also said that several supplemental spending bills that will likely move through Congress before the annual appropriations could be used to increase DOE's loan guarantee authority.

Louisiana Senator Mary Landrieu, a Democrat who sits on the subcommittee, said that she would support the additional authority for DOE, and would work closely with Dorgan to push that increased loan guarantee authority.

Loan guarantees for nuclear power-plant projects also have wide support from Republicans in Congress. — *Derek Sands*

Energy Future Holdings earns $355 million in first quarter, down 20% from a year ago

Energy Future Holdings on May 4 posted first quarter earnings of $355 million on revenue of $1.999 billion, compared with earnings of $442 million on revenue of $2.139 billion in the same period last year.

EFH is co-owned by Kohlberg Kravis Roberts & Co., TPG Capital, and Goldman Sachs Capital Partners. It owns Texas generator Luminant Energy, electricity retailer TXU Energy, and 80% of transmission and distribution utility Oncor Electric Delivery.

EFH said in a 10-Q filing to the Securities and Exchange Commission that its first quarter earnings included $639 million in after tax, unrealized commodity-related mark-to-market net gains largely related to positions in EFH's long-term hedging program, and a $9 million debt extinguishment gain resulting from a first quarter 2010 debt exchange.

Those gains were partially offset by $70 million in unrealized mark-to-market net losses on interest rate swaps and $8 million of increased net cost recorded as a result of the health care legislation enacted by Congress in March.

Paul Keglevich, executive vice president and CFO at EFH, said the company's available liquidity — a key concern, given the $1.4 billion in debt that will come due over the next four years and the more than $20 billion that will come due in 2014 — totaled $4.183 billion as of March 31. That total includes $2.421 billion from a $2.7 billion revolving credit facility, $434 million from a $1.25 billion letter of credit facility, and $1.328 billion in cash and equivalents.

Keglevich noted that EFH again has elected to issue new debt rather than pay interest in cash on some of its senior debt this November in an effort to maximize its liquidity. EFH has used this "payment-in-kind" or PIK option for dividend payment several times since it acquired the old TXU Corp. in October 2007. — *Housley Carr*

ASIA/PACIFIC RIM

India's Essar Energy cuts IPO price after Greek crisis causes market volatility

The volatility in the global financial markets following the financial crisis in Greece has forced Indian power developer Essar Energy PLC to cut the price of its initial public offering. The company last week sold 303 million new shares at $6.04 each compared with the earlier indicative price range of $6.86 to $8.39 a share.

At the revised price, the company is likely to raise $1.83 billion, which is lower than the originally planned $2.5 billion. The Essar offering was the largest primary share offering on the London Stock Exchange since December 2007.

Prashant Ruia, vice chairman of Essar Energy said the company decided to reduce the offer price taking into consideration the changed market conditions and also because it was the company's "debut offering."

The shares start trading on the London Stock Exchange on May 4.

Essar Energy, which owns power plants totaling 1,220 MW, plans to use the proceeds from the IPO increase its installed capacity to 11,470 MW by 2014.

The IPO reduced the Ruia family's stake in Essar Energy to 75% from 100%.

Essar Energy said in the first phase of its expansion it would build six coal-fired power plants totaling 4,880 MW that are scheduled to begin operating between 2010 and 2012. In the second phase, it would build six more coal plants totaling 5,370 MW that would enter service between 2013 and 2014.

JP Morgan Cazenove and Deutsche Bank were the joint book runners of the IPO.

Essar Energy is one of several Indian power companies raising money from overseas investors. In 2009, Tata Power Co. raised $335 million by issuing global depository receipts to overseas investors while Sterlite Industries Ltd. and Suzlon Energy Ltd. raised $1.5 billion and $108 million, respectively, by selling shares in the global equity markets. Sterlite Industries, through its subsidiary Sterlite Energy Ltd., plans to develop power projects totaling 10,000 MW over the next five years. — *S. Anuradha*

Bangladesh launches first-ever tender for renewable projects totaling 207 MW

State-owned Bangladesh Power Development Board last week launched its first renewable energy tenders, inviting bids from private and foreign investors to develop wind and solar power projects totaling 207 MW.

An official associated with the bidding process said BPDB has invited bids for a 200-MW wind project near Chittagong and for three solar power projects totaling 7 MW. These include the 1-MW Rajshahi, the 3-MW each Rajbarihat and the Sarishabari solar power projects. All four projects are to be developed on a build-operate-own basis.

Investors in the wind power project have to submit the bids by June 21, and BPDB plans to announce the winner by December. The winner has to build the power plant within 18 months of winning the contract.

For the solar power projects bids must be submitted by May 23. BPDB plans to award the projects by October 2010 and the winners must start operating the power plants by June 2011.

BPDB plans to buy the output from the wind power plant for 25 years and from the solar power plants for 15 years.

At present, renewable energy comprises less than 1% of the country's installed capacity of 5,300 MW. The government plans to increase this to 5% by 2015 and to 10% by 2020.

The severe power shortage in the country has prompted BPDB to launch a series of tenders to enable private and foreign companies to develop power projects. In early April BPDB launched the tender for three oil-fired independent power projects totaling 250 MW. Interested parties can submit their applications by May 27 and the projects are likely to be awarded by December 2010. — *S. Anuradha*

Australian government puts on hold legislation to reduce CO2 emissions

The Australian government last week postponed to 2013 plans to introduce the Carbon Pollution Reduction Scheme because of the likely opposition in parliament.

Prime Minister Kevin Rudd said the plans for the CPRS were on hold after they failed to pass through parliament. The parliament had rejected the scheme twice in 2009 and the government planned to introduce the bill again in parliament in the first quarter of 2010. The opposition parties have rejected the CPRS on the ground that it would push up the costs for power companies, coal miners and electricity consumers.

Under the proposed CPRS, Australian power companies would be required to reduce their carbon emissions by 5% by 2020. The Australian government planned to issue one-year fixed period carbon permits at $7.60/ton in 2011 and full trading of the permits was to start in July 2012.

"The opposition decided to back flip on its historical commitment to bring in a CPRS, and there has been slow progress in the realization of global action on climate change. These two factors together inevitably mean that the implementation of a Carbon Pollution Reduction Scheme in Australia would be delayed," Rudd said, adding that the government would meet its commitment to reduce carbon emissions by 5% by 2020.

The government did not say when it would reintroduce the CPRS legislation but analysts said a decision would be taken only after the general elections in late 2010. As a result the CPRS can be launched at the earliest by 2013.

Sajal Kishore, director at Fitch Ratings, said the postponement of the CPRS should not affect investments in the renewable energy sector because the Australian government is already implementing the Renewable Energy Target under which 20% of the country's energy would come from renewable sources. "At this stage no new coal-fired projects have been announced and the renewable build up will continue to happen under the Renewable Energy Target," Kishore said.

Renewable energy company Pacific Hydro though said it was "bitterly disappointed" at the postponement of the CPRS. "It is an opportunity lost for Australia to commence the transition to a low carbon economy that many of our key trading partners have embarked upon."

Pacific Hydro said with the postponement of the CPRS, the RET was the only tool for Australia to reduce carbon emissions. "The 20% RET is now the only game in town that will drive any meaningful change to the way we generate energy over the coming decade and gives us any chance of meeting our emissions reduction commitments."

The CPRS is part of Australia's strategy to reduce the country's greenhouse gas emissions. Australia has the second-highest level of carbon dioxide emissions per capita among the developed countries.

The last available data from the government indicates that Australia emitted 576 million tons of carbon dioxide equivalents in 2006 compared with 547 million tons in 1990. The energy sector was the largest source of greenhouse gas emissions comprising 69.6% of all emissions. — *S. Anuradha*

Seven investors pre-qualified to bid for 2,000-MW Indonesian project

Seven investor groups have been pre-qualified to bid for the 2,000-MW Pemalang coal-fired plant in Indonesia, an official associated with the auction said last week. The investors include China's Shenhua Energy, Marubeni Corp., Mitsubishi Corp., Korea Electric Power Corp., a consortium of China National Technical Import Export Corp. and Guangdong Yudean Group, a consortium of France's GDF Suez and Japan's J-Power, and a consortium of Japan's Mitsui & Co. and UK-based International Power PLC. The $3 billion build-operate-transfer Pemalang project in central Java is part of the second 10,000-MW fast track program announced by the Indonesian government in 2010.

The successful bidder has to sign a 25-year power purchase agreement with the state-owned power utility Perusahaan Listrik Negara. The winner of the project would be announced in September and the plant is scheduled to begin operations in May 2015.

Under the second fast track program, 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 with the rest from coal-fired plants. Of the total capacity planned, approximately 5,000 MW would be built in the Java and Bali islands while the remaining capacity in the other islands. The plants will be built between 2010 and 2014, and the entire program would require an investment of $10 billion.

The first 10,000-MW fast track program was announced in 2007 with PLN as 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*

Philippine agency says Korea Water Resources is the highest bidder for 246-MW hydro facility

The Philippine privatization agency last week declared Korea Water Resources Development Corp., the highest bidder for the 246-MW Angat hydropower plant with a bid price of $440.8 million.

Power Sector Assets and Liabilities Management Corp. said K-Water's offer was the highest among the six bidders. First Gen Northern Energy Corp. offered $365 million, San Miguel Corp.

offered $312.50 million, SN-Aboitiz Power Pangasinan Inc. bid $256 million, Trans-Asia Oil & Energy Development Corp. offered $237 million, and DMCI Power Corp. bid $188.89 million.

PSALM said K-Water's bid exceeded the reserve price, but it did not mention the price. PSALM said the good response for the auction negated the "misconceptions thrown against the bidding process."

Some analysts were of the view that the response to the auction would not be very good because the new owner of the power plant does not get full control over the Angat dam that supplies water to the plant. The new owner of the Angat plant has to operate and maintain the dam at no cost to the government. However, the use of the water would be regulated by the National Water Resources Board. The Angat dam supplies more than 90% of the water requirements of Manila and neighboring provinces.

South Korea-based K-Water is a state-owned company and owns power plants totaling 1,000 MW. The Angat plant is its second overseas project it has won. In 2009, it won the bid to develop the 150-MW Patrind hydropower project in Pakistan.

K-Water's bid for the Angat plant translates into $1.8 million/MW, which is higher than analysts' expectations that bidders would pay around $1 million/MW for the plant. In the past, investors paid between $1.16 million/MW and $1.48 million/MW for hydropower assets sold by PSALM.

An analyst at Macquarie Research Equities said K-Water may have preferred to bid at a high price because it wanted to enter the Philippine market and on optimism that wholesale electricity prices are likely to remain high in the Luzon grid where the Angat plant is located. The analyst said the bids of SN-Aboitiz Power and Trans-Asia Oil were "more reflective of the local sentiment."

Located in Bulacan, the Angat hydropower plant comprises four main 50-MW units, three 6-MW units, a 10-MW unit and an 18-MW unit. The plant was commissioned between 1967 and 1968.

Angat is the first National Power Corp. plant to be auctioned in 2010. It is also the first major hydropower plant to be auctioned after the auction of the 175-MW Ambuklao-Binga hydropower complex in November 2007.

A consortium of Aboitiz Power and SN Power won Ambuklao-Binga with a bid of $325 million. In December 2006, PSALM sold the 360-MW Magat hydropower plant to a consortium of Aboitiz Power and SN Power for $350 million and the 112-MW Pantabangan-Masiway hydropower complex to First Generation Hydropower Corp. in September 2006 for $129 million. — *S. Anuradha*

Philippine privatization agency PSALM selects San Miguel to assume PPA of 1,200-MW plant

The Philippine privatization agency has declared San Miguel Corp. the highest bidder at the auction to select an investor to assume the offtake contract and the eventual ownership of the 1,200-MW Ilijan independent power plant.

The privatization agency, Power Sector Assets and Liabilities Management Corp., in mid-April said San Miguel offered $870 million for Ilijan. The next highest bidder was Trans-Asia Oil and Energy Development with a bid of $804.4 million. First Luzon Power Corp. offered $534.1 million, and Therma Power Visayas Inc. bid $100 million.

Located at Batangas in Luzon Province, the Ilijan plant is operated by Korea Electric Power Corp. through its subsidiary KEPCO Ilijan Corp. under a build-operate-transfer contract that is set to expire in 2022.

Under the terms of the auction, San Miguel immediately gets the right to sell the output of the plant in the wholesale market and gets the ownership of the plant once the BOT contract expires.

With the Ilijan auction, PSALM has bid out 68.22% of the independent power producer contracts in the Luzon and Visayas grids. PSALM plans to privatize 70% of the IPP contracts in those grids.

So far, PSALM has auctioned the offtake contracts for the 345-MW San Roque hydropower plant and the 1,000-MW Sual coal-fired plant to subsidiaries of San Miguel, the contract for the 100-MW Bakun-Benguet hydropower plant to Amlan Power Holdings Corp., and the contract for the 700-MW Pagbilao plant to Therma Luzon Inc. Both Amlan Power and Therma Luzon are subsidiaries of Aboitiz Power Corp. In April PSALM launched the auction of the offtake contract of the 650-MW Malaya coal-fired plant. — *S. Anuradha*

EUROPE

Vattenfall starts building wind farm project, 150-MW, in Irish Sea, for 2011completion

Swedish company Vattenfall said this week it has started building the 150-MW Ormonde offshore wind farm in the Irish Sea.

It is the third construction start by Vattenfall of wind capacity in the UK in the last 18 months, the company said, with work proceeding at the 300-MW Thanet wind farm off the coast of Kent in southern England and the 41.4-MW Edinbane onshore wind farm on the Isle of Skye, Scotland.

"The Ormonde Offshore Wind Farm had its first foundation piles installed at the weekend," said Anders Dahl, the company's head of wind power. "Construction is due for completion during 2011 and first power is expected later that year," he said.

The Ormonde site is 10 kilometers off Barrow-in-Furness, Cumbria, north western England. The wind farm will host 30 RePower 5-MW wind turbines, "sufficient to supply approximately 100,000 homes with clean electricity annually," Vattenfall said.

The company said the project was helping employment in the UK, with Fife-based Burntisland Fabrications supplying the steel platform and steel jackets and Harland & Wolff supplying logistic and assembly services. The control, operations and maintenance base will be built in Barrow port. — *Henry Edwardes-Evans*

Morgan Stanley plans to acquire 265-MW stake in German coal plant

Morgan Stanley Capital Group plans to buy 265 MW of capacity at the Veltheim coal-fired plant in Lower Saxony, Germany, that is currently owned by E.ON.

No value was put on the deal, which completes an agreement E.ON reached with the European Commission to divest assets in order to reduce its market dominance in the German power market.

"The transaction has already been approved by the EU Commission," E.ON said.

The 786-MW Veltheim plant is on the north side of the Weser in the district of Wolfenbuttel, Lower Saxony. It is owned 66.6% by E.ON Kraftwerke and 33.3% by Stadtwerke Bielefeld.

Unit I was decommissioned in 2000. Units II (93-MW) and III (303-MW) are fired with hard coal, and unit IV (390-MW) is run as a gas-fired combined-cycle unit. According to E.ON data, the power station generates electricity for the mid- to peak-load range with a yearly power generation of around 2.2 TWh.

In late 2008, E.ON committed itself to divest 5,000 MW of capacity in Germany and its extra-high voltage grid. The grid was sold in 2009 to TenneT of the Netherlands. Power station capacity has either been sold to various European competitors, including EDF, GDF Suez, Statkraft and Verbund, or swapped for capacity in France and Belgium. — *Henry Edwardes-Evans*

Middle Eastern briefs

- Israel's **Public Utilities Authority (Electricity)** has granted a 20-year production license for a 48-MW gas-fired project planned by **Mashab** at Ramle in central Israel. The company is jointly owned by IDB Development and Irish building company CRH.

Announcing the license, the PUA said that electricity generation by private power producers stands at 520 MW, with provisional licenses granted for 1,600 MW.

- **Rapac Communications and Infrastructure** has signed a memorandum of understanding with **Dalkia**, a subsidiary of France's Veolia Environment, to build and operate a 400-MW private power plant in central or southern Israel. The parties expect to finalize their agreement within 120 days, and have agreed to seek a third partner for the project.

Rapac will establish the power plant, while Dalkia will operate and maintain it.

NORTH AMERICA

PROJECTS

Mississippi Power's 582-MW IGCC project appears to be dead after PSC rules against it

Mississippi Power's proposed 582-MW integrated gasification combined-cycle project appears to be dead, despite the Mississippi Public Service Commission's ruling late last week that the project could proceed if the utility agreed to a $2.4 billion cap on recoverable project costs.

"The commission conditions seem to make it impossible for Mississippi Power to finance or construct the Kemper County IGCC project," said Mississippi Power spokeswoman Cindy Duvall. "We are disappointed in this decision."

In its 2-1 ruling, issued on April 29, 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.' While the physical project itself, in concept, could benefit [Mississippi Power's] ratepayers, the proposal's many uncertainties and risks, concerning technology, cost and performance, given [the utility's] insistence that these uncertainties fall largely on ratepayers, are too high."

The commission added, however, that while it has "no statutory obligation to help a petitioner convert a rejected project into an approved one," it has chosen to offer conditions that Mississippi Power must accept within 20 days if the IGCC project is to advance.

Most important, the PSC said that the project's recoverable costs should be capped at $2.4 billion. That amount is equal to Mississippi Power's current cost estimate of $2.695 billion minus the utility's expectation of $295 million in federal, state and local incentives, but is $800 million less than the $3.2 billion "hard cap" that the utility recently proposed.

The commission said that the $2.4 billion cap could be raised, but only if Mississippi Power proves that the increase would be at least fully offset by operational efficiencies or other savings. It also insisted that the utility agree to pay for independent monitors the PSC would hire to oversee various elements of the project.

The PSC noted that it would determine later whether to approve a request by Mississippi Power for ongoing recovery of the project's financing costs, assuming that the utility accepted the PSC's conditions.

PSC Chairman Brandon Presley, who opposed the ruling, said in a written dissent that while he appreciates the two other commissioners' efforts to minimize the project's risks, the ruling's conditions do not sufficiently protect the ratepayers of Mississippi Power. Presley said that other options exist that involve les risk to ratepayers.

Calpine, Entegra Power Group, KGen Power, Kelson Energy and other generators have expressed interest in meeting Mississippi Power's incremental needs through their existing gas-fired plants in the Lower Mississippi Valley.

Calpine spokeswoman Norma Dunn declined to comment specifically on the PSC's Kemper ruling, stating only that "we have power plants in this area and we look forward to continuing to supply power to the area."

The PSC determined last November that due to many variables, including how much existing Mississippi Power-owned capacity should be retired over the next few years for economic and environmental reasons, the utility's incremental needs in 2014 will range from 304 MW to 1,276 MW.

The commission said then that "substantial evidence exists in the record" to support Mississippi Power's plan to retire a total of 350 MW of older natural gas-fired capacity at its Watson and Eaton power stations in 2012 and 2013. It also said that under several scenarios for federal climate change legislation and carbon costs, it may be cost effective for the utility to retire up to 982 MW of older coal-fired capacity at its Greene County and Watson stations.

On May 4 Mississippi Power said that it plans to ask the PSC to reconsider its April 29 decision. Mississippi Power spokeswoman Cindy Duvall said that the motion for rehearing and reconsideration will contain a brief on why the conditions in the order would not allow the company to act in a fiscally responsible manner." It will also include an update on the parameters of the project, as well as alternatives for the commission to consider. *— Housley Carr*

National Wind and KRS Energy team up to develop 300-MW Texas wind project

National Wind and KRS Energy said April 29 that they plan to jointly develop a community-owned wind farm of up to 300 MW in Randall County, Texas.

The co-owners of the project's first 150-MW phase plan to include 12 local families who will lease a total of 14,500 acres for the wind farm, which will be named Buffalo Wind Energy, Travis Moen, National Wind's project developer, said. "This is a very interesting project because of its unique transmission access that provides potential to sell power into the [Electric Reliability Council of Texas] market and the Southwest Power Pool."

Typically, about 70% of National Energy's projects are owned by local sponsors, said National Power spokeswoman Erin Edholm. She said that the company is looking for additional local participants so the project can be expanded to 300 MW. The project does not yet have a power buyer, she said, adding that it would probably take "two years or so" to finance and build the wind farm.

National Wind is based in Minneapolis. The newly announced Buffalo Wind Energy project is National's first in Texas. The company focuses on the development of community-owned wind farms of 50 MW or more, and has developed several. KRS Energy is based in Centennial, Colorado. *— Housley Carr*

Progress Energy Florida delays start-up of two planned nuclear reactors, 1.1 GW

Progress Energy Florida said on April 30 that for the second time in a year it has pushed back the estimated completion date for the two 1,117-MW nuclear reactors it plans to build at a greenfield site in Levy County.

Progress said that it now plans to start commercial operation of the first of the two planned Westinghouse AP1000 reactors in 2021, and put the second unit online about 18 months after that.

Progress said that the Levy delay is tied to the utility's need to reduce capital spending recent downgrades to Progress' credit ratings in the wake of the Florida Public Service Commission's January denial of all but $132 million of the utility's proposed $499 million base rate increase, and a delay in the time line for securing a combined construction and operation license for the Levy units from the Nuclear Regulatory Commission.

The utility also cited Florida's weak economy, which has dampened electricity demand and load growth, and continued uncertainty about federal and state energy policies, including carbon regulation.

Progress initially had planned to complete the Levy units in 2016 and 2018. It announced last May that the online date for each of the units would be delayed by "a minimum of 20 months" due to the NRC's determination that excavation and foundation preparation work originally scheduled to be completed while Progress is seeking a construction and operation license for the plant will not be authorized until the NRC actually issues the COL.

Progress had expected the COL to be issued in late 2011 or early 2012, but the utility last week said that it now expects the license to be issued in late 2012. It also announced that it has decided to postpone any major work related to Levy until after the federal licensing is complete. Progress spokeswoman Cherie Jacobs said that includes "some design work, land acquisition for transmission lines, transmission line work, and construction of a nuclear training facility."

Progress also updated Levy's estimated cost, including land, two Westinghouse AP1000 nuclear units, transmission lines, fuel and financing, to a range of $17.2 billion to $22.5 billion. Its previous estimate was a flat $17.2 billion. *— Housley Carr*

FP&L delays start-up of two nuclear units, 2,200 MW, citing forecast drop in demand

Florida Power & Light will delay bringing online two new nuclear reactors because of lower projected electric demand, a decline in natural gas prices and schedule problems for the construction of new reactors in Europe, CEO Armando Olivera told investors this week.

The commercial operation dates of the two planned new 1,100-MW reactors at FP&L's Turkey Point site in south Florida have been adjusted to 2022 and 2023, from earlier estimates of 2018 and 2020, Olivera said.

FP&L had said the earlier targets were flexible. FP&L had slowed development of the two units after Florida regulators gave it a smaller-than-requested rate increase earlier this year.

The delay will likely increase the total cost of the two units beyond the original estimate of between $12 billion and $18 billion, Olivera said.

The company's 10-year electricity demand estimates have declined because of the recession and energy efficiency, he said. Lower natural gas prices mean nuclear generation is "less attractive," he added.

Delays for reactors being built in Finland and France — although they are a different design than FP&L has picked — have also made the company re-think its plans, he said.

"We've always said we're comfortable not being in the first wave of new nuclear" construction, Olivera said.

FP&L will continue to pursue combined construction permit/operating licenses from the Nuclear Regulatory Commission for the two new nuclear units, Olivera said.

An NRC delay in approving the design certification for the

Westinghouse AP1000 reactors planned for Turkey Point was another factor in the decision to slow development, he said. NRC is reviewing a modified shield building design submitted by Westinghouse in 2009. *— William Freebairn*

Deepwater Wind considers relaunching its 28-MW project off Rhode Island coast

Deepwater Wind said April 29 that it stands ready to resurrect its 28.8-MW offshore wind project in Rhode Island if new legislation wins approval that could restore its rejected power purchase agreement.

The project's future looked dim in late March when the Public Utilities Commission voted down its power purchase agreement with National Grid, saying that output from the Block Island wind farm is too expensive at 24.4 cents/kWh beginning in 2013.

The project has been cited frequently as a benchmark against what Cape Wind's output may cost. Cape Wind is also in negotiations with National Grid for a power purchase agreement. Massachusetts officials have said they want to see Cape Wind priced lower than the Rhode Island project.

But five state senators last week filed a bill that would take away the commission's jurisdiction over the PPA and instead place it in the hands of four state agency heads.

The bill is backed by Governor Donald Carcieri, who strongly criticized the commission's decision to reject the contract. Carcieri has been pushing offshore wind as a way to help revive the state's failing manufacturing sector.

The legislation was filed the same day that the 468-MW Cape Wind, an offshore wind project in neighboring Massachusetts, won its final federal approval (*GPR*, 29 April, 1).

The Deepwater Wind contract had set a bundled price for energy, capacity and renewable energy certificates of \$235.75/MWh for 2012, subject to an escalation factor of 3.5% each year. The price increased to \$244/MWh (or 24.4 cents per kWh) in 2013, which was expected to be the wind farm's first full year of operation.

In contrast, National Grid forecast that Rhode Island's electricity prices will be \$100/MWh to \$150/MWh from 2012-2031. In all, the contract would cost \$700 million during its 20 years, which is \$391 million more than the forecasted market price for energy, capacity and RECs, according to the utility.

In addition to the 28.8-MW project, Deepwater also has proposed a larger 106-turbine wind farm 15 miles off the coast of Rhode Island. That project is in early development. *— Lisa Wood*

Ohio EPA seeks to dismiss challenge to permit for SunCoke's 50-MW project

The Ohio Environmental Protection Agency is asking another state agency to dismiss a challenge to an air permit for a \$360 million SunCoke Energy project, including a new coke plant and an approximately 50-MW cogeneration facility in Middletown.

Ohio EPA director Chris Korleski said in the late April filing with the state Environmental Review Appeals Commission that the appeal by the city of Monroe and several individuals is "moot" because a new source review permit issued by Ohio EPA to SunCoke earlier this year "supersedes" a previous approval for the project.

Construction got under way April 12 on the long-delayed project. SunCoke, a subsidiary of Sonoco of Philadelphia, Pennsylvania, estimates the project will be completed in 15 to 18 months, meaning the coke and cogen plants could be operational in the third quarter of 2011. *— Bob Matyi*

Kentucky authority grants permit for 50-MW biomass plant in Perry County

Lexington start-up company EcoPower Generation LLC has obtained a final air permit from the Kentucky Division for Air Quality for a 50-MW biomass plant to be built north of Hazard in Perry County.

The permit now goes to the US Environmental Protection Agency for a 45-day review.

Gary Crawford, president of and CEO of EcoPower, said in an interview the company hopes to receive final approval from the Kentucky State Board on Electric Transmission and Generation Siting later this month for a \$200 million transmission project to connect the plant. EcoPower is moving forward with a system impact study at PJM Interconnection. "We hope to have that done in the third quarter," Crawford said.

Then, the company intends to negotiate a final engineering-procurement-construction contract and sign an off-take agreement for the power.

Construction could get under way in 2011 with the plant up and running in 2013. *— Bob Matyi*

SOLICITATIONS

NYPA reports solid response to solicitation for 100 MW of distributed solar photovoltaics

The New York Power Authority said last week that it received an overwhelming response, 43 proposals, to its solicitation issued in January seeking 100 MW of distributed solar photovoltaic projects.

The solicitation represents the largest solar initiative in New York's history. Once installed, the projects will increase solar energy in the state fivefold.

NYPA intends to purchase the power from the roof- and ground-mounted installations under 20-year contracts. The solar projects will be installed at schools, state and local government facilities, and municipal and rural electric cooperative systems.

The solar initiative is intended to move the state closer to Governor David Paterson's goal of meeting 45% of the state's electricity needs through renewable energy or energy efficiency by 2015.

NYPA expects to select preliminary winners by the summer. It is evaluating proposals based on price and other factors, such as a bidder's record developing, owning and operating solar. The authority also is evaluating how well bidders identify and attract host sites in targeted locations and how much they use local materials and labor.

NYPA expects to award winning contracts at its board's September meeting. — *Lisa Wood*

NStar issues RFP for RECs; responses are due by May 7

NStar on April 30 issued a request for proposals seeking renewable energy certificates. Responses will be due May 7.

NStar notes in the RFP that it is looking to purchase New England Power Pool Generation Information System certificates in compliance with the Massachusetts renewable energy and alternative energy portfolio standards.

The company is seeking RECs generated in 2009, and NStar said it may purchase up to 187,000 RECs.

Questions about the solicitation should be directed to David Simek at 781-441-8336 or William Hass at 781-441-8011. The RFP is available at: www.nstar.com/business/energy_supplier/. — *Staff Report*

DESC issues solicitation for power, services for NASA center in Texas

The Defense Energy Support Center has released a request for proposals that seeks electricity and ancillary services for the National Aeronautics and Space Administration's Johnson Space Center in Texas.

The approximate quantity of supplies being sought is 391,172 MWh, with technical data due June 9. The center is located in Houston.

The DESC is seeking offers for a 24-month delivery period (meter read date January 2011 through the meter read date January 2013) or a 36-month delivery period (meter read date January 2011 through the meter read date January 2014) for all accounts. Only one delivery period will be awarded.

The RFP contact is Jezabel Aviles, jezabel.aviles@dla.mil, 703-767-2394. — *Staff Report*

Defense Energy Support Center issues solicitation for Texas DOD facilities

The Defense Energy Support Center on April 28 issued a solicitation for the supply of electricity and ancillary services for various Department of Defense and federal civilian agencies located in Texas.

The approximate quantity being sought under the solicitation is 1,703, 567 MWh and technical data is due June 9. Pricing will be determined at a later date.

The delivery period for all accounts is 24 months (meter read in January 2011 through meter read in January 2013). Supplies are being sought for various accounts, including for Customs and Border Protection, Dyess Air Force Base and the Naval Air Station in Kingsville.

Questions should be directed to Bryan Simmons, 703-767-8531, bryan.simmons@dla.mil or Jezabel Aviles, 703-767-2394, Jezabel.Aviles@dla.mil. — *Staff Report*

TransAlta plans June auction to sell four years' supply of Alberta power

Calgary, Alberta based TransAlta on May 4 said that it will be hosting a fixed price power auction on June 15 where it will be selling a four-year strip of Alberta power.

TransAlta held its first two power auctions in 2009, which it said attracted Canadian industrials, banks and trading companies.

The auction will be facilitated by World Energy Solutions, an operator of online exchanges for energy and green commodities.

Auction inquiries should be sent to Cory St. Croix, senior originator, 403-267-6929, cory_stcroix@transalta.com.

For additional details, go to www.transalta.com/investor-centre/events-presentations/upcoming-events/2010-06-15/alberta-fixed-price-power-auction. — *Staff Report*

WAPA seeks to buy renewables certificates for National Renewable Energy Laboratory

The Western Area Power Administration on April 28 said that it is looking to purchase renewable energy certificates on behalf of its sister agency, the National Renewable Energy Laboratory.

In the request for proposals, Western is seeking 355 MWh of RECs, per year for 10 years and an additional 1,235 MWh per year for two years for the Department of Energy's Golden Field Office.

Offers must be for firm, fixed, per-MWh unit price for each year of the contract term. Proposal selection will be based on best value, WAPA said. Proposals are due May 14.

The RFP is available at: www.wapa.gov/ugp/powermarketing/RenewEnergyCert/2010REC.htm.

A second RFP to purchase RECs for multiple federal agencies may be released later this year, WAPA noted. — *Staff Report*

WHOLESALE MARKETS

Southwest Power Pool's capacity margin hit 42% in 2009, says the state of market report

The Southwest Power Pool's capacity margin hit 42% in 2009, according to the annual State of the Market Report delivered last week by Boston Pacific, the grid operator's independent market monitor.

The SPP had 67,796 MW of capacity in 2009, while peak demand was just 46,482 MW, representing 42% of load, compared with a 2008 resource margin of 35% of load.

Boston Pacific President Craig Roach noted that the report shows that after subtracting operating costs, power prices in the SPP Energy Imbalance Service market were not enough to cover the annualized fixed costs of building a new gas combustion turbine peaking unit or intermediate-load combined-cycle plant.

The SPP Energy Imbalance Service market average price was \$27.50/MWh in 2009, compared with \$53.21/MWh in 2008, a 48% drop. The precipitous drop in natural gas prices in 2009 combined with the recession accounts for much of the decline, but the addition of three new Nebraska entities to the market in April 2009, and the nuclear power units that serve those entities, also contributed to the price decline.

Roach noted that the comparable average prices in the Midwest Independent Transmission System Operator and Electric Reliability Council of Texas footprints were $27.11/MWh and $30.19/MWh, respectively.

The new Nebraska entities in the SPP are the Lincoln Electric System, the Nebraska Public Power District and the Omaha Public Power District. In September, Missouri Public Service joined the EIS market, and Independence Power & Light, also in Missouri, joined the EIS market in December.

After subtracting the 4,556 MW of capacity in the generation interconnection requests that transitioned to SPP when the Nebraska entities joined SPP, the capacity in the queue declined from about 60,000 MW at the end of 2008 to about 56,212 MW at the end of 2009, a drop of about 6%. That is after almost doubling between 2007 and 2008.

Excluding the Nebraska entities, the SPP EIS market peak demand declined by 6.8% in 2009, compared with 2008, and electricity usage for all of 2009 fell by 2%, compared with 2008. To put that in perspective, the Energy Information Administration reports that electricity usage across the nation fell by 3.1% in 2009.

The load-weighted average hourly price for any entity in SPP varied from 7.2% above to 18.1% below the SPP-wide weighted average hourly price. Southwestern Public Service, in the Texas Panhandle, had the highest weighted average price at $30.75/MWh, and NPPD had the lowest, at $23.51/MWh.

Power sold in the SPP EIS market totaled 20.8 million MWh, with $556 million paid to suppliers in 2009. EIS market sales equaled about 10.6% of total electricity consumption in the market footprint. In comparison with 2008, EIS market power sales were up 38%, but sales revenue was down 35%, because of the sharp decrease in prices. Excluding the entities added during 2009, EIS market MWh sales increased by 9.6% and sales revenue fell 46%. *— Mark Watson*

SPP monitoring unit finds no evidence of market disadvantage for external generators

A Southwest Power Pool Market Monitoring Unit report has dismissed concerns that certain non-SPP generators see as barriers to selling power into the SPP Energy Imbalance Service market.

But during the first 12 months of allowing external generators to participate in the EIS market, only one generator, Dogwood Energy, did so, and since then, Dogwood Energy has joined SPP as a full participant, according to a report filed last week at the Federal Energy Regulatory Commission.

SPP launched its EIS market in February 2007. In April 2008, FERC allowed SPP to accept from generators outside the EIS footprint power they offered into that market. Further, the commission ordered SPP to prepare, 12 months after the date when outside generators could enter the market, an analysis of the effectiveness of external generation in increasing the depth of the EIS market. That effective date for outside entrance was February 2009. The report covers February 2009 through January 2010.

Allowing external generators to participate had "negligible impact" in adding depth to the EIS market, and SPP's dispatch caps did not limit external generator participation, the report concludes. A dispatch cap is a limit on any one generator's ability to inject power into the market. SPP has one cap for the entire region — typically close to 2,000 MW on any one day — plus lower caps for individual utility zones, also known as balancing authorities, which can be as small as 65-MW.

"Although there is potential for the exercise of market power by balancing authorities in all external generator implementations, we have not been informed of such during our research," the report states.

From June 2009 through August 2009, Dogwood Energy, a 660-MW gas-fired plant in Pleasant Hill, Missouri, southeast of Kansas City, participated as an external generator via a connection with Kansas City Power and Light. On September 1, 2009, Dogwood Energy joined the SPP EIS market as a full participant.

"When asked if they experienced any barriers to entering the EIS market as an external generator, the Dogwood representative stated that they encountered some minor operational issues due in part to pushing an aggressive time line to enter the market," the report states. The Dogwood Energy representative interviewed by the MMU said the issues were resolved quickly, the report states.

The report speculates that the expansion of the SPP footprint, including 10 entities in 2009, may mean that certain generators that could have participated as external generators have instead entered as full participants.

Another reason for the lack of EIS market participation by external generators may be low power prices and a lack of incentive to supply that market, versus others nearby, such as the Midwest Independent Transmission System Operator.

Several external generators "expressed concerns about entering the SPP EIS market as an external generator," the report states. For example, two parties said the process for participating is "cumbersome."

"However, the MMU finds that these concerns are perceived barriers rather than actual barriers," the report states. "Since the interested parties expressing these opinions never attempted to join the EIS market, they have no direct experience with the external generator process. Also, the single external generator that did participate in the EIS market expressed overall satisfaction with their experiences." *— Mark Watson*

FERC tells NYISO its must continue to offer NITS transmission service

Federal energy regulators on April 27 rejected a request by the New York Independent Transmission System Operator to eliminate a certain type of transmission service the ISO said is "superfluous" and has never been utilized.

The Federal Energy Regulatory Commission said NYISO must continue to offer the network integration transmission service, which allows a transmission customer to schedule power from a single generator to a variety of loads, or from a variety of generators to a single load, without reserving transmission service for each transaction.

NYISO in its February 26 request said that new rules being developed by the North American Energy Standards Board will require new online functionality for the transmission service that will be very expensive for it to implement. NYISO also said that it has another financial reservation-based transmission service that makes the NITS unnecessary. It said that the inclusion of the NITS was required due to FERC rules concerning the formation of the ISO that stipulated that all pro forma tariff provisions be included in the ISO tariff.

FERC in its order said that it "has required that all public utilities that own, operate, or control interstate transmission facilities to offer network transmission service, and we are not persuaded to adopt a different policy here. That customers do not currently avail themselves of NITS does not mean the service should be unavailable."

FERC also said NYISO had not supplied a cost estimate of complying with the NAESB requirements, or a timeframe in which the rules would become effective (Docket No. ER10-811).

The New York Association of Public Power had protested NYISO's proposal, saying the service was specifically required by FERC, and that NYISO could apply for a waiver of the NAESB software requirements. — *Jason Fordney*

FERC approves Cal ISO proposal to increase renewable data provision

The Federal Energy Regulatory Commission approved a proposal by the California Independent System Operator to expand the scope of data that wind, solar and small hydropower project owners must provide.

The ISO proposed to require intermittent resources with a capacity of more than 10 MW to report outages that affect more than 1 MW of their capacity.

The prior tariff required the operator of a plant to report an unanticipated forced outage that reduced the capacity of the unit by the greater of 10 MW or 5% of the unit's total value, to the extent the outage lasts longer than 15 minutes.

Lowering the threshold from 10 MW to 1 MW for outage reporting "is a reasonable means to address variability and uncertainty in eligible intermittent resource output," FERC found (ER10-319).

Also approved was Cal-ISO's proposal to require all eligible intermittent resources that have signed participating generator agreements or qualifying facility agreements with the ISO to install specific forecasting and telemetry equipment and to communicate relevant data to the ISO. The requirement currently applies to generators in the participating intermittent resource program.

The telemetry and forecasting equipment requirement will help mitigate operational challenges related to intermittent resources by increasing the quality of data Cal-ISO receives from these resources, FERC found.

The compliance filing is due within 30 days of the April 30 order. — *Esther Whieldon*

TRANSMISSION

Eastern Interconnection mulls appointments to steering committee for transmission project

The planning group working on a "big picture" planning process across the Eastern Interconnection this month will submit to the Department of Energy its proposal for the makeup of a steering committee that will guide the group's efforts.

Created with $16 million in DOE funding, the Eastern Interconnection Planning Collaborative is working to aggregate modeling and transmission expansion plans developed in regional processes into the new transmission planning effort encompassing the Eastern Interconnection.

In the current straw proposal, the group's steering committee is proposed to have 29 members, representing transmission owners and developers, generation developers, power marketers, and transmission-dependent utilities. Also holding seats will be state consumer advocates, conservation groups, and state and provincial representatives, as well as representatives from the Environmental Protection Agency and DOE.

The steering committee will guide the "open and inclusive stakeholder process," said David Whitely of EIPC at a panel discussion at the Energy Bar Association's annual meeting in Washington last week. The group is working on planning scenarios to be submitted to DOE in 2013.

"It's important that we get started to meet the time lines established by DOE for these studies," Whitely said. EIPC's task is to integrate existing regional plans and develop "potential resource futures."

Each industry sector will nominate three members to the interconnection-wide caucus to select members of the steering committee, according to the draft straw proposal, which adds that "each sector should strive to achieve diversity by including as many interests and regions as possible."

The steering committee will be tasked with developing a working charter, establishing consensus in decision-making, attending meetings and conferences, and meeting other commitments through the June 2012 time frame, the proposal said.

More information on the effort can be found at www.eipconline.com. Similar efforts are under way in the Western Interconnection and Texas. — *Jason Fordney*

TransCanada allocates capacity on 500-kV line, despite Calif. limits on out-of-state renewables

TransCanada has lined up wind developers to take 3,000 MW of capacity on a 500-kV line to be built between Wyoming and southern Nevada, where the generators can access the California market.

The project could be a first-of-a-kind power line. "It's the first time a merchant line in North America has received exclusive support from renewables," said John Dunn, TransCanada project manager.

However, a March ruling by the California Public Utilities Commission that could limit out-of-state renewables going into California is creating uncertainty for the roughly $3 billion project, Dunn said.

"[The PUC decision] has had a chilling effect on our perspective and many out-of-state generators on the market for out-of-state renewables in California," Dunn said. TransCanada, based in Calgary, Canada, needs clarity on the California market before it can commit to building its Zephyr power line project, he said.

The PUC last month adopted a renewable energy credit trading program aimed at helping the state satisfy its renewable energy goals. California has set a target of getting 20% of its electricity from renewables by 2010 and 33% by 2020, creating a major market for renewable developers across the West.

The PUC order allows utilities to use RECs to meet 25% of the state's RPS. The order effectively treats out-of-state generation as RECs, which makes the generation subject to the 25% cap, according to various parties, including TransCanada and utilities.

TransCanada wants the PUC to clarify its decision so that out-of-state renewables with firm transmission into California are RPS-compliant and not subject to limits in a California utility's RPS portfolio, according to Dunn.

Late last year, TransCanada launched open seasons on two proposed 500-kV power lines running from Montana and Wyoming to southern Nevada. The direct current power lines would deliver wind generation from some of the best wind resources in North America to utilities in the Southwest where states have renewable portfolio standards.

TransCanada finished the open season on the 1,100-mile Zephyr line last month and has allocated 3,000 MW of capacity to various "credit-worthy" wind developers, subject to finishing due diligence on the developers. The company will file a final report on the allocation with the Federal Energy Regulatory Commission by the end of May, Dunn said. TransCanada believes the line could be operating in 2015.

Meanwhile, in the Northeast, TransCanada Power Marketing is suing six Massachusetts state officials in an effort to overturn state renewable energy programs that give a preference to in-state resources.

TransCanada contends that the Green Communities Act of 2008 contains provisions that violate the Constitution's Commerce Clause by requiring utilities to enter into long-term contracts for renewable resources from generators inside Massachusetts, according to the suit filed April 16 in the US District Court for the District Of Massachusetts Central Division.

TransCanada would like to sell power to Massachusetts utilities from its 132-MW Kibby wind farm it is building in Maine for more than $300 million, the suit said. TransCanada plans to expand the wind farm by 45 MW.

Also, state law requires that utilities buy solar renewable energy credits from in-state sources, a requirement that took effect this year. "The Solar Carve-Out regulations — requiring that an eligible generator must be 'located in the Commonwealth of Massachusetts' — are discriminatory on their face," the suit said. — *Ethan Howland*

FORECASTS

Southwestern to build 168-MW plant, to sign PPAs with Calpine and for 300 MW of wind

Southwestern Public Service Co. said May 3 that a power planning process that started with three solicitations in 2008 is finally evolving into a clear power plan that will take the utility through a complicated time.

SPS, a subsidiary of Xcel Energy that serves parts of Texas and New Mexico, said in a filing posted on the Public Utility Commission of Texas' web site on May 3 that the utility plans to build a 168-MW gas-fired combustion turbine at its Jones station near Lubbock by mid-2012, to buy 200 MW of combined-cycle power from Calpine from 2012 through 2018, and to enter into power purchase agreements soon for "up to 300 MW" of wind power.

In seeking a certificate of convenience and necessity for the $106 million Jones CT, SPS noted that "at a future date, [the planned CT] may be paired with a heat recovery steam generator and steam turbine ... to create a combined-cycle generating facility."

Bennie Weeks, manager of resource planning at Xcel Energy Services, said in pre-filed written testimony to the PUC that "SPS is in a unique situation ...being generally short of capacity in the years 2010-29, but having a greater firm peak generation need in the years of 2010 through 2018 and then again in the years of 2024 through 2029. As a result of expiring wholesale contracts, SPS is actually forecasting a decline in firm peak demand it is responsible to serve, during the years of 2019 through 2023, before the general load growth on the SPS system overcomes this mid-term drop in peak demand."

To help it develop a plan to meet its up-down-and-up power needs over the next two decades, SPS in 2008 started analyzing its options, and then issued three requests for proposals. One sought to replace or expand an existing 200-MW power purchase agreement, another sought up to 250 MW of wind power, and a third sought to purchase or develop up to 600 MW of dispatchable fossil-fired capacity.

Weeks said that SPS received 16 responses to the RFP for 200 MW, 23 responses to the wind power RFP, and 24 responses to the 600-MW RFP. The utility developed "self-build" alternatives in each case to help ensure that the offers were cost-competitive.

Weeks said that a proposal by Public Service Enterprise Group to provide 600 MW from a combined-cycle plant for 15 years starting in June 2012 initially appeared to be "by far the most economic option," but that more study determined that needed transmission upgrades could not be completed before June 2013. "On July 24, 2009, PSEG provided SPS a revised, higher-priced bid, which removed them from consideration."

SPS then stepped up talks with four RFP runners-up, including Calpine, which offered 500 MW of combined-cycle power, but again transmission issues arose.

SPS spokesman Wes Reeves said the utility's next focus will be selecting the entities and wind farms from which SPS will purchase up to 300 MW of wind power. The utility will select the winner or winners from among the respondents to its 2008 wind power RFP "in the near future," he said. — *Housley Carr*

Northeastern capacity markets will continue to attract investment as planned: PJM official

Although investment in new fossil fuel-fired power generation in the organized markets appears to have dried up, the capacity markets in the Northeast are working as designed and will be able to attract new capacity against the backdrop of expected coal-fired power plant retirements, a top official with the PJM Interconnection and an energy industry consultant recently said.

"Why would anybody be building anything? We are sitting on massive surpluses," Robert Stoddard, vice president and practice leader of the energy and environment practice at Charles River Associates, said.

But according to Stoddard, the capacity markets in the Northeast are designed to react to exactly the kind of scenario in which the industry now finds itself — low demand, combined with low fuel prices, a capacity surplus and increasing state requirements for renewable energy and energy efficiency. "I have every confidence that they [the markets] will do that," he explained, adding that if regulators and utilities second-guess the market instead of just letting it work, this would bring more risk to rate payers.

New England and the PJM Interconnection have robust capacity markets, while the Midwest Independent Transmission System Operator still does not, according to Stoddard. Meanwhile, New York is looking at alternative solutions and trying to achieve a 15% reduction in energy use by 2015 instead of having to build new power plants, he said.

"In areas where we have low [capacity] prices, of course nobody will invest," Andy Ott, vice president of markets for PJM, said, adding that in areas where the grid operator really needs generation, the capacity prices are higher. According to Ott, there are a lot of different factors playing into a company's decision to build power plants today, but investment in the industry has not dried up. "I am not seeing complete silence in the generation queue," Ott said, adding that several significant traditional generation resources have been expressing interest in entering the capacity market in future auctions.

PJM's generation queue shows about 41,877 MW of proposed wind generation and around 30,759 MW of proposed non-renewable energy projects.

PJM is not overly worried about the possibility that a lot of coal units may retire because they are not recovering their costs to stay in operation. PJM's independent market monitor had identified in its annual state of the market report around 11,000 MW of coal units that could potentially choose to retire in PJM. "This is not a problem," Ott said, explaining that having certain generators retire only to be replaced by demand response and energy efficiency is not a "bad thing."

According to Stoddard, if those coal plants in fact end up retiring anytime soon or are subjected to more stringent environmental standards, this process could accelerate the time when new capacity would be needed.

Some critics have said that the capacity markets looking only three to four years ahead do not provide a sufficiently long signal for investors to build new generation. "The original design of the [PJM] reliability pricing model was four years forward," Ott explained, saying that the current three-year design was a compromise. "Developers think they can do it [in three years]," Stoddard said, adding that this time is enough to develop a peaking or smaller project, as well as demand response.

Merchant power plant projects are still possible, Stoddard said. However, according to him, the leverage financing model used in the past will not return for a long time. "If you have a long-term contract, and you can assume [the fossil fuel-fired project] is not susceptible to" carbon dioxide and other emissions restrictions, "you can find somebody to finance it," he said.

According to Stoddard, once the credit market is on firm footing again and there is a need for capacity, investment dollars in the industry will be available again. Money for some transmission projects is also available, he said.

According to PJM, in order to have a stable price in both the capacity and energy markets, the market should be allowed to operate as designed. "Stable rules are more important, frankly," Ott said, explaining that if there is stability in the rules, there is an expectation that this would lead to long-term contracts, including bilateral contracts in the market.

PJM reviews its RPM rules periodically to make sure they reflect market conditions. PJM just completed an RPM review and concluded that everything is fine, Ott said. *— Milena Yordanova-Kline*

Danish wind turbine manufacturer Vestas sees uptick in wind turbine orders, industry

Danish wind turbine manufacturer Vestas Wind Systems sees an uptick under way in the wind power industry.

Last week the company said that over the past month it had orders for 2,014 MW of wind turbines, including a single order from EDP Renováveis for turbines capable of producing as much as 2,100 MW.

In its quarterly earnings report last week, Vestas said its 2010 forecast is for 8,000 MW to 9,000 MW of firm and unconditional turbine orders. Vestas expects most of the orders to come from Europe which its sees contributing nearly 50% of total orders, followed by the Americas with about 30%, and Asia/Pacific with approximately 20%.

In 2008 EDP had orders for 6,019 MW of wind turbines. In 2007, it had orders for 5,613 MW of turbines.

At the end of last year, Vestas put a hold on construction at three of four facilities in Colorado. But now, based on "market momentum," Vestas said it would begin full staffing in the US and that it plans to invest in a service and maintenance center in Colorado.

However, Vestas does not expect the uptick to be reflected in its earnings until the second half of 2010. The company is now expecting slightly lower EBIT margins of 10% to 11% in 2010 on revenues of €7 billion ($9.3 billion). Its 2009, Vestas' EBIT margin was 12.9% on revenues of €6.6 billion ($8.8 billion). Further out, Vestas is expecting to hit EBIT margins on 15% on revenues of €15 billion by 2015.

Vestas said that banks are beginning to venture back into project financing for wind projects, which could make the market more robust, but banks are more critical than they were before the credit squeeze and processing times and documentation requirements have gone up.

Vestas also cited the risk that low fossil fuel prices could dampen demand for wind turbines, as could lower energy consumption caused by economic trends coming out of the recession.

On the positive side, Vestas noted that the nature of the wind power industry is changing. It is moving away from supply only contracts because banks are now more often requiring one supplier to be responsible for an entire project. For Vestas that could smooth out the company's earnings.

Supply-only contracts for turbines lead to quarter-to-quarter earnings fluctuations, said Vestas, while supply contracts that have installation and/or maintenance provisions written into them could result in smoothing out some of those fluctuations. In addition, while supply-and-installation and turnkey contracts carry greater risks than supply-only contracts, Vestas noted that the more complex contracts also raise barriers to entry for other companies to enter the market.

In its contract with EDP, Vestas has agreed to supply and install 1,500 MW of turbines in 2011 and 2012 with the possibility of extending the contract by an additional 600 MW, exercisable in 2010 and 2011. The contract also includes a two-year service and maintenance agreement extendable to five or 10 years, with a "technical assistance agreement" for an additional period. *— Jeffrey Ryser and Peter Maloney*

RENEWABLE ENERGY

Canadian legislation sets out plan to allow BC Hydro to export renewable power to US

British Columbia, through crown corporation BC Hydro, is expected to acquire renewable power from independent power producers, make it reliable by firming it with its hydroelectric system, and export it to the US, under a new Clean Energy Act, or Bill 17, introduced last week.

Developing and then exporting the province's renewable power is one of 16 initiatives in Bill 17, many of which were proposed by a green energy task force established last year by Premier Gordon Campbell. The bill is expected to win the support of the Legislature and be approved in early June, Paul Kariya, executive director of the Independent Power Producers of British Columbia, said in a recent interview.

The bill excludes the British Columbia Utilities Commission from many BC Hydro actions, including future renewable requests for proposals, decisions surrounding Site C, a proposed 900-MW dam on the Peace River, and a feed-in tariff that the Clean Energy Act orders BC Hydro to establish. Campbell's government calls the action "modernizing" the regulatory body. The BCUC will still regulate rates and system reliability.

Additionally, Bill 17 requires that the British Columbia Transmission be incorporated into BC Hydro. The move will create a more efficient utility, according to the government.

Under the new Clean Energy Act, BC Hydro will be able to secure long-term export power agreements. Under current policy, BC Hydro does not contract for long-term export power sales. To secure more renewable power, BC Hydro will issue additional requests for proposals, or clean power calls, for renewable power, according to information provided by the British Columbia premier's office. During BC Hydro's last clean power call, it received responses for projects that could produce up to 14 million MWh of renewable power. BC Hydro has contracted to take about 3 million MWh of that power.

British Columbia imports some power from neighboring Alberta and the US to meet its power needs, but it has a goal of becoming self-sufficient in generation by 2016.

How that new renewable power will reach the US is still in question. BC Transmission continues to look for partners in a 3,000-MW transmission line it is studying to be built between British Columbia and California, said Mike Witherly, a spokesman for BC Transmission. *— Pam Radtke Russell*

Terra-Gen Power seeks FERC assurance of priority rights on new California grid lines

Terra-Gen Power LLC wants the Federal Energy Regulatory Commission to confirm its priority rights in three 230-kV transmission lines that would move their capacity to an interconnection with Southern California Edison. Citing prior decisions that made similar findings, the developers said they "are seeking regulatory certainty."

Comments on the filing are due May 24.

The Alta Wind Energy Center and Alta Solar Energy Center are both being developed by Terra-Gen, which is wholly owned subsidiary of ArcLight Capital Partners, an energy investment firm. The projects are being developed at sites near Mojave, California, in several stages, with some of the facilities coming on line in the first half of 2011 and all achieving commercial operation by 2016, explained the April 23 petition for declaratory order (EL10-62). It said more than $350 million already has been invested and minimum annual funding of $10 million is needed to complete the projects.

Three radial generator tie-lines will serve the projects, and the developers "do not intend to operate those facilities as part of a separate transmission business," the filing said. But consistent with commission policy, the petitioners committed to process any *bona fide*, third-party requests for service and to file an open-access tariff within 60 days of any such a request.

None of the lines are energized, but they are under construction and expect to be available for service late this year.

According to the filing, the Alta Wind I and Alta VI projects, each with net nameplate capacity of 150 MW, want confirmation of firm priority rights to essentially the full capacity of the 4.4-mile, 305-MW Transmission Line I. That line will feed into the 1.8-mile, 807-MW Transmission Line II, which additionally would serve the 150-MW Alta II and Alta III projects for which prior capacity rights also were sought. And the Alta IV (102-MW), Alta V (168-MW) and Alta VII (150-MW) projects requested priority rights in the 5.6-mile, 895-MW Transmission Line III.

Alta Windpower Development and TGP Development plan to construct additional projects with expected to exceed both the 207 MW of remaining capacity on the second line and the 475 MW on the third line.

AWD has an executed power purchase agreement for 1,550 MW pursuant to which Alta I, II, III, IV, V and VI have signed project-specific agreements to sell their output, the filing said. Supply contracts also are signed for 1,170 MW of required wind turbines, it added. The developers also have a large generator interconnection agreement with SoCal Ed and California Independent System Operator.

In March 2010 closed on a $394 million financing for the 150-MW Alta Wind I project, which is now under construction. The financing included a seven year construction and term loan, a bridge loan to for a cash grant from the Department of Energy, and ancillary credit facilities. Part of the proceeds from the financing will be used to repay pre-construction financing that closed in July 2009.

Credit Agricole and Natixis were co-bookrunners and co-structuring leads for the financing. The lender group also included Union Bank, Prudential Investment Management, Rabobank Nederland, and Banco Santander. *—Craig Cano and Peter Maloney*

ICE agrees to acquire Climate Exchange for $604 million in stock swap transaction

IntercontinentalExchange has agreed to buy UK-based Climate Exchange, which operates several emissions market exchanges, for $604 million, ICE said April 30.

Climate Exchange operates the European Climate Exchange, the Chicago Climate Exchange and the Chicago Climate Futures Exchange.

"The thought process behind the deal was actually quite simple," Richard Sandor, chairman and founder of CCX, said in an interview. "Here was an opportunity to take advantage of economies of scale and to create a single clearinghouse and a single trading platform."

Under the terms of the acquisition, Climate Exchange shareholders will receive £7.50 ($11.50)/share they own in Climate Exchange, valuing the entire existing issued and to be issued share capital of Climate Exchange at approximately £395 million ($604 million).

ICE, through its wholly owned subsidiary IntercontinentalExchange Holdings, acquired a 4.8% stake in Climate Exchange in June last year for £6.45/share.

Additional details would be provided upon the completion of the transaction, "at which time Climate Exchange will become a wholly owned subsidiary of ICE, operating under the Climate Exchange's respective brand names," ICE said.

Eron Bloomgarden, head of environmental markets at Equator, said Climate Exchange's European asset probably represented the "lion's share" of the valuation. "The European carbon market is already healthy, and is becoming a more mature market, with deeper liquidity and active trading and underlying certainty through the short- and medium-term. The North American market is more nascent, and some uncertainty exists whether there will even be a market."

Chris Allen, analyst at Ticonderoga Securities, said the acquisition is a reasonable long-term bet by ICE. "Given that the future of emissions trading is dependent on new laws to reduce emissions trading, which look a few years away, this is clearly a long-term bet for ICE," he said. "Although it is hard to define the potential size of the emissions market longer term, we believe that it clearly represents a long-term growth opportunity and is a market that should provide long-term synergies with ICE's core energy platform."

The deal, which Allen said represents a 57% premium on CLE's closing price on April 29, is expected to close in July.
—Stuart Elliott, Cheryl Buchta and Geoffrey Craig

Wave, tidal energy prospects remain distant but viable, says researcher

Technologies capable of harnessing ocean currents and waves to generate electricity are a long way from becoming cheap enough to attract commercial investment, the head of a research institute on ocean energy said.

Key technologies are "not yet cost competitive" and there is no timeline for when they will be, said Sue Skemp, executive director of the Center for Ocean Energy Technology at Florida Atlantic University said.

Speaking this week in Houston at the Offshore Technology Conference, which focuses mainly on technology for oil and natural gas exploration and production, she said the nascent renewable energy field still faces numerous regulatory, policy and environmental hurdles.

"We have to surmount the policy issues first" before the sector can develop, she said.

If it can overcome this, however, the global potential for such technology could eventually reach about 38,000 MW according to some estimates, she said. That compares to the US' installed generation capacity of about 1.1 million MW, according to the Energy Information Administration.

Ocean energy "is not *the* solution," she said. "It's an additional solution."

But one single offshore project — using "underwater wind turbines" to harness the power of tides and currents or employing the ocean as a solar collector — could require approval from multiple authorities, she said.

The offshore machines, transmission cable, connection to a land-based electrical grid and the staging area for construction could each be located in separate federal, state and even possibly international jurisdictions with a host of administering agencies.

"Many of these agencies have their own mission and decisions could be based on their singular missions instead of overall" objectives, she said.

And unlike oil and gas — where overlapping authorities have to some extent been decided — this is a new area with little cohesive policy to guide developers, she said.

While the Department of Energy as well as individual states have invested in some initial research centers, "there is still much to do," she said.

The field has also only started to scratch the surface of investigation into the possible environmental effects of such technologies.

In Florida, threatened sea turtles have been found in several areas identified as promising for ocean energy development. Aerial surveys of their habitats to use in estimating environmental risks of such project are set to begin soon, she said.

Wakes created by some machines, the alternation of the ocean floor, sediment movements and entanglements — either of animals or of the lines of trolling fishermen — are among possible environmental and usage concerns.

She said the sector shares more with the oil and gas industry than might be evident, including policy, environmental and even some technical considerations.

Ocean energy is faced with "all of the same issue you had to deal with in the oil and gas industry," Skemp said. The industry has to learn from things oil and gas "stubbed your toes on." *— Carla Bass*

REGULATION & LEGISLATION

EPA considers classifying coal ash as hazardous waste, seeks public comment

Environmental Protection Agency Administrator Lisa Jackson said May 4 that federal regulation of coal ash as a hazardous waste is possible, but under a "special waste" designation that she said would allow "beneficial" reuse of the substance to continue.

EPA issued for public comment two options on proposed rules for the disposal of coal combustion byproducts, which had been long awaited by environmental groups and feared by coal-burning utilities and industries that recycle coal ash. One EPA option would regulate the ash as a hazardous substance except when recycled for beneficial uses, and the other option would classify it as non-hazardous.

"This rule would be the first-ever nationwide standard for regulation of coal ash as a waste," Jackson noted during a conference call with reporters. EPA said the new rules will require the lining of coal ash storage facilities and "strong incentives" to store coal ash in dry form, seen as less dangerous than "wet storage" sites that can leak.

Coal ash is currently exempt from regulation, but EPA accelerated development of long-delayed standards for the material following a major spill in December 2008 at the Tennessee Valley Authority's Kingston plant that required a $1 billion cleanup. Utilities and industries that recycle coal combustion byproducts for use in a variety of commercial products argue that any "hazardous" designation would lead to exorbitant storage and disposal costs and crush beneficial reuse.

Environmental groups such as Earthjustice, while not pushing for elimination of beneficial use, have strongly pressed for tougher standards for disposal of coal ash, which contains contaminants like mercury, cadmium and arsenic.

EPA's proposed rule offers two options for public comment, one that coal ash be regulated as hazardous waste under subtitle C of the Resource Conservation and Recovery Act, and another option under subtitle D of RCRA that would designate it as a non-hazardous waste and require less strict enforcement.

On the argument that a subtitle C designation would limit beneficial uses of coal ash, Jackson said that "we have no evidence of that being the case." She said that in her view, the harmful constituent in coal ash "really becomes a problem only when you put a large amount of it on the ground, as in a landfill."

Edison Electric Institute spokesman Dan Riedinger said "our concern with the possibility of a hazardous waste designation is for liability reasons it would have such a chilling effect on beneficial use." EEI is the national association of investor-owned utilities.

A subtitle C, or hazardous designation, "would essentially kill beneficial use," he said.

Both utilities and some end users of coal ash have said they would have very strong concerns if the material were designated as hazardous, Riedinger said. The designation would leave utilities with a higher volume of coal ash to dispose of, pose more stringent requirement as to how the material is handled, and result in greater costs for utility customers, he said.

EPA said that under subtitle C, a comprehensive program of federally enforceable requirements for waste management and disposal would be created. The other option includes remedies under subtitle D, which gives EPA authority to set performance standards for waste management facilities but would not give EPA or states enforcement powers over those standards, and would limit enforcement to state or citizen lawsuits.

In either case, EPA said its new rules will ensure for the first time that protective controls, such as liners and groundwater monitoring, are in place at new landfills to protect groundwater and human health. Existing surface impoundments will also require liners, with strong incentives to close the impoundments and transition to safer landfills, which store coal ash in dry form. *— Jason Fordney*

CPUC seeks FERC backing on enforcement of feed-in tariffs for cogeneration facilities

To avoid a fight with utilities in courts over feed-in tariffs for cogeneration facilities, the California Public Utilities Commission has asked the Federal Energy Regulatory Commission to declare that the state's actions are not preempted by federal law.

Pacific Gas and Electric, Southern California Edison, San Diego Gas & Electric and Southern California Gas have threatened to sue the PUC over whether it has authority to require them to offer contracts to cogeneration facilities, also called combined heat and power systems, said the petition for a declaratory order.

The PUC asked FERC to find that the feed-in tariff decisions are not preempted by the Federal Power Act, the Public Utility Regulatory Policies Act or FERC regulations. The CPUC also requests that FERC grant waivers of its regulations, to the extent it deems necessary.

Under a state assembly bill on waste heat and reducing carbon emissions, the CPUC required utilities to offer contracts to combined heat and power systems of 20 MW or less. For cogeneration systems in congested areas, there is a 10% bonus to reflect the avoided costs of building additional distribution and transmission upgrades.

The PUC does not dispute FERC's exclusive authority over wholesale rates under the FPA, said the petition (Docket No. EL10-64). "The CPUC has only required that the retail electric utilities must offer contracts with certain prices to encourage CHP systems to be constructed, but does not require a CHP system to accept that offer."

In numerous orders, FERC has recognized that states have authority over the discretionary procurement decisions of the retail utilities, including the resource portfolios of those entities, said the petition.

Even if the petition raises issues that are a matter of first impression, FERC should find that the PUC's decisions "are not preempted due to the compelling nature and urgency of reducing [greenhouse gas] emissions, the legal authority that the states already have over the resource portfolios and procurement of retail utilities," and the different purposes of the environmental protection objectives of the bill and the economic objectives of FPA and PURPA. *—Esther Whieldon*

California agency approves replacement of once-through cooling at 23,000 MW of plants

California's State Water Resources Control Board on May 4 approved a plan that would replace once-through cooling systems at 19 coastal power plants in the state with a combined capacity of 23,000 MW.

The intention of the plan and policy is to cut the impact on marine life of once-through cooling, however, implementation of the plan is to be spread out over the next 14 years to maintain grid reliability.

To come into compliance with the policy, plants must reduce their intake flow rates by a minimum of 93%, which can be attained by the use of a closed-cycle, wet cooling system.

If a plant is not able to build such a system, the facility's impact on marine life must be reduced by minimization of intake flow rates or use of structural controls, the control board said.

The first plants that will come into compliance with the rules are the Humboldt Bay and Potrero facilities, which are due to be retired by December 31. The South Bay plant is to be retired December 31, 2011.

The state's two nuclear power plants, San Onofre and Diablo Canyon, will have until 2022 and 2024, respectively, to come into compliance with the rule.

The compliance dates for the remaining plants are tied to the California Public Utilities Commission's long-term power procurement plans for the state's three major investor-owned utilities.

Power plants in the San Francisco Bay area and San Diego region must comply with the regulations by 2015. Plants in the Los Angeles area must comply by 2017.

The board spent five years developing the policy to comply with the US Environmental Protection Agency's Clean Water Act, which requires that best available technology be employed to protect aquatic life. There is no national policy for existing plants. However, the North American Reliability Corp. has warned that the plan could force the closure of as much as 50,000 MW of capacity at a cost of around $100 billion (*GPR*, 29 April, 1). *— Lyn Corum*

Cal-ISO considers role of import limitations in contributing to San Diego area blackout

The California Independent System Operator said last week it is deciding whether to reduce or eliminate a power import limitation that played a key role in a brief San Diego blackout early this month.

Cal-ISO spokesman Gregg Fishman said the import limitation requires 25% of San Diego's power to be produced by local generators at all times.

"The import limitation was set years ago to help San Diego be able to more quickly recover in the event of a disturbance on the Western grid," Fishman said. Since then, mandatory reliability standards imposed by the North American Electric Reliability Corp. have lessened the need to keep 25% of San Diego's power coming from a local source, Fishman said.

Fishman confirmed April 29 that a control room operator has been fired and two others disciplined for not following Cal-ISO policy, leading to a brief blackout affecting about 300,000 homes and business in San Diego on April 1.

Fishman confirmed a report published April 28 by a San Diego-area newspaper, the *North County Times*, which quoted state Senator Christine Kehoe's account of a meeting she had the previous day with Cal-ISO officials to discuss the blackout. Fishman said the newspaper report correctly stated that a control room operator was dismissed for not following established procedures on how to react when areas of the Cal-ISO grid have insufficient power.

The blackout occurred shortly after Cal-ISO control room personnel improperly allowed a San Diego-area power plant to shut down. That decision set off an alarm in the control room to let personnel there know the grid was being operated outside the San Diego import limitation.

Because the import limitation is an operating requirement that is not subject to federal regulations that deal with stability limits, control room personnel should have waited until the additional generation they immediately ordered to come online did so and replaced the generator they had allowed to ramp down, instead of calling for firm load shedding. Generation was restored within two hours of the initial alarm.

"We have increased training for operators and we added alert systems in our control room that will signal to operators before we actually exceed import limitations," Fishman said. *— Daniel Guido*

California ISO goes back to the drawing board, scrapping previous renewable transmission plan

The California Independent System Operator has acquiesced to vociferous complaints from stakeholders representing independent generator owners and transmission developers and has discarded plans to create a new transmission policy for renewable energy.

In its place, the ISO proposes to revise its existing transmission plan to accommodate renewable power transmission proposals. To that effect, the ISO said it has discarded its "Renewable Energy Transmission Planning Process" and replaced it with the "Revised Transmission Planning Process."

The plan revision will not include the ISO's earlier proposal to allow a controversial right of first refusal to participating transmission owners. Although the ISO claimed to have taken that right out of is April 2 revision of the now defunct renewable transmission plan, stakeholders representing independent transmission and generation owners seemed to leave open the possibility of a right of first refusal. The now defunct plan would have allowed utilities to build all proposed transmission that would cross into their territories.

In proposing to revise its existing transmission plan, the ISO said in a five-page statement released on April 28 that it would allow sponsors of economic transmission projects, including those started in the past two years, to continue to develop their plans without worrying that a PTO will be allowed to come along and take over the project.

Economic transmission projects are projects that provide economic benefits, usually through access to less expensive resources, such as renewable power, or by relieving congestion.

The ISO said it wants to clarify its position by consolidating all of its transmission planning activities into a single comprehensive transmission planning process.

Stakeholders that complained that independent transmission companies were being improperly blocked from competing to build transmission projects within the ISO grid welcomed the change.

"In that five-page statement, they said more than they have said in the last nine months of stakeholder reviews of the now-abandoned renewable transmission plan," said Gary Ackerman, executive director of the Western Independent Transmission Group. Ackerman also holds the same title with the Western Power Trading Forum.

"The WITG found the ISO's amendment generally encouraging and a step in the right direction," Ackerman said. "We will continue to monitor and observe this process going forward and will be very interested in reading the proposed tariff change" that Cal-ISO staff plans to present to the system operator's board of governors' next meeting May 17 and 18.

Tariff change language will reference the ISO's transmission plan revisions, and if approved by the board, be sent to the Federal Energy Regulatory Commission for approval. *— Daniel Guido*

Court finds against FERC approval of station power charges in California ISO

The Federal Energy Regulatory Commission overstepped its authority by approving a tariff that preempts states from regulating retail sales of electricity to power plants, a federal appeals court found.

"FERC's order does not just sideswipe state jurisdiction; it attacks it frontally," said the ruling by the US Court of Appeals for the District of Columbia Circuit. Therefore, the court overturned FERC approval of the station power charges in California Independent System Operator markets and remanded the case for further proceedings.

At issue in the case (*Southern California Edison v. FERC*, 05-1327) is whether FERC went outside jurisdictional bounds when it approved changes to Cal-ISO's open-access transmission tariff to calculate generator station power on a one-month netting interval.

The tariff provisions allow generators in California to net their monthly station power needs against their deliveries of power to the transmission grid. In one of two orders on the tariff, FERC said load-serving entities may not impose retail and load-based charges on merchant generators that self-supply using monthly netting under to the ISO's station power protocol.

Station power is used by generators to meet their own lighting, heating and other electrical needs. Although some generators self-supply, there may be times when a plant is not operating and needs to pull power from the grid. Station power is considered retail load because it is not transmitted on an interstate basis, Southern California Edison argued before the court.

In response to a 2005 order, Cal-ISO revised its tariff to match FERC's station power policies that were established in a series of orders involving other utilities and regional transmission organizations. Merchant generators, including NRG Energy and Constellation Generation Group, had argued Cal-ISO's tariff was not in line with those policies.

The commission declared that if a generator's output exceeds demand for station power during a one-month interval, the generator would not be deemed to have made a retail purchase and could not be charged for retail energy or any other service subject to state jurisdiction.

While Cal-ISO calculates station power on a monthly basis, the California Public Utility Commission allows utilities to use 15-minute intervals to determine whether a generator has made a retail purchase of energy.

FERC failed to explain why the potential for undue discrimination in the way that utilities treat affiliates versus merchant generators "can be grounds to preempt the state's authority to set the netting period for station power — i.e., the pricing mechanism — in the retail market or to allow utilities to impose consumption charges," said the appeals court.

It also rejected FERC's assertion that to recognize the utilities' right to use a different netting period for station power as a retail sale under state law would cause a conflict with FERC's different netting period for transmission. "That is a familiar sort of preemption argument, but we do not see the conflict," the court said.

"After all, FERC has succeeded through its unbundling initiative in creating separate markets for wholesale sales, transmission and retail sales and distribution. Why should different pricing techniques cause a conflict?" *— Esther Whieldon*

Sempra Energy agrees to pay $410 mil to Calif. to settle litigation over 2000-2001 energy crisis

Sempra Energy on April 28 said it would pay California $410 million to settle litigation the state filed against the San Diego-based company for its actions during the 2000-2001 Western energy crisis.

Sempra said that as a result of the deal it would take a first-quarter charge that would reduce its after-tax earnings by about $96 million, or 38 cents/share.

In a separate statement announcing the settlement, California put the deal's value at $400 million.

Under the deal, utility customers in California would receive a $270 million reimbursement. The remaining $130 million would be paid to consumers for separate claims filed by the California Public Utilities Commission and the California Department of Water Resources, the state said.

"The settlements will put hundreds of millions of dollars back into the pockets of California energy consumers who suffered blackouts and great economic harm during the energy crisis," Attorney General Edmund Brown Jr. said in a statement.

California accused Sempra of "Enron-style gaming" of the energy markets, along with market manipulation and abuse.

Under the terms of the agreement neither Sempra nor RBS Sempra Commodities admitted any wrongdoing.

The settlement must be approved by the US Federal Energy Regulatory Commission before it can become final.

"After nearly a decade of litigation with California parties over issues related to the state's energy crisis, we are pleased to put these matters behind us," Sempra Chairman and CEO Donald Felsinger said. "We believe this is a fair and reasonable outcome for both our shareholders and the state of California."

Earlier this year, Sempra projected earning per share of $3.50 to $3.75, before the impact of the litigation reserve.

"Assuming continued break-even performance at RBS Sempra Commodities and the $96 million after-tax litigation reserve, Sempra Energy now expects overall earnings per share of $3.15 to $3.40 in 2010," the company said. The company is scheduled to announce its first quarter earnings on May 5. — *Eric Wieser*

Iowa governor signs legislation allowing MidAmerican to recover nuclear study costs

Iowa Governor Chet Culver on April 28 signed a bill that allows MidAmerican Energy to recover the costs of studying the feasibility of adding nuclear generation in the state.

The bill signed by Culver, H.F. 2399, lets MidAmerican Energy, which is under a rate freeze, recover $15 million over the next three years through a rate rider to study nuclear power. The legislation had broad support, passing the Senate on a 37-13 vote and the House of Representatives on a 91-7 vote.

MidAmerican plans to see what sites in Iowa can handle a nuclear plant and how much capacity could be supported, said Ann Thelen, a utility spokeswoman.

MidAmerican Energy's interest in building nuclear generation is driven by the general push towards building generating resources that produce little or no carbon dioxide, Thelen said. Currently, nuclear power is the only option for large baseload generation that does not produce carbon, she said. MidAmerican Energy's feasibility study will focus on its own needs, but if the company decides to move forward with a nuclear plant other utilities in the region could join the project, Thelen said.

MidAmerican Energy owns 9,172 MW of generation, including 4,802 MW of coal-fired plants and 1,284 MW wind. MidAmerican Energy and its parent company own and have sought to develop nuclear plants. MidAmerican Energy is a 25% owner of the 1,740-MW Quad Cities nuclear plant in Cordova, Illinois, with Exelon Generation owning the rest of the facility.

MidAmerican Energy's parent, MidAmerican Energy Holdings, recently explored building a nuclear power plant near Payette, Idaho, but in early 2008 cancelled those plans, saying the project would be too costly.

H.F. 2399 also requires the Iowa Utilities Board to provide advance ratemaking principals for converting existing coal-fired power plants to natural gas and other changes. Under the bill, utilities could also learn how the IUB will set the financial parameters for carbon capture and sequestration projects as well as adding biomass fuel to a coal plant before the project is built. — *Ethan Howland*

Bill introduced in House of Representatives aims to promote small nuclear power reactors

Two bills were introduced in the House of Representatives on April 28 that would promote the development of small nuclear power reactors.

Representative Jason Altmire, a Pennsylvania Democrat, introduced both measures with a bipartisan coalition of 19 co-sponsors to "advance the development of America's nuclear energy industry by facilitating the design and licensing of small nuclear reactors," Altmire's office said in a statement.

Altmire said "America's nuclear energy industry is on the brink of a new era of growth and development" and said his legislation would "help companies design and license smaller reactors that could be built more quickly and at a lower cost."

Designs for so-called small modular reactors, defined as nuclear generating units with a capacity of 300 MW or less, are being developed by several US and overseas firms. The designs that have been selected by US projects to build new power reactors are considerably larger, on the order of 1,000 MW. The Nuclear Regulatory Commission is actively reviewing 13 applications for combined construction permit-operating licenses to build 22 of these larger new nuclear reactors. Still, the nuclear industry has taken a great interest in the SMR designs.

One of the bills would require DOE "to carry out a research program to reduce manufacturing and construction costs relating to nuclear reactors." The other would require DOE to launch a public-private partnership to develop two standard designs for small modular reactors, at least one of which must have a capacity of not more than 50 MW, acquire a design certification for each from the NRC by January 2018 and acquire a combined construction permit-operating license for each by 2021.

At least 50% of the design development cost and at least 75% of the licensing costs must be borne "by a non-Federal source," the bill said.

One of the co-sponsors, Texas Representative Joe Barton from Texas, the senior Republican on the House Energy and Commerce Committee, said that "by facilitating the development of small nuclear reactors, this legislation could help bring nuclear technology to new regions of the country."

Alex Flint, senior vice president for the Nuclear Energy Institute, said in an statement that "the industry pledges to work" with Altmire and co-sponsors "to advance this legislation as a means of bringing innovative, small nuclear energy technologies to the commercial marketplace." — *Steven Dolley*

Pennsylvania reintroduces bill to promote renewable energy

Members of the Pennsylvania House of Representatives have repackaged and reintroduced legislation that would increase the amount of power that must come from renewable and alternative sources.

The measure, H.B. 2405, introduced last week, would require that 28% of the power supplied by electric power distributors in Pennsylvania come from renewable and alternative sources by

2024. The current requirement is 18% by 2020.

Under the new legislation, 15% of the state's power would come from what the legislation refers to as the cleanest sources, wind, low impact hydropower, geothermal, biologically derived methane gas, biomass energy, coal mine methane and solar. The solar requirement for photovoltaic and solar thermal would increase from 0.5% to 3% by 2020.

Another 13% would come from second-tier resources, which includes waste coal, distributed generation and demand side management. The bill sets a maximum of 3% for power produced by plants with carbon dioxide capture and storage, a technology in the second tier. The cap was meant to eliminate opposition to the use technology to capture carbon dioxide, Greg Vitali, a Democrat, and co-sponsor of the bill, said May 3 in an interview.

The bill replaces H.B. 80, which had been modified and amended many times since it was introduced in March 2009. "From a strategic perspective, a new bill with all the changes maximizes the chances it will be passed," Vitali said. The bill needs 102 votes to pass the House. "So we have had to figure out what it will take, including the best language, to get it passed," he said. — *Mary Powers*

Illinois fails to pass law to promote locally generated wind energy

Illinois lawmakers have failed to pass legislation to extend a preference for locally produced wind power under the state's renewable portfolio standard.

S.B. 3686 gives a preference to in-state wind developers for the state's electric utilities to meet provisions of the RPS. It requires utilities to source at least 25% of their power from renewables such as wind and solar by 2025.

The Illinois Power Agency, which procures power on behalf of Commonwealth Edison and Ameren Illinois, interprets the law as allowing an existing preference for Illinois wind to expire before new long-term power purchase agreements go into effect in 2012.

The bill, sponsored by State Senator Don Harmon, a Democrat, would extend the preference for another five years.

Until recently, the outlook appeared good to reach a compromise, perhaps by reducing the preference period to just one additional year. Chicago-based Exelon, ComEd's parent and the nation's largest nuclear generator, has opposed the extension, citing concerns over higher prices for consumers.

The bill's supporters, including the Illinois Wind Energy Association, contend Exelon is more concerned about an impact more wind generation could have on depressing wholesale power prices. — *Bob Matyi*

FERC proposal would lift price caps for power transmission capacity rights

Hoping to spur a secondary market for electric transmission capacity, the Federal Energy Regulatory Commission is proposing to permanently lift price caps on reassignments.

The April 29 notice of proposed rulemaking comes on the heels of a staff report concluding that removal of price caps during a 30-month study period did not present any anticompetitive concerns. If approved by FERC, the caps would be lifted on October 1.

Comments on the NOPR (Docket No. RM10-22) are due 60 days after its publication in the *Federal Register*.

Although FERC decided to lift the caps in Order 890, it backed off in a rehearing order that instead created the study period and directed staff to file a report by May 1. That report, which was presented to the commissioners at their open meeting last month, found "no indication that participants were able to or did take advantage of their capacity rights to manipulate prices."

Noting that both the number of transactions and volume of capacity experienced strong growth from May 2007 through the end of last year, FERC said there is "significant potential for further growth in the reassignment of capacity." The number of transactions rose from just over 200 in 2007 to almost 32,000 in 2009, while volumes went from 3 terawatt hours to 36 TWh over the same period, the NOPR said.

Given staff's finding that less than 1% of transactions involving affiliates were priced above the tariff rate that would have been the cap, FERC believes "there are no significant market power concerns to justify retaining the price caps for any transmission customers," the proposal said.

Nevertheless, it asked market participants to describe any alleged abuse they have experienced that would argue for maintaining the price cap on affiliates of the transmission provider.

In another primary finding, the report said the value of capacity reassignments "rarely exceeded the price differentials between relevant energy markets." The reassignments may be competing mostly with primary capacity, it said, and the overall low price levels for transactions seem to be "reflective of an uncongested transmission system with little scarcity of available capacity."

But the presence of reassignments for all durations — hourly, daily, monthly and yearly — indicated the secondary market is "a viable method for owners of primary capacity to sell excess capacity on a short- or long-term basis," the report said.

In the future, it continued, "unrestricted secondary market prices may enable capacity reassignments to increase as an alternative to transacting in the energy market and provide price signal to indicate scarcity and appropriate areas for new investment."

With an eye toward that future, the NOPR asked if there are any other reforms FERC could undertake to create a more "efficient and vibrant" secondary market. Are there non-price limitations or regional factors that limit the utility of reassignment? If so, how should they be addressed?

For example, are there reforms "to the redirect process that would enable all firm customers to use their firm capacity more flexibly and thereby facilitate capacity reassignment by making [delivery] point changes by the buyer of reassigned capacity more efficient?"

For the gas industry, FERC established a system of secondary firm point priorities to provide greater flexibility in the use of firm capacity. Secondary firm priority provides a shipper with scheduling rights to a new point that are superior to non-firm service but inferior to primary firm service for shippers using points specified in the contract.

In addition to asking whether additional safeguards are needed for reassignments by affiliates of the transmission provider, the NOPR queried: How should reassignments by a transmission provider's retail service function that is not a separate affiliate be treated?

FERC said it will continue to monitor the secondary market for evidence of abuse of market power, relying on transactional information that must be posted on transmission providers' open-access same-time information systems and the service agreements that must be executed before an assignee's service begins. — *Craig Cano*

Connecticut lawmakers draw protest as they consider power market changes

Connecticut legislative leaders have drawn a storm of protest by proposing significant 11th-hour changes to power regulation and markets, including study of possible withdrawal from ISO New England.

Industry insiders were scrambling this week to understand last-minute amendments to energy bill S.B., 493, sleeper legislation that took on new life when House of Representatives and Senate leaders put it on a fast track for action before the session ends May 5.

The bill is unusual in that it is backed by two legislative powerhouses who have traditionally been at odds over energy policy, Senator John Fonfara, Democrat from Hartford, and Representative Vickie Nardello, Democrat from Prospect, who serve as co-chairmen of the Energy and Technology Committee.

Connecticut is the second state to broach the idea of leaving the ISO as a cost-saving measure. Maine spent several years studying the pro and cons, but eventually decided to instead work for ISO reform, in particular for more consumer representation.

The legislation also would make a host of other policy changes, including creating a new superagency known as the Connecticut Energy and Technology Authority, which will oversee the Department of Public Utility Control. The authority would have a range of powers, among them the ability to take buy power and solicit new generation in certain circumstances.

Kevin Delgobbo, DPUC chairman, said he has "significant concerns" about the bill, in a letter sent to legislative leaders May 3 and co-signed by Robert Genuario, secretary of the Office of Policy Management. The letter said the bill would increase ratepayer cost and risk, threaten competition, and jeopardize the DPUC's ability to legally regulate the industry.

"The administration can accept a number of these provisions as well intended; however, we believe that the provisions of this proposed legislation pass the tipping point, which places Connecticut's ratepayers at risk for increased costs," the letter said.

For example, the bill adds $72 million in solar incentives plus $9 million in administrative costs. "These additional costs will be borne by both residential and commercial ratepayers," the letter said.

At the same time, the bill calls for a 15% reduction in electricity rates by July 1, 2012, a provision that could inadvertently undermine the state's efforts to reduce power costs through energy efficiency, said Jessie Stratton, director of government relations for Environment Northeast.

This would occur, she said, because part of the spending for energy efficiency comes through a systems-benefit charge on ratepayer bills, which could be reduced to reach the 15% goal. As a result, energy users could see a cut in their rates, but lose the decrease in their energy costs possible through efficiency.

"Our real concern is charging ahead with an incomplete analysis and understanding of the potential impact," she said. "We agree that some restructuring makes sense, but it needs to be thoroughly vetted."

The bill calls for the DPUC to begin a review in August of the state's involvement with the ISO, including the cost and benefits to the state, and possible benefits of joining another ISO or operating outside an ISO. The report is due to state lawmakers by January 1, 2011. — *Lisa Wood*