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NERC's 2007 reliability assessment sees shortfalls, but discounts merchant projects

The debate about how much generating capacity will be needed to meet minimum reserve margins in the next 10 years will continue as the North American Electric Reliability Corp. painted a bleak assessment and called for significant new additions to keep up with demand growth in its annual long-term forecast.

NERC estimates that peak demand in the US will increase by almost 18%, or 135,000 MW, in the next 10 years. In contrast, committed resources used to meet demand, including demand response programs, are projected to increase by about 8.5%, or 77,000 MW. Counting what NERC defines as uncommitted resources, total resources would increase by 12.7%, or 123,000 MW.

Last year, NERC estimated that demand for electricity would increase 19% in the US over the next 10 years, but confirmed power capacity would increase only 6%. Those estimates were based on demand rising to 141,000 MW, with committed resource additions growing by only 57,000 MW (*GPR*, 19 Oct, '06, 1).

While it is difficult to pinpoint the reason, or reasons, for a nation-wide decline, the decline itself is not surprising, said

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Global interest in climate change spurs M&A of wind assets; attracts EU firms to the US

Wind farms are hot, especially for European companies looking for a foothold in the US wind power market.

In the past year or so there have been at least eight deals — seven closed and one announced — involving the acquisition of US wind assets by European energy companies. Those eight transactions represent a total value of about $4.5 billion — financial details of many of the deals were not released, so an accurate total is hard to come by — but the lion's share of the value, about $4.3 billion, is concentrated in the two most recent deals: Energias de Portugal's $2.9 billion purchase of Horizon Wind Energy from Goldman Sachs in July and E.ON's announcement last week that it plans to buy the North American wind assets of Airtricity for $1.4 billion and the assumption of $553 million in debt (*GPR*, 11 Oct, 4).

Those eight deals also represent an acceleration of wind power mergers and acquisitions and a rising trend in the valuation of wind power assets.

The first movers from Europe were Electricite de France and Spanish wind turbine manufacturer Gamesa Energia. In 2002 EdF acquired California wind farm developer enXco, and Gamesa acquired a 75% stake in Navitas Energy Inc. of

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Black Hills mulls sale of unregulated plants totaling 1,000 MW in western United States

Black Hills' decision to conduct a strategic review that likely will include selling its interests in 11 non-regulated power plants with about 1,000 MW total was driven largely by strong prices for efficient, newer plants, company officials contend.

"Given prevailing favorable market conditions in the independent power sector of the energy industry, it is prudent to assess our strategic alternatives. We have great assets in geographic locations with strong population and customer load growth," said David Emery, chairman, president and CEO in announcing the move late last week.

The plants are in Colorado, Wyoming, California, Nevada and Idaho. Some 99% of the power is sold under contracts and the fuel mix is 91% gas and 9% coal. The company also is building a 149-MW gas-fired plant in New Mexico.

For the first half of 2007, availability was 98.3%. Black Hills' non-regulated generation had revenue of $79.5 million for the six months and income from continuing operations was $10.4 million. For full year 2006, the non-regulated generation revenue was $155 million and income was $19.9 million.

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"We don't know yet if we will sell all or just some of our plants, or, if a sale would be to one or more bidders," said Dale Jahr, director of investor relations in an interview. "We will do a review and determine a process for soliciting bids. There is no time frame for this process."

Proceeds "could have many potential uses," said Jahr. There is the possibility that cash generated from any deal could go toward its $940 million acquisition of utility assets from Aquila, paying down debt or be devoted to other treasury needs, he noted.

Black Hills has retained Credit Suisse Securities (USA) as financial advisor on its strategic options.

Prices are at a premium today for newer, efficient gas- and coal-fired plants because banks, other financial entities and equity funds are willing to pay top dollar for these plants as investments, say industry sources. These entities formerly may have been the ones financing plants and now are acquiring assets and getting into the independent power business.

Behind the price rise is concern about carbon emissions, sources contend. "If a plant is efficient it will be worth more money in the future because older, less efficient plants will be retired. The cost would be prohibitive to upgrade them to meet new government carbon emission standards," said one analyst.

"People with money are anticipating that when the government releases new carbon rules, older plants will be shuttered so new plants will be worth more money," the analyst noted. Conventional gas-fired plants will be at a premium because they emit 70% of the carbon that a coal-fired plant emits, he said.

The carbon issue will make efficient, cleaner coal-fired plants more valuable because the country still depends on coal which produces about half of the power consumed today, sources believe.

Black Hills' unregulated business owns two coal-fired plants located in Wyoming, the 90-MW Wygen 1 and the 40-MW Gillette CT.

The company's gas-fired plants involved in the review are the 98-MW Harbor and 12-MW Ontario plants in California; the 80-MW Valmont, 130-MW Arapahoe and 240-MW Fountain Valley plants in Colorado and the 51-MW Las Vegas I and the 225-MW Las Vegas II plants in Nevada. In Rupert and Glenns Ferry, Idaho, it owns a 50% interest in two gas-fired qualified facilities with an ownership share of 22 MW.

Black Hills said it sells capacity and energy under a combination of mid-to long-term contracts, which helps mitigate impacts of a potential downturn in future power prices. It sells additional power into the wholesale power markets when available and economic. The company mitigates financial exposure by selling a majority of unregulated capacity and energy under "tolling" agreements under which the power purchaser is responsible for supplying fuel for the facility, assuming fuel price risk. The contracted purchasers of capacity and energy are load-serving utilities.

NERC's 2007 reliability asessment sees shortfalls, but discounts merchants ... from page 1

David Nevius, senior vice president of NERC. Likely reasons, he said in an interview, are lower estimates of economic growth and the greater number of demand-reduction programs that are being planned.

The near-term estimates are not as dire as NERC's estimates might suggest, said Steve Piper, power forecast economist with

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Platts Energy Advantage, an affiliate of *Global Power Report*. Energy Advantage estimates that about 12 GW a year will be added up until 2010.

"The really alarming thing," said Piper, "is the pull-back from coal plants." In the 2010-2015 time frame, there could be a gap left by the pull-back from coal that is not being filled.

Until recently there were 35 GW to 40 GW of coal-fired projects being planned, said Piper. But once TXU became the "poster boy" for environmental opposition — and then agreed to cancel eight proposed 858-MW of coal plants as a condition of its buyout by a private equity consortium led by Kohlberg Kravis Roberts and TPG Capital — developers began to cancel plans for coal-fired plants. Piper estimates that the coal project pipeline has been cut by half, to about 20 GW. But many utilities and municipal utilities are still pushing coal, so there could be some offset. "We'll have to see," he said.

Overall, though, "NERC is more inclined to say the sky is falling," said Piper. It is essentially an engineering entity and is not as concerned about market efficiency, he said.

That is certainly reflected in NERC's treatment of uncommitted capacity. Like last year's forecast, there are different figures from NERC on how big the gap between demand growth and capacity additions will become, based on the uncertainty associated with how generation resources are counted. Plants that are built but do not have a purchase contract, or that are in the planning stages but not counted by utilities as a designated resource, are classified as uncommitted resources by NERC, and NERC has vowed to improve its definition of such resources.

"We've flagged it as an action item" because "we want to be more precise about how much capacity is out there" that is not counted for reliability purposes, said NERC's Nevius.

Estimated 2016/2017 Winter Resources and Demands (MW) and Margins (%)

	Net internal demand (MW)	Net capacity resources (MW)	Uncommitted resources (MW)	w/o uncommitted available capacity margin (%)	with uncommitted potential capacity margin (%)
United States					
ERCOT	56,053	76,832	27,939	27.0	46.5
FRCC	56,274	72,102	1,227	22.0	23.3
MRO	41,377	49,179	0	15.9	15.9
NPCC	54,234	75,872	3,554	28.5	31.7
New England	25,620	34,203	19	25.1	25.1
New York	28,614	41,669	3,535	31.3	36.7
RFC	165,500	222,419	5,300	25.6	27.3
SERC	201,706	269,099	47,685	25.0	36.3
Central	45,749	54,225	4,487	15.6	22.1
Delta	27,106	37,871	14,198	28.4	47.9
Gateway	15,966	22,282	10,423	28.3	51.2
Southeastern	49,720	72,368	7,753	31.3	37.9
VACAR	63,165	82,353	10,824	23.3	32.2
SPP	36,104	57,480	10,489	37.2	46.9
WECC	123,817	169,164	5,638	26.8	29.2
AZ-NM-SNV	23,641	38,857	0	39.2	39.2
CA-MX US	43,544	58,624	4,617	25.7	31.3
NWPP	45,658	57,764	828	21.0	22.1
RMPA	11,815	11,552	194	-2.3	-0.6
Total-United States	**735,065**	**992,147**	**101,832**	**25.9**	**32.8**
Canada					
MRO	7,632	10,026	100	23.9	24.6
NPCC	66,132	83,718	1,633	21.0	21.7
Maritimes	6,297	6,945	758	9.3	18.3
Ontario	22,602	34,410	0	34.3	34.3
Quebec	37,233	42,363	875	12.1	12.1
WECC	25,188	27,852	1,125	9.6	13.1
Total-Canada	**98,952**	**121,596**	**2,858**	**18.6**	**19.9**
Mexico					
WECC CA-MX Mex	2,529	2,811	0	10.0	10.0
Total-NERC	836,546	1,116,554	104,690	25.1	31.5

Source: North American Electric Reliability Corp.

Nevius said he is confident that NERC will have a better handle on how to count such capacity by the time NERC issues its next long-term forecast in the fall of 2008.

Much of what NERC defines as uncommitted resources are merchant power plants. NERC's definition of uncommitted capacity resources includes resources that fall into one or more of the following categories: they lack a power sales contract or a regulatory obligation to deliver power during peak demand; they do not have firm transmission rights or a transmission study; they are designated energy-only resources, or they are transmission-constrained resources.

"NERC will improve its definition of uncommitted resources and various gradations of certainty for future resources to improve its assessment of long-term capacity margins," the organization said in the report released on October 16.

The distinction between what NERC calls committed and uncommitted resources, which can center on how utilities designate merchant plants or other resources in meeting their needs, results in a less dire need for new facilities in some parts of the country. Because there are more than 50,000 MW of uncommitted resources, much of them in the Southeast and Electric Reliability Council of Texas, "we want to differentiate between what can be considered available and what is not," Nevius said.

NERC's assessment says electricity demand will grow faster than planned generation and transmission resource additions in the US and Canada in the coming decade. The forecast says electricity usage is projected to grow more than twice as fast as committed resources over the next 10 years and that unless additional resources are brought into service, reserve margins could fall below their targets within two to three years. In parts of western Canada, demand is projected to outpace resource growth within about two years, NERC said.

Peak demand in the US is forecast to increase by almost 18% in the next 10 years. In contrast, committed resources used to meet demand, including demand response programs, are projected to increase by about 8.5%. Counting uncommitted resources, total resources would increase by 12.7%.

In this year's report, NERC estimates that peak demand in Canada will increase 6.4%, or 6,000 MW, in the next 10 years, while committed resources are projected to increase by more than 10%, or 11,000 MW. When uncommitted resources are included, capacity additions in Canada would be almost 14,000 MW in the same time frame. Demand growth in Canada varies greatly from province to province, and while Ontario's conservation and demand reduction efforts are expected to blunt some of the growth there, British Columbia and Alberta expect to see large gains, the report said.

While the gap between demand growth and capacity additions shows some improvement over projections from NERC's 2006 long-term forecast, "certain areas will still need additional supply-side or demand-side resources in the near-term to ensure adequate margins," NERC said. California, New England, Texas, Rocky Mountain states and the Southwest and Midwest could fall below their target capacity margins within two or three years if new supply-side and demand-side resources are not brought into service, NERC said.

As reserve margins fall and the transmission grid is operated with less margin for error, reliability can be hindered, NERC said. Transmission investment has been lagging for years and more facilities will be needed "as each peak season puts more and more strain on the transmission system, especially in constrained areas" such as the Northeast, California, the southwest and parts of Ontario.

While several transmission projects were completed in the past year and numerous more are planned, projected additions still lag demand growth and new generation additions in most areas, NERC said. Transmission miles are forecast to grow by 8.8%, or 14,500 circuit miles, in the US and by 4.8%, or 2,250 circuit miles, in Canada over the next 10 years.

Emergency reliability situations are becoming more frequent, and while some improvements have been made "we are requiring our aging grid to bear more and more strain, and are operating the system at or near its limits more often than ever before," NERC President and CEO Rick Sergel said in a statement.

The long-term reliability assessment highlighted several obstacles that need to be addressed by the power industry in the coming years, including an aging work force and the integration of renewable resources. About 40% of senior electrical engineers and shift supervisors will be eligible for retirement in 2009, and NERC will hold a workshop later this year to create an industry action plan to address the looming retirement of employees. Aggressive recruiting and training of engineers and industry workers, in conjunction with universities, can help, NERC added.

New generation planned from large wind and solar projects can help meet demand and aid in diversifying the North American generation fuel mix, but integrating them with the transmission grid has its challenges. Because such large renewable resource additions are often in remote locations, new transmission lines are needed to bring their power to areas of high demand, NERC said. "We must pin down how much power these renewables can consistently produce during peak demand times so that they can be factored into reliability planning," Sergel said.

New nuclear plants that are being proposed or considered in different parts of the country, because of their large size, also will require expansion and strengthening of the transmission grid to allow a smooth integration, NERC added.

In Florida, Texas, the Northeast and Southern California, natural gas-fired generation has become increasingly popular and that reliance on natural gas for generation purposes could pose electricity reliability concerns, NERC added. Competition for gas supplies among the different regions, along with declining imports from Canada, could affect grid reliability. Although liquefied natural gas imports can boost supplies, they expose the bulk power grid to the whims of global economic and political risks, NERC said. While a number of steps have been taken to try and mitigate reliability impacts because of high reliance on natural gas supplies, "more action is needed," NERC said.

Transmission additions are picking up, but siting, financing and building new lines continues to be difficult for the industry, NERC said, mentioning the preponderance of "not in my back yard" concerns among landowners and states where new lines are planned. In many instances, transmission additions cut through states that may not stand to benefit directly from new lines, and "NIMBY is becoming NIMS: Not in My State," Sergel said. States that oppose new transmission additions need to realize the interconnectedness of the power grid, as was demonstrated in the 2003 blackout when power lines went down in Ohio and 50 million people went without electricity, Sergel said during a conference call.

Forward capacity markets, which are developing or in place in some regions of the country, are showing promise by providing price signals to indicate where new resources are needed, Sergel said. "We're pleased to see the development of forward capacity markets," he said. Although they are not providing tangible results in the form of capacity additions yet, preliminary results suggest that capacity will be added if regulators encourage investments in new resources, Sergel said.

In this year's assessment, NERC included a brief discussion of two different scenarios – one dealing with legislation to meet carbon reduction goals and one dealing with elevated natural gas demand. The carbon-constrained scenario includes large additions of wind, demand response and nuclear resources, which would require changes in transmission system design, operating margins and ancillary service requirements. To account for increased penetration of demand response programs, the predictability of those resources needs to be better understood, NERC said.

Among the conclusions from the elevated natural gas demand scenario, NERC said, federal and state authorities should support industry efforts to diversify the generation fuel mix, and power plant developers should sign long-term fuel and transportation contracts.

The report is available at NERC's web site, www.nerc.com.

Interest in climate change spurs wind M&A in US by EU companies ... from page 1

Minneapolis.

By 2005 activity had stepped up, though most of the announcements involved larger, more established US companies, such as AES Corp. and PPM Energy, buying up smaller development companies, such as SeaWest and Atlantic Renewable Energy. But by 2006 European companies were outpacing US firms in wind farm acquisitions. Iberdrola paid $30 million for Community Energy, which had 2,000 MW of wind farms under development, and announced plans to buy Midwest Renewable Energy Corp.

In September Enel SpA of Italy, through its Enel North America subsidiary, took a large stake in TradeWind Energy LLC and formed a strategic partnership to build out the Lenexa, Kansas, firm's 1,000 MW of wind power projects.

Later that year, BP of Britain bought Greenlight Energy, which had a development pipeline of about 6,500 MW of wind projects in the US, and then bought Orion Energy, which had 1,300 MW of US wind projects in development.

In June 2007 Spanish construction group Acciona acquired the rights to 1,300 MW of wind projects in Illinois, Iowa and Wisconsin developed by EcoEnergy, a unit of The Morse Group. In March EDP announced its plans to acquire Horizon Wind from Goldman Sachs, and in April Iberdrola bought CPV Wind Ventures' 3,500-MW development pipeline for $74 million. That same month, Iberdrola took ownership of PPM Energy's 2,000-MW wind portfolio through its acquisition of ScottishPower.

Iberdrola's acquisitions pushed it to the top of global wind asset ownership, moving it ahead of rival FPL Energy in terms of the installed capacity of its portfolio. It also set the stage for even bigger deals to come.

Analysts see EdP's acquisition as either a plateauing of wind M&A activity, or the beginning of a second phase. The plateau camp looks at the price EDP paid; many in the industry were surprised at that price, in part because Goldman Sachs acquired the Horizon assets from Zilkha Renewable Energy barely two years earlier. Goldman booked a $900 million gain on the sale in its third-quarter 2007 earnings.

Those who think a second wave is under way, point to E.ON's announcement that it plans to acquire Airtricity's North American assets. The first wave reached a peak with BP's two acquisitions, says Joshua Magee, a senior analyst with Emerging Energy Research of Cambridge, Massachusetts. He argues that there were still several pure play development companies in 2005, companies that had large, geographically diverse project pipelines, but relatively small balance sheets, companies such as Zilkha, SeaWest, enXco and Community Energy, which were all bought up by either US or European buyers. The last companies with good track records and geographically diverse portfolios, Greenlight and Orion, were then bought by BP, says Magee. He argues that the EDP-Horizon acquisition was the first deal in the second wave of wind M&A.

In the second phase, independents are acquiring one another, and foreign companies that missed the first round are paying higher prices to enter the market, says Magee.

Not all wind projects are created equal

The difference in valuations can be seen by comparing the prices paid by BP and EDP. The valuations range from $15/kW for BP's purchase to $1,933/kW for EDP's.

Analysts acknowledge, however, that it is difficult to come up with valuations for these deals. The crucial factor is assessing the value of development projects. All of the recent transactions include a development "pipeline." In fact, some of the transactions are for nothing but projects in development, Enel's TradeWind deal, for instance.

Valued on the basis of operating wind projects alone, some of the values would be absurdly high. That is especially true of the more recent deals. Airtricity, for instance, has only 210 MW of operating wind assets in North America. At $1.4 billion that would value E.ON's acquisition at about $6,660/kW. But if the 880 MW of Airtricity projects that E.ON expects to enter service by year end are included, the valuation drops to $1,284. If the debt assumption is included, the valuations range from $9,300/kW to $2,219/kW.

In the same vein, using the 722 MW of operating wind farms that EDP bought for $2.15 billion in equity, the company paid $2,978/kW. But EDP expects to have about 1,500 MW online by year end, and on that basis EDP paid $1,382/kW. If the debt assumption is included, the valuations range from $4,016/kW to $1,933/kW.

Analysts agree that the key determinant in assessing these deals is evaluating the quality of the pipeline projects. To do so, they take several factors into account to gauge the probability of a project's success. Does the project have land on which to build? Does it have environmental permits for the site? Will the wind turbines be available when they are needed?

One analyst estimates that, based on operating wind farms alone, EDP paid $2,200/kW for Horizon's assets. If plants under construction that are expected to come online this year are included in the calculation, the number falls to $1,940. And, if Horizon's entire pipeline is included, the valuation falls to $1,853/kW. She puts the high-end valuation of the E.ON-Airtricity deal at $2,200/kW and the mid-range at $1,975/kW.

A banker at Credit Suisse who worked on the E.ON-Airtricity deal, said that a quick calculation of Horizon's back-end (read, distant) projects yields a value of $90/kW. For Horizon projects in operation or in later stages of development — 18 months to two years from entering service — Credit Suisse assigned a value of $2,000/kW. Applying the same metrics to Airtricity, Credit Suisse came up with an implied value of $2,100/kW.

Are valuations rising? "Yes," said the banker.

The increases are a function of rising construction costs and where a project is located, he said. Airtricity, for example is primarily in Texas, so it is a play on the Electric Reliability Council of Texas market.

Location, specifically the quality of the wind resource and the proximity of a site to load centers, can result in wide differences in the valuation of projects within a portfolio. In other words, not all wind projects are created equal. As one analyst noted, Horizon's assets were able to command a premium in part because they have particularly high capacity factors of about 40% compared with about 30% for most wind projects.

In fact, there is a shift under way, said Tamir Druz, an analyst with Tower Perrin. Acquirers are showing greater interest in wind portfolios in the eastern US, in part because many western portfolios have already been bought up, but also because many northeastern states have strong renewable portfolio standards and sites are closer to load centers. It is also harder to site a wind project in the Northeast, and that makes permitted projects more valuable and puts upward pressure on the price a seller will seek.

For many European companies, it could be worth paying a premium for a portfolio of existing and nearly done projects, said Druz. And if those projects are in the Northeast, they could command an even higher premium.

In addition, the cost of building a wind farm has risen steadily, said Druz, further tipping the scale in favor of buying rather than building. Five years ago it cost about $1 million/MW to build a wind farm, he said. Three years ago that price was $1.2 million. Now it is around $1.7 million/MW. That means that the gap between the build price, $1,700/kW, and the buy price, $1,900/kW to $2,100/kW, is narrowing. And when political and

Major US wind company acquisitions and equity investments, 2005 to the present

Date Announced	Investor	Target company	MW developed by target company at time of acquisition	MW pipeline of target company at time of acquisition (est.)	Pipeline geographic focus	Purchase price
Jan. 2005	PPM Energy	Atlantic Renewable Energy	162	500	NY, PA, WV, NJ	n/a
Jan. 2005	AES	SeaWest	784	1,800	Western US	n/a
Mar. 2005	Goldman Sachs	Zilkha Renewable Energy	232	4,000	National	n/a
Dec. 2005	Airtricity	RGI	(none)	1,000	TX, NM, CO	n/a
Jan. 2006	Babcock & Brown	G3 Energy	n/a	150 (excluding JVs)	TX, NM, NV, PA, Canada	n/a
May 2006	Iberdrola	Community Energy	32	2,000	Northeast, Mid-Atlantic	US$30 million
Jul. 2006	NRG Energy	Padoma Wind Power	523	1,000 (excluding JVs)	TX, NM, CA	n/a
Aug. 2006	BP Alternative Energy	Greenlight Energy	150	6,500	CO, IL, KS, ND, other	US$98 million
Aug. 2006	Babcock & Brown	Superior Renewable	50	1,100 (includes Gulf Wind)	CA, NM, TX, SD	n/a
Sept. 2006	Enel	TradeWind Energy	(none)	1,000	KS, MO, IL	<US$10 million (est.)
Oct. 2006	Iberdrola	MREC	80	1,700	IA, WI	US$38 million
Dec. 2006	BP Alternative Energy	Orion Energy	491	6,000	National	n/a
Mar. 2007	EDP	Horizon Wind Energy	1,044	9,000+	Southwest, West, Mid-Atlantic	US$2.9 billion
Apr. 2007	Iberdrola	CPV Wind	(none)	3,500	Southwest, Midwest, Mid-Atlantic	US$73.8 million (est.)
May 2007	Duke Energy	Tierra Energy	(none)	1,200	Southwest	n/a
Jul. 2007	Acciona	EcoEnergy	(none)	1,300	IA, IL, WI	n/a
Aug. 2007	ArcLight Capital	Caithness Energy	338	(none)	n/a	n/a
Oct. 2007	E.ON	Airtricity North America	278.5	7,000	Southwest, Mid-Atlantic, Midwest	US$1.37 billion

Source: Companies, Emerging Energy Research regulatory factors are taken into account, the scales tip even further in favor of buying a project rather than building one.

For a foreign buyer, buying a project, or a portfolio of projects, removes a lot of the risk, said Druz. Many of the big European energy companies have a lot of experience operating wind farms, but little experience navigating the US regulatory process. Buying wind farms also avoids about three years of lost revenues during development and construction. In sum, it allows a company that is confident of its O&M skills to play to its strengths while minimizing its potential weakness, developing a project in a foreign regulatory and political environment.

If you can make it here

So, in the face of rising prices, is the appetite for US renewable assets, particularly wind assets, going to slow any time soon? Not likely, say analysts.

"Even though everyone screams that the prices are high, prices here are a bargain compared with Europe," said Edwin Feo, co-chair of Milbank Tweed Hadley & McCloy's global project finance group. European companies account for about 80% of the M&A activity for US wind assets, he says, and that is not likely to slow significantly.

The biggest driver for these deals is not costs, but the potential of the US wind power market. Ernst & Young, in its Renewable Energy Country Attractiveness Index, rates the United States as the top market for renewable energy.

E&Y's rating is based on the strength of the regulatory and legal infrastructure in the US and the varied incentives, but also on the potential size of the market.

The total capacity of US wind farms hit 12,600 MW in June 2007, according to the American Wind Energy Association, representing about 1.5% of total US power capacity. In Europe, wind power accounts for 10% to 15% of some countries' total installed capacity. Germany, for instance, has about 20,620 MW of wind farms and a total installed capacity of about 132,000 MW.

Market potential was a driver for EDP. "The United States is the fastest growing market in the world for wind power," said Antonio Mexia, EDP's CEO, in an interview. "In the US you can build a 200-MW or 300-MW wind farm. In Europe you can't do that. If we want to be a leader, we have to be here."

Mexia says the US has the potential for the installation of 16,500 MW of wind capacity by 2010, and aims for EdP to gain a 12% market share of the projected 80,000-MW US wind market by 2020. By 2010, Mexia says EDP will have 7,600 MW of capacity globally, with 4,200 MW in Europe and 3,400 MW in the US.

In addition to wide open, windy spaces the United States has incentives for developers of renewable energy projects at both the federal and state level. That is a highly effective combination, says Ernst & Young.

At the federal level, there is the production credit of about $2 cents/kWh. At the state level 25 states have now passed some form of renewable portfolio standard.

Neither alone would be a sufficient incentive, say analysts, because most renewable portfolio standards call for negotiated-price contracts. On that basis alone, it could be difficult to provide the advance certainty that bankers like to have before agreeing to finance an acquisition or a project.

The negotiated nature of an RPS contracts can result in "leakage of value away from the developer," as one analyst said. But the PTC, even if the acquirer does not need it, provides stability.

"The PTC anchored the Horizon deal," said Feo, because the value of the tax credits was known and fungible before the close. That enabled Citigroup to engineer a deal structure under which EDP monetized the tax credits the day before the acquisition closed. That gave EDP $700 million to pay down debt at the closing and increased the available cash flow that EDP could apply to the transaction. It was also likely one of the reasons EDP was able to edge out competing bids, many of which came from deep-pocketed financial players.

Mexia, EDP's CEO, says that is how the company plans to handle tax credits that Horizon throws off in the future. Just last month EDP said it would likely finance 650 MW of equity tax credits before year end (*GPR*, 4 Oct, 5). But that is not the only option.

Iberdrola also has PTCs, from its ownership of PPM Energy, but rather than monetizing the credits, Iberdrola is buying Energy East so it will have income to soak up the value of the tax credits. Energy East distributes electricity and gas from Maine to New York and has $5.2 billion in revenues.

A spokesman for E.ON said that the company has not made an overarching decision on how to handle the tax credits it

Valuations of recent wind power acquisitions

Buyer	Asset	Status	assets (in MW) in operation	in development late	early	purchase price ($ millions)	valuations ($/kW)* based on projects in: operation	operation + late devel.	early devel.
BP	Greenlight Energy	closed			6,500	98	na	na	$15
Iberdrola	CPV Wind Ventures	closed			3,500	74	na	na	$21
Iberdrola	Community Energy	closed			2,000	30	na	na	$15
Energias de Portugal	Horizon Wind Energy	closed	722	778	9,000	2,93	$4,058	$1,953	$326
E.ON	North American assets	pending	210	880	6,000	1,953	$9,300	$1,792	$326

*N.B. Valuations are approximations based on publicly available information.

Source: company information

would gain from its pending acquisition of Airtricity. Each new project will be looked at on a case by case basis, he added.

Inevitably, when asset prices rise, asset owners begin to reassess their options. And recently rising prices have prompted several rumors that the remaining independent wind power developers, such as Invenergy, Noble Energy and UPC Wind, are up for sale.

In fact, Noble, which has 300 MW of wind farms under construction in New York State and another 3,700 MW in development, in March hired Goldman Sachs to explore strategic growth alternatives, "and we are still exploring our options," according to a spokeswoman for the company, based in Essex, Connecticut. UPC did not respond to phone requests for comment by press time.

Invenergy, founded by Michael Polsky who has built a reputation for successfully developing and selling power assets, has built up a considerable portfolio of wind assets. The company will only say that it has 12 facilities in operation and under construction in the US and Europe, adding that Invenergy has 1,900 MW worth of turbines, 700 MW that are set to be deployed in 2007, 600 MW in 2008, and 600 MW in 2009.

Some analysts in the industry say Invenergy has about 15,000 MW in its development portfolio, which would make for "astronomical" valuations. Nonetheless, Kevin Smith, Invenergy's senior vice president of development, says, "we have not entered into any discussions at this time, but we are getting a lot of phone calls."

But the United States is not the only target for large global energy companies. Some have even wider ambitions.

"The US is a bridgehead in a global market for renewable assets," said Jonathan Johns, head of renewable energy at Ernst & Young. That strategy is apparent in the plans of both Iberdrola and EDP.

Iberdrola is planning to spin off its renewable energy business in an initial public offering before year-end 2007. And EDP will likely not be far behind. "We are studying an IPO of our worldwide wind business in 2008," said Mexia.

In a climate in which concerns about global warming are in the headlines on a daily basis, an IPO could tap into those concerns and earn a multiple higher than the other parts of the business. While the issue is hot, some companies are likely to do well by tapping into those concerns. — *Peter Maloney*

COMPANY NEWS

Iceland America Energy enters US market with 49-MW geothermal project at Salton Sea

Iceland America Energy has begun developing geothermal projects in the US and in support of those activities officially opened its North American headquarters in Los Angeles on October 12. Iceland President Olafur Ragnar Grimsson spoke at the opening along with Los Angeles Mayor Antonio Villaraigosa.

The company holds a power purchase agreement with Pacific Gas and Electric to deliver power from the 49-MW Truckhaven geothermal plant it intends to develop near the Salton Sea in southeastern California. The company has just begun drilling the geothermal well for that project.

Furthermore, Iceland America Energy is negotiating with the City of Los Angeles to provide funding and technical assistance to the Los Angeles Department of Water and Power for its geothermal development project, according to Randy Howard, director of resource development and planning for LADWP.

Iceland America Energy CEO Magnus Johannesson said that in addition to the Truckhaven project, the company is developing a district heating project at Mammoth, California, in the Sierra Nevada Mountains. It is also looking at potential development opportunities in several states, including Nevada, Utah, Oregon and Alaska. However, it was too early to discuss them, he said.

Iceland America Energy Inc. was formed in 2004 by Reykjavik Energy Investors a subsidiary of a Reykjavik utility and Enex, also of Iceland. Additional shareholders include Feanaro and Dongell, Lawrence, Finney, both California companies.

Iceland has over 70 years experience in the use and exploitation of geothermal energy and renewable resources provide for 80% of its energy usage.

Energy Future Holdings calls in Goldman, J. Aron to hedge gas exposure of Luminant generation

Goldman Sachs and its power and gas trading arm, J. Aron, will be establishing a central role in the trading operations of Energy Future Holdings, formerly TXU.

In a form 8-K filing October 15 with the Securities and Exchange Commission, EFH said that a "key component" of its risk management strategy is a plan that involves both Goldman and J. Aron to hedge up to 80% of the natural gas exposure of generating affiliate Luminant Power's baseload generation output on a rolling five-year basis.

Moreover, the filing said that EFH intends to meet the future cash posting needs of its gas and power trading unit, Luminant Energy, by relying upon a new commodity collateral revolving credit facility that Goldman Sachs Capital Partners has agreed to syndicate.

Designing a hedge for 80% of natural gas exposure has a financial component to it. As the bankers syndicate their debt, the existence of the hedge can help assure investors.

On October 10, the private equity arm of Goldman Sachs, along with private equity firms Kohlberg Kravis Roberts and TPG Capital closed on their $33 billion acquisition of TXU (*GPR*, 11 Oct, 1).

According to the filing, members of the newly named EFH senior management team joined with their bankers during a New York meeting with investors launching the syndication of a total of $24.5 billion of senior secured facilities. Among the six Wall Street firms that have committed to raising funds for the new owners is the investment banking arm of Goldman Sachs.

Goldman has been in a similar position before. In 2004, it helped finance four private equity firms' purchase of generating company Texas Genco. As part of that deal, J. Aron became the off-taker, and marketer, of 25% of Texas Genco's baseload generation.

Since then, J. Aron has expanded its position in the Electric Reliability Council of Texas with off-take agreements for Horizon Wind Energy, which Goldman sold to Energias de

Portugal for $2.15 billion in March.

One banking industry source said that Goldman's involvement at what used to be TXU will be akin to what it was at Texas Genco. He noted that the same executives running the new EFH were the same who handled the Texas Genco acquisition and the profitable sale of Texas Genco less than a year later to NRG Energy. The source suggested that Goldman's role with Texas Genco helped add value.

The EFH generation affiliate, Luminant Power, with 18,365 MW of capacity, has 8,137 MW of baseload capacity, with 72% lignite- or coal-fired generation and 28% of nuclear generation. However, it also has 45 units with 10,278 MW of gas-fired capacity.

Designing a hedge for 80% of natural gas exposure has a financial component to it. As the bankers syndicate their debt, the existence of the hedge can help assure investors.

FINANCE

KGen Power's $1.3 billion acquisition of 1,859 MW from Complete Energy fails

Roiled capital markets appear to have sunk KGen Power's $1.336 billion acquisition of two plants totaling 1,859 MW from Complete Energy Holdings.

On October 15, the two small, privately held Houston-based power generating companies said they had mutually agreed that KGen would pay a $37 million break-up fee to Complete, rather than the $50 million fee that was stipulated in the original contract signed June 18.

A Complete spokeswoman said the company was not displeased with the busted deal, since it would receive cash with the break-up fee and would retain possession of two generating facilities whose value is benefiting from market conditions. It accepted less than the $50 million break-up fee to avoid arbitration and save time.

According to Lorin Cuervo, one of Complete's three founding managing directors, "We are delighted with the outcome. Considering the current trend in the energy industry, we feel greater opportunities lie ahead for Complete Energy now that this deal has been terminated."

Rhonda Hollier, the spokeswoman for Complete, said the company would continue to operate the only two facilities it owns: the three-unit 837-MW gas-fired combined-cycle Batesville facility in northern Mississippi, and the four-unit 1,022-MW gas-fired La Paloma station in McKittrick, California. Hollier said the company has not yet decided whether or not it will try to sell the plants again.

Daniel East, KGen's vice president of strategic planning and development, said the company pulled back from the deal for multiple reasons, but one of the main reasons was because of "things that are going on in the prevailing capital markets."

KGen's banker on the deal, Morgan Stanley, had not backed away from its commitment to finance the deal, according to East, however, given the liquidity crunch that hit the capital markets this summer, it is likely that the cost of financing the deal would have been higher, making it difficult for KGen to meet the closing deadline of September 19.

KGen chairman and CEO Gerald Lindner on October 15 said, "We believe that by not pursing this particular acquisition we can better maintain the flexibility of our balance sheet in a turbulent market and will be poised to take advantage of future opportunities with more attractive terms."

The other main reason KGen called the deal off was because of "unplanned and unexpected" outages "that were lengthy," which KGen said took place at both facilities between the time the deal was agreed to on June 18, and September 19, the day the deal was scheduled to be closed.

Complete's Hollier said that this was the first that Complete had heard such complaints from KGen. She said that "we met all the closing requirements. We are proud of our plants."

However, records show that one of La Paloma's four units was down when the deal was supposed to close, and one is down now in an unplanned outage.

Originally the deal was pursued by KGen as part of an expansion plan, mainly into the California market. The deal would have seen KGen assume long-term tolling agreements for most of the output for the two plants and would have allowed KGen to increase its generating capacity by 61%. The company owns five units at four facilities in Georgia, Mississippi and Arkansas, which have a combined capacity of 3,030 MW.

Complete, which was advised by Goldman Sachs, stood to make a nice profit from the sale. In August 2004 the start-up company paid NRG Energy $26.5 million in cash and assumed $300 million in debt to acquire the 837-MW Batesville facility. NRG Energy agreed to sell the facility nine months after it exited bankruptcy.

In August 2005, Complete paid a group of banks led by Citigroup and Societe Generale $560 million in cash for the 1,022-MW La Paloma facility. La Paloma was one of the assets that a syndicate of banks took possession of in late 2002 when PG&E National Energy Group went bankrupt. PG&E NEG was subsequently liquidated.

Complete is led by managing director Hugh Tarpley, a former executive vice president of mergers and acquisitions at Dynegy, as well as Cuervo and Peter Dailey, both formerly of Allegheny Energy Inc. Complete has 86 employees and retains Fulcrum Power Services of Houston to help operate its plants.

KGen Power has a 21-person executive staff and has retained a unit of Fortis Energy Marketing & Trading to manage its facilities.

In June, the company said it was interested in Complete's two facilities as part of an expansion plan designed by Lindner, its chairman, who was formerly with Alvarez & Marsal, a bankruptcy reorganization company, and East, who formerly worked at Dynegy (*GPR*, 21 June, 1).

KGen Power draws its lineage directly from two former distressed debt bond traders from Credit Suisse who formed private equity firm MatlinPatterson, which became a central player in NRG's bankruptcy reorganization.

In May 2004, Duke Energy, looking to reduce its merchant holdings, sold eight natural gas facilities in the Southeast with a combined capacity of 5,325 MW to MatlinPatterson for $475 million. MatlinPatterson asked Lindner to set-up KGen Power to run that business.

After disposing of some of those assets, KGen broke off from MatlinPatterson in December 2006 after issuing more than $700 million of stock through a 144A private placement.

Energy Future Holdings plans private sale of $2 bil senior notes to repay interim debt

Energy Future Holdings, formerly TXU, plans to sell up to $2 billion of cash-pay senior notes due 2017 in a private placement, the Dallas-based company said October 15.

Energy Future Holdings also said that subsidiary Texas Competitive Electric Holdings plans to sell up to $2.5 billion of cash-pay senior notes due 2015 in a private placement.

Net proceeds from each of the offerings will be used to repay debt under each of the companies' respective senior unsecured interim loan agreements, said Energy Future Holdings, which last week closed on the $45 billion acquisition of TXU (*GPR*, 11 Oct, 1).

Energy Future Holdings was formed by the private equity buyout group led by Kohlberg Kravis Roberts, TPG Capital and Goldman Sachs Capital Partners.

S&P, Moody's cut ratings on TXU and TCEH to speculative to account for $40 bil debt

Standard & Poor's Ratings has slashed the corporate credit ratings of TXU and its unregulated power supply unit Texas Competitive Energy Holdings four notches, from BB to B-, citing the planned capitalization program by Kohlberg Kravis Roberts and TPG under a leveraged buyout that closed October 10.

Also, as it had warned in March, Moody's Investors Service slashed TXU ratings several notches to a speculative grade, citing the proposed capital structure under the $45 billion leveraged buyout.

The S&P downgrade reflects the addition of about $24.5 billion in senior secured debt and $6.75 billion in senior unsecured debt at key subsidiaries, the rollover of about $8 billion of existing debt at subsidiaries and TXU, and the addition of $4.5 billion of senior unsecured debt at TXU, said S&P.

S&P, like Platts, is a division of The McGraw-Hill Companies.

Post-acquisition, TXU will have about $40 billion in adjusted debt, compared with about $12 billion at present, it added.

The rating is further negatively affected by the planned ring-fencing and legal provisions that the sponsors intend to structure around Oncor Electric Delivery, TXU's regulated transmission and distribution subsidiary, S&P added.

Reflecting those plans, S&P affirmed Oncor's corporate and senior secured rating at BBB-, its lowest investment grade, and moved it from CreditWatch-Negative to CreditWatch-Developing, because KKR and TPG plan to ring-fence Oncor to render it bankruptcy-remote from TXU. The outlooks on TXU and the other units are now stable.

"If TXU sells 20% of Oncor to an acceptable third party unaffiliated with the sponsors — which is the sponsors' intention — we would raise Oncor's corporate credit and senior secured debt ratings to BBB+ as long as the protective structure provides the minority shareholder adequate rights to prevent material change, including bankruptcy filings, of Oncor by TXU. If TXU does not sell the 20% stake in Oncor soon after the transaction closes, we will lower the Oncor rating to BB," S&P said.

TXU's ratings reflect a vulnerable business risk profile resulting from exposure to Texas' competitive electricity supply markets and commodity volatility that is only partially offset by regulated cash flows, S&P added.

"TCEH's wholesale unit benefits from 8,137 MW of low-cost coal and nuclear generation, as well as a good competitive position that will be further enhanced by the addition of about 2,200 MW of new coal capacity in the next three years. However, wholesale earnings are strongly related to natural gas prices and market heat rates, which we believe will be less favorable in the medium- to long-term than the company forecasts," S&P said.

"TCEH's continuing decline in retail customers also pressures the rating. For the year ended June 30, 2007, the number of retail customers declined by about 6%. We heavily discounted the company's strong forecast for retail customer growth in our analysis," it added.

In a "special comment" issued March 27, Moody's Vice President and Senior Credit Officer James Hempstead blasted the buyout as a "clear indication of the company's bias toward meeting shareholder needs to the obvious detriment of bondholders and creditors."

Moody's and Hampstead then followed through, lowering TXU's existing senior unsecured debt seven notches to Caa1, Moody's seventh-highest speculative grade, from Ba1. Moody's also assigned a new B2 corporate family rating to TXU, "reflecting our primary concern with the amount of debt being incurred at the company in relation to its sustainable cash flow generation over a long-term horizon," Moody's said, adding that it "does not anticipate any meaningful debt reduction over the next few years, which raises concerns over the amount of cushion incorporated into the business plan."

Moody's echoed S&P's belief that TXU benefits from attractive assets and businesses. "As a result, TXU's baseload facilities should be in a position to produce a significant amount of cash flow over the near- to intermediate time horizon," Hempstead said.

Senior unsecured ratings of power supply unit TCEH, formerly TXU Energy, were lowered eight notches to Caa1 from Baa2.

"In our opinion, the extreme leveraging of cash flows (primarily derived from TCEH's more risky generation operations) severely reduces the cushion and flexibility to avoid a potential default if an unexpected or adverse event were to impact the company's businesses," Moody's said. "This leverage of cash flows in the face of the operating, strategic, financial and environmental challenges currently facing this industrial sector only serves to exacerbate this concern," it warned.

Regulated transmission and distribution unit Oncor Electric Delivery's senior unsecured ratings was cut only two notches to Ba1, the highest speculative grade, from Baa2.

Cost of new nuclear build could be double the current market estimates, says Moody's

The cost of building new nuclear power plants in the US could be twice as much as existing estimates, said a report issued last week by Moody's Investors Service.

In the report, "New Nuclear Generation in the United States: Keeping Options Open vs. Addressing an Inevitable Necessity," Moody's said that the potential reactors could cost as much as $6,000/kW of capacity to build.

Moody's said it expects new plants to cost $5,000-$6,000/kW of capacity to build, compared with market estimates of $3,000-$4,000/kW of capacity. It noted that a proposed American Electric Power integrated gasification combined-cycle coal-fired power plant in West Virginia is expected to cost $3,500/kW of capacity.

Moody's said that, when assessing the cost of a new plant, it is concerned with the "all-in costs" of the facility, adding in capitalized interest, other owner's costs, such as site preparation, and transmission upgrades.

It likened its assessment of the costs to the difference between the basic purchase price of a house and the "all-in" price including the cost of appliances, furnishings and landscaping.

It said the prospects for building new nuclear generation in the US "are very good," noting that a "significant number of large, well capitalized companies are publicly discussing their plans to build" new reactors.

However, Moody's said it believes that "many of the current expectations regarding new nuclear generation are overly ambitious," citing the amount of time it will take to bring new plants online and underestimation of the cost of building the new reactors.

Moody's believes nuclear generation is a "critical component" in the energy supply mix, it said, but it does not believe more than one or two new nuclear plants will be online by 2015.

Regulated utilities will be in a more advantageous position to "commence construction over the intermediate-term horizon," Moody's said, adding that it expects the current 90% average capacity factor for nuclear plants to be maintained over the near to intermediate term horizon.

Regulated utilities can ascribe value to fuel diversity and environmental benefits that may not be available to merchant players, it said, adding that the risks associated with construction could be mitigated through "creative cost recovery designs that would not be available to a merchant operator."

Moody's foresees five potential areas of bottleneck for construction of new nuclear generation: lead times for "ultra heavy/ultra large" forgings, especially given the lack of forges around the globe capable of the work; large manufactured components; engineering resources; logistics, and site labor.

Standard & Poor's upgrades ratings on FPL wind project financing vehicles

Standard & Poor's has raised or confirmed its ratings on the debt associated with 1,230 MW of wind projects sponsored by FPL Energy.

S&P, like Platts, is one of The McGraw-Hill Companies.

The move follows a four-year study of the company's operational performance, said S&P.

Under analysis are the $380 million senior secured notes due 2023, which finance FPL Energy American Wind LLC's 697-MW, seven-wind farm portfolio, and which S&P upgraded to BBB from BBB-. The wind farms have "stable cash flow and a financial performance that is above our initial expectation," S&P wrote. The current bond balance is $287 million and the outlook is stable, according to the ratings company.

American Wind's farms sell their output under long-term power purchase agreements and earn further revenue through the monetization of federal production tax credits.

S&P said the wind farms had seen "several years of stable operations, reasonable expectations for wind turbine performance, and stable offtaker ratings."

As a result of the American Wind upgrade, S&P also upgraded from BB- to BB the $125 million senior secured amortizing bonds due 2017, on FPL Energy Wind Funding LLC, which is the holding company for American Wind LLC. Structurally subordinate to American Wind, Wind Funding repays debt from distributions it receives from American Wind.

The Wind Funding bond balance is $89 million and the outlook is stable, S&P said.

Furthermore, S&P affirmed its BBB- ratings on FPL Energy National Wind LLC's $357 million senior secured notes due 2024, on which the bond balance is $316 million.

National Wind is a portfolio of nine wind projects totaling 533.6 MW in eight US locations. "A generally stable cash flow and conservative base case assumptions for the wind resource support the stable outlook," S&P said.

"A rating upgrade is unlikely in the near term, because it would require additional assurances on forecasts of long term wind resources and turbine performance, consistent with long term forecasts," said S&P analyst Terry Pratt.

ASIA/PACIFIC RIM

Korea Electric to spend $1.43 billion to buy stakes in Russian and Chinese generators

Korea Electric Power Co. is planning to spend $1.43 billion to buy stakes in power companies in Russia and China.

A Kepco official said the company is planning to buy a 26% stake in TGK-4, a Russian power generator with 3,000 MW of capacity. The official said the discussions were at an early stage, and it was not clear when the transaction would materialize. "We are planning to spend up to $1 billion on this acquisition if it goes through," he said.

TGK-4, which was recently spun off from the state-owned power producer RAO UES, is a major power producer in Central Russia. Currently, RAO UES is the single largest shareholder of TGK-4 with a 47% stake. Retail and institutional investors hold the remaining stakes. RAO UES is looking to further reduce its stake by 26% and is planning to sell the stake to a strategic investor.

In China Kepco is planning to spend $430 million to buy a 34% stake in state-owned Shanxi International Electricity Group. The agreement is likely to be signed by the end of the October, said the official. "The agreement would give us ownership of around 3,200 MW through 24 coal-fired plants in Shanxi."

Of the 24 plants totaling 9,300 MW, 12 plants are in operation, three are under construction, and nine are in various stages of planning. The official did not break down the capacity of the projects in the different stages of completion.

Kepco, South Korea's monopoly power producer, owns 58,000 MW of capacity.

Philippines privatization agency says Suez has submitted highest bid for 600-MW plant

Philippines' privatization agency Power Sector Assets and Liabilities Management Corp. has declared Calaca Holdco Inc., a wholly owned subsidiary of Belgium's Suez-Tractabel SA, the preferred bidder for the 600-MW coal-fired Calaca plant.

PSALM said Calaca would be declared the winner as soon the agency could verify the accuracy, authenticity and completeness of the bid documents.

PSALM said Calaca submitted a bid of $786.53 million for the coal plant.

In the auction, conducted on October 16, PSALM said all the bidders submitted offers above the reserve price set by the government. PSALM did not disclose the reserve price nor the identity of the other bidders. A total of 18 investor groups indicated preliminary interest in bidding for the plant.

The price offered by Calaca Holdco for the plant is lower than the $930 million offered by AES Corp. for the 600-MW Masinloc plant (*GPR*, 2 Aug, 11). Analysts said the higher price for Masinloc was mainly because the quality of the power plant was better. Suez-Tractebel offered $606 million for the Masinloc plant.

Analysts said the success of the Calaca auction is proof of the growing international interest in the Philippine power market. Additionally, the allocation of a 287-MW power supply contract, or about 48% of the plant's rated capacity, attracted the bidders as it gives the new owner a ready market for the electricity generated by the power plant.

The Calaca plant was first offered to prospective investors in 2005, but the auction was canceled after two of the three qualified bidders backed out shortly before the deadline for submission of the offers. The second round of bidding, held in April 2006, was also declared a failure because the price proposals submitted by the two bidders were below the reserve price. Philippine-based companies First Generation Corp. and DMCI Holdings Inc. were the two bidders for the plant.

PSALM said that out of the 31 National Power Corp. plants identified for privatization, it has now successfully bid out 10 plants. In terms of capacity this works out to 1,675 MW or 39% of the total 4,336 MW of capacity in the Luzon and Visayas provinces.

India's Ministry of Power says 52,365 MW of targeted 78,577 MW are moving forward

India's federal Ministry of Power said that about two-thirds, or 52,365 MW, of the 78,577 MW it has targeted for completion by 2012 are moving forward.

In its 11th five-year plan, India budgeted $100 billion to build 78,577 MW by March 31, 2012.

The power projects are in various stages of execution, said the ministry. State governments have come up with proposals for some of the projects. Sites have been identified for some. Other projects have secured fuel and water linkages. And tenders offers for other projects have been released.

Overall analysts are of the view that the progress on most of the projects is at a preliminary stage. Ultimately for the projects to take off, the developers should be confident that they would be able to receive payments for the power they sell to the state electricity boards. In the past, many projects have not taken off because developers have been concerned that loss-making electricity boards would not be able to pay for the power delivered. Although India has improved its power distribution system in the last five years, it remains to be seen if power developers would be encouraged to do business with state-owned power distributors.

The ministry also said that coal mine allocations have been made for most of the thermal projects. More than 60% of the 78,577 MW of targeted projects would be fired by coal. The remaining 40% would be fired by gas, be hydro or wind powered, or be nuclear power plants.

The ministry also said the coal mine allocation has been made for 98% of the coal-fired projects planned in the 11th plan period. The coal projects also include the nine 4,000-MW "ultra-mega" projects.

"New players should be encouraged to accelerate the capacity addition and also generate competition in the interest of getting the equipment at competitive prices," the ministry said.

Currently state-owned Bharat Heavy Electricals Ltd. is the main power plant equipment maker in India. Its inability to deliver the equipment on time due to the high demand has prompted many Indian companies to order equipment from Chinese manufacturers.

Overall, the ministry has been working towards achieving the power target in the 11th plan period as the power sector needs to build capacity to support the country's rapid economic growth.

Analysts said a more active implementation strategy is needed from the Indian policy makers given that the country's power plans have fallen woefully short of target in the past. For example, in the five-year period that ended March 31, 2007, India built only 20,000 MW out of the 41,000 MW planned.

The delay in state governments sanctioning land, fuel to the power developers and the inability to negotiate workable power purchase agreements have been sited as the main reasons for the lack of progress on the projects.

India's NTPC, Bihar electricity board plan venture to build 1,980-MW coal-fired project

Indian state-owned power company NTPC Ltd. signed an agreement with state-owned Bihar State Electricity Board to form a joint venture company to set up a 1,980-MW power project.

Both NTPC and BSEB would have equal stake in the company, but no details were provided on the capital structure of the joint venture.

In a new release, NTPC said the joint venture would set up three 660-MW coal-fired plants at Nabinagar in Bihar. The company did not indicate the cost of the project.

NTPC said that 75% of the power produced at the plants would be sold to BSEB while the remainder would be sold to customers outside the state.

NTPC, a publicly listed company, has a current capacity of 27,904 MW through 26 power plants. BSEB is the monopoly power distributor in Bihar.

Analysts said the joint venture was not surprising as NTPC would like to bring in a local partner to develop power in the coal-rich Bihar State.

New Zealand's Contact Energy to develop wind farm with a potential of up to 650 MW

New Zealand's Contact Energy Ltd. plans to develop a wind farm with a capacity of up to 650 MW.

In a statement issued on October 16, Chief Executive David Baldwin said the project would be developed to the south of Port Waikato and would be called Hauauru Ma Raki. Baldwin said the proposed wind farm was strategically important, as it would be close to major load centers of Hamilton and Auckland. He said the final size of the wind farm was yet to be determined, but it had the potential to be up to 650 MW, depending on several factors, including landowner agreements and resource consents. Baldwin did not indicate the cost of the project.

"We have been developing this project together with Wind Farm Group over the course of 2007 and have been pleased with the response to this project from landowners and other stakeholders." New Zealand-based Wind Farm Group provides technical assistance in setting up wind farms.

"Hauauru Ma Raki is nationally significant both in terms of meeting New Zealand's growth in demand for electricity and for the development of clean, renewable electricity for current and future generations," Baldwin said.

Baldwin said if the full 650 MW of the project were developed, it could produce enough electricity to power approximately 250,000 homes and help avoid the production of around 1.2 million tons of carbon dioxide to the atmosphere per year.

Baldwin said Contact has decided to defer investment decisions on its consented 400-MW Otahuhu C gas-fired station in order to focus on renewable generation.

Baldwin said the proposed site for the Hauauru project is suited to a wind farm as it has a good wind resource and the surrounding areas are very lightly populated.

Separately, Contact also said it was planning to build a flexible, fast-start 100-MW gas-fired peaking plant at the company's Stratford power station. The plant is likely cost around $105 million and could be operating by 2009.

Contact Energy produces around 25% to 30% of New Zealand's electricity. Australia's Origin Energy Ltd. is its single largest shareholder with 51.4% stake. Retail and institutional investors own the remaining shares.

EUROPE/MIDDLE EAST

E.ON and Statkraft sign $6 bil agreement to swap shares and generation assets

German company E.ON and Norway's Statkraft last week signed a letter of intent to swap Statkraft's shares in E.ON Sverige, the Swedish arm of the German utility, in exchange for power generation assets and shares in E.ON.

The two companies said the total value of the asset swap was Eur4.4 billion ($6.2 billion). A final agreement is expected to be signed during the first quarter of 2008.

According to the agreement, E.ON will get 44.6% of the shares in E.ON Sverige currently held by Statkraft. This would give E.ON full control of its Swedish arm, which currently is owned 55.3% by E.ON and 44.6% by Statkraft. State-owned Statkraft and E.ON Sverige are the third and fourth largest power producers in the Nordic region, respectively.

E.ON said the deal would strengthen its position on the Nordic market and give it full ownership of power plants with a total capacity of around 6,400 MW, of which 40% is nuclear and 28% hydroelectric. The remaining 32% are oil, gas and renewable energy.

In return, Statkraft would get assets with an annual production of around 7 TWh to 8 TWh. These include 934 MW of Swedish hydro power plants and two gas-fired plants in Germany: Emden 4 and Feltheim with a combined capacity of 700 MW and with corresponding gas contracts.

Also in Germany, Statkraft would get a 220 MW pumped storage facility, 10 run-of-river hydropower stations totaling 42 MW and gas storage capacity of up to 100 million cubic meters/year. In addition, Statkraft would get a 10-year power purchase agreement in Germany, in excess of 100 MW, a 56-MW hydropower installation in the UK and district heating plants in Sweden and Poland.

Furthermore, Statkraft said the shares it would get in E.ON were expected to constitute a "substantial part of the transaction," representing more than 2% ownership in the company. This will make Statkraft one of the five largest owners in E.ON. However, the exact amount of shares in E.ON and other share-related issues remained to be detailed, it said.

The agreement must be approved by the relevant authorities and the board of directors of both companies.

Bard Mikkelsen, CEO of Statkraft, told Platts the negotiations with E.ON had been ongoing for around six months. He said Statkraft's share in E.ON Sverige was seen as a "financial position," which had been continuously evaluated. On acquiring shares in E.ON, Mikkelsen said this was a strategic move that would strengthen the partnership between the two companies.

Industry to lobby UK government against selective support for clean coal projects

A decision by the UK government last week to back only the post-combustion version of clean coal technology is set to be challenged, according to sources close to the proceedings.

Several clean coal plant developers and backers, including Centrica and Climate Change Capital, are lobbying UK industry and government to build support for their plans, which are based on the other, pre-combustion, version of clean coal technology.

The companies are understood to be mounting an industry-wide challenge to the government's decision.

The government's announcement last week will leave four planned clean coal projects high and dry without the prospect of government support, while five others are still in the running for the competition to obtain government funding.

According to Platts, the two most advanced projects by a clear margin are Centrica/Progessive Energy's proposed plant at Teesside, which is a pre-combustion loser, and E.ON's Kingsnorth project, a post-combustion winner.

It is estimated that post-combustion carbon capture technology is more expensive — around twice as expensive on a unit cost basis — than pre-combustion carbon capture technology.

Jake Ulrich, managing director of Centrica Energy, said, "Supporting just one carbon capture technology risks losing a golden opportunity to realize the Prime Minister's vision of the UK as a global pioneer of carbon capture.

"Excluding pre-combustion capture technology in favor of post-combustion capture technology means bypassing a cheaper method of capturing carbon that will have more international application in favor of a technology largely used to retrofit existing coal plant.

"The UK needs substantial investment in new power stations which should be built with pre-combustion technology, committing to carbon capture from the outset.

"This seems to be wasting an opportunity for the future and instead focuses on fixing existing coal plants, many of which will soon be retired," Ulrich said.

Ian Temperton, a managing director at specialist investment banking group Climate Change Capital, agreed that the government's decision to back only a post-combustion power plants with taxpayers' money was wrong.

He said, "This may be a fix for cleaning up existing power stations in the future, but we are about to build a new generation of plant."

"The government is basically telling power companies that they can keep building conventional high emitting coal plant and that the taxpayer will bail them out. It is folly to abandon other technologies," Temperton said.

Owners of 1,875-MW Teesside plant in UK consider future options, including possible sale

Investment bank NM Rothschild has been appointed by the owners of the UK's 1,875-MW Teesside station to carry out a strategic review of the plant, the company said October 16.

One possible outcome of the review could be the sale of the plant.

Teesside is currently majority owned by Carval Investors, the private equity division of Cargill, with 70%, while Goldman Sachs owns the remaining 30%.

The gas-fired plant began operating in 1992 and was initially owned by Enron. The plant was supplied with gas from the J-block field under a 15-year deal.

The 229-MW gas-fired Roosecote plant, which is of a similar vintage, was sold to Centrica in 2003 for £24 million (equivalent to £104/kW, or $211).

The larger Teesside plant might be sold for more as it could be attractive to bidders with deep pockets. Russia's Gazprom, for example, has expressed interest in breaking into the baseload power market.

E.ON receives permit to develop 1,200-MW gas project in England

The UK government has granted consent and planning approval for E.ON UK's 1,220-MW combined-cycle gas turbine Drakelow plant in South Derbyshire, the Department of Business, Enterprise and Regulatory Reform said.

Energy minister Malcolm Wicks said, "In consenting to this project I felt it was important that the potential for utilizing heat and capturing carbon emissions from the station is kept open and the necessary equipment is installed."

The project was consented to under section 36 of the 1989 Electricity Act and given planning permission under section 90 of the 1990 Town and Country Planning Act, DBERR said. But both approvals came with conditions.

As part of the section 36 consent, the government has included a condition to "ensure that carbon capture plant can be retrofitted should that be necessary in the future," the department said.

On the planning side, which was agreed with the local planning authority, E.ON must install "the necessary plant and pipeworks to ensure that the station can supply heat in the future, if the opportunity materializes," DBERR said.

In 2006, E.ON was granted permission to construct another 1,200-MW CCGT plant on the site of the existing Grain oil-fired station in Kent. The company also has plans to build two new 800-MW supercritical stations at its Kingsnorth coal-fired plant, also in Kent, and is conducting a feasibility study into building a clean coal power station at Killingholme in Lincolnshire.

RWE Npower plans carbon capture project, totaling $17 mil, at 1,500-MW plant in Wales

RWE Npower plans to design and build the first carbon dioxide capture pilot plant at a UK coal-fired power station, the UK subsidiary of Germany's RWE said last week.

The first phase could be fully operational by 2010 and would be built at RWE's 1,500-MW Aberthaw plant in South Wales. An initial £8.4 million ($17 million) investment will be spent on a 1-MW carbon capture plant at the site.

However, RWE says it is also planning to invest further money to support a carbon capture and storage demonstration plant of at least 25 MW. The site for the larger plant has yet to be determined, but RWE says it would form part of one of its planned supercritical plants. RWE is eyeing two sites for potential new supercritical coal build, Tilbury in Essex and Blyth in Northumberland.

RWE said that the pilot would enable it to develop a full understanding of both the technical and commercial issues relating to carbon capture and storage and would allow the CCS concept to be tested in as close to real operational conditions as is possible.

Both of the carbon capture plants would be designed using post-combustion technology which, unlike alternative CCS approaches, can be applied to existing coal-fired plants. The larger plant could be eligible for funding from the UK government's proposed clean coal generation and carbon capture and storage technology competition, RWE said.

The government's competition is set to be launched in November. More details, such as the size of the funding available and the time table, will be set out next year, according to a government spokesperson.

Irish regulators delay start of single market to ensure preparedness of participants

The two Irish energy regulators have delayed the go-live decision for the all-island Irish electricity market, also called the Single Electricity Market, a source said last week.

Regulators have long planned to officially start up the single market on November 1, and were expected to make a final decision on the start date October 11. However, the Northern Ireland regulator said that the decision would now be delayed until October 22 to ensure that all participants are ready to go.

"The reason for the delay is to maximize the information available to the regulatory authorities when they decide and announce the go-live date," said Iain Osborne, chief executive of the Northern Ireland Authority for Utility Regulation. Currently, however, the go-live date is still expected to be November 1, Osborne said.

Participants in the market have to undergo a self-certification process before a go-live decision can be taken. It is understood that following the initial examination of participant self certification returns, a number of "participant caveats" have been identified.

The single electricity market would make it easier to transport and trade electricity across the grids of Northern Ireland and the Republic of Ireland.

E.ON completes purchase of 69% stake in Russian generation company OGK-4

German company E.ON has completed the purchase of a 69.34% stake in Russian wholesale generation firm OGK-4 for Eur4.1 billion ($5.65 billion).

OGK-4 is one of a several assets being sold off as part of a sweeping reform of Russia's power sector (*GPR*, 20 Sept, 1).

The deal was signed by E.ON CEO Wulf Bernotat and the head of Russian power monopoly UES, Anatoly Chubais on October 15. It coincided with President Vladimir Putin's visit to Germany for talks with German Chancellor Angela Merkel.

According to E.ON's statement, OGK-4 runs four gas-fired plants and one coal-fired plant with total installed capacity of around 8,600 MW.

This amounts to roughly 6% of Russian thermal generating capacity, E.ON said.

By 2011, OGK-4 is planning to build additional power plants with a total capacity of 2,400 MW at its existing facilities.

Companies buying into the Russian power sector are bound by plans already drawn up by UES to increase Russia's generation capacity.

Russian state generation company OGK-6 postpones offering, citing market conditions

Russian wholesale generation company OGK-6 has postponed its new share placement because of unfavorable market conditions, Sergey Dubinin, financial director for Russian power monopoly UES, said last week.

The issue of new shares was planned to take place in November. Neither Dubinin nor a spokesman for OGK-6 would provide any new time frames.

OGK-6 is to publicly offer 11.8 billion new shares.

As part of the swap with the state-held shares, Russian gas giant Gazprom will hold a stake of 52% following UES reorganization by July 1, 2008.

After the new share placement, however, Gazprom's stake in the company can change depending on whether it participates in the respective share issues.

Gazprom, which now considers power generation a core business, has previously expressed interested in OGK-6, among other power assets being offered in Russia.

Fitch downgrades Enel rating to A from A+ following close of Endesa share purchase

Fitch Ratings has downgraded Enel's senior unsecured rating to A from A+ with a negative outlook on Enel's long-term issuer default, the credit rating company said last week.

"The rating actions follow last week's closing of the tender offer by Enel and Spanish construction company Acciona for the remaining 54% of the share capital of [Spanish utility] Endesa that they did not already own," Fitch said in a report. Following the formal completion of the transaction, Enel and Acciona hold 67% and 25% of Endesa and a shareholder agreement will come into play that allows both companies to jointly control Endesa.

According to Fitch, the downgrade of Enel's ratings reflects a weakening of its financial profile. The downgrade also takes into consideration Enel's growing exposure to more volatile markets, including its recent involvement in the Russian energy sector where, among other things, it intends to gain control of power generator OAO OGK-5 by increasing its current holding of 30%, it added.

The negative outlook on Enel's long-term IDR reflects challenges to jointly control and manage the enlarged group with Acciona, also taking into account the possible complexities of the shareholder agreement, Fitch said.

The rating agency said it intends to closely monitor progress regarding the planned sale of part of Endesa's assets — mainly those in Italy and France, as well as three Spanish thermal plants — and Enel's Spanish business Viesgo to Germany's E.ON.

Despite Enel's downgrades, Fitch acknowledges some of the benefits from the Endesa acquisition. "These benefits include exposure to the relatively attractive and fast-growing Spanish electricity and gas sector, generation asset diversification, and increased negotiating power," it said.

Fitch also downgraded Endesa's senior unsecured rating to A from A+. The outlook for Endesa's Long-term IDR is Negative. "The decision to align the ratings is a reflection of the strong control that Enel, in conjunction with Acciona, will exercise over Endesa at all levels, despite some conditions imposed by the regulator," Fitch said.

European Union could directly finance new nuclear projects, says EC commissioner

Direct European Union financing of new nuclear power plants, with loans from nuclear agency Euratom to plant developers, would not conflict with rules aimed at preventing market distortions in the EU internal electricity market, EC Energy Commissioner Andris Piebalgs said last week.

Responding to a question during a press conference, Piebalgs said Euratom loans fall under the separate 1957 European Atomic Energy Community Treaty (Euratom), not the broader Treaty of the European Union and "from that point of view [Euratom loans] can be used because that treaty is primary law" independent of the TEU, which governs competition matters in the internal energy market, Piebalgs said.

Between 1977 and 1987, Euratom loans helped finance 92 reactors or other nuclear installations in five countries: Belgium, France, Italy, Germany and the UK. But no loans have been made to an EU member state since 1987, shortly after the Chernobyl unit 4 nuclear power plant accident in Ukraine.

The Commission is expected soon to approve the investment by Bulgaria in a new nuclear power plant at Belene. Commission approval of nuclear investments is required under the Euratom Treaty. That approval would pave the way for an expected application from Bulgaria for a Euratom loan to help finance the construction of the unit. Commission approval of nuclear investments also helps pave the way for financing through the European Investment Bank, which this year announced it would again consider financing new nuclear plant construction.

Euratom loans can be granted for up to 50% of the project cost. Lithuania, which was forced to shut down its old Soviet-era reactors as part of the accession agreement when it entered the EU, is planning to build a new reactor, through a consortium with Estonia, Latvia and Poland, and may also be a candidate for a Euratom loan.

Israeli gov't. should use 'single buyer' model for competitive power market, says consultant

International consulting group KPMG has recommended that the Israeli government set up a state-owned company to purchase electricity from private power producers. The recommendation was made in a report to the Israel Electric Corp. and runs counter to previous recommendations and the current government strategy.

The proposal calls for a single buyer of electricity so that the entire network can be better managed. The report stated that the private power producers would be profitable under such a regime since the state would guarantee a minimum price. Until now the Israeli Finance Ministry has objected to direct government involvement in the private power sector, but there are growing concerns that the private power industry will face difficulties unless there is such involvement.

The Israeli National Infrastructure Ministry is considering setting up a state-owned company that would purchase natural gas for private power producers and then buy the electricity from them. But the idea has not been discussed so far with the Finance Ministry, which would have the ultimate say on the matter. The ministry believes that a state-owned company would encourage new players to enter the private power market.

European/Middle Eastern briefs

■ The all-island Single Electricity Market, merging the power systems of the **Republic of Ireland** and **Northern Ireland** in a common power pool, is due to start on November 1 this year.

The CER and the Northern Ireland Authority for Utility Regulation are running a separate consultation to work out how the requirements of the EU Electricity Directive 2003/54/EC can be met in the SEM, commencing with calculation of the required fuel mix information in 2009 for the calendar year 2008. "A proposed decision paper on this issue will be published in the coming weeks," the CER said.

■ Belfast-based **Viridian Group** last week said that it had completed its second generation plant at Huntstown in north Dublin, Ireland. The power station was commissioned on schedule and started supplying the national grid last week.

Huntstown-2 is a Mitsubishi-designed high-efficiency 401-MW combined-cycle gas turbine unit and represents Viridian's second major investment at the North Dublin site, following the commissioning of the 343-MW Huntstown-1 generation plant in November 2002.

■ Some 89 MW of wind power capacity has been added this year in the **Republic of Ireland**, taking the country's wind sector total to 803 MW, Irish regulator the CER said this week in a consultation on fuel mix calculations.

The regulator said the latest available system generation figures indicate an increase of just under 100 MW installed capacity on the Irish system since January 1, 2007. The figure does not include the October start-up of Huntstown-2 (see above).

■ London AIM-listed **Renewable Energy Generation** has sold its position in the 50-MW Tymien wind farm project in Poland to its equity partner Invenergy for a cash consideration of £10 million ($20 million), it said in a statement October 16.

The Tymien wind farm is on the Baltic coast and was completed on time and to budget in early 2006. REG invested £8.06 million into the project and dividends have totaled just less than £700,000.

■ Dutch company **Nuon** plans to start a pilot carbon dioxide capture project at its coal gasification plant at Buggenum the region of Limburg, the Netherlands.

The company signed a declaration of intent in April with the Ministry of Housing, Spatial Planning and Environment for a large-scale capture pilot project. The project will be subsidized by the government.

Carbon can be captured before the fossil fuel is combusted in this type of plant which leads to less loss of output and requires comparatively lower investments than capturing carbon post fuel-combustion, Nuon said.

■ HSBC has agreed to finance the $300 million, 560-MW project planned by **Dalia Power Energies** Ltd. in the Negev region of Israel.

Dalia Power has already signed a memorandum of understanding with Siemens for the supply of the equipment and to be chief contractor for the project. The plant would run on natural gas to be delivered via pipeline from the country's national transmission network that is now under construction. The power plant is due in service in 2010.

LATIN AMERICA

Suez Energy sells 256 MW from Estreito plant in Brazil in country's October 16 power auction

Suez Energy International has sold 256 MW average of power from its participation in the Estreito power plant at the power auctions held in Brazil on October 16.

The Estreito 1,087-MW hydroelectric project is being built by Suez Energy International, leader of the consortium with a 40.07% stake, in partnership with Companhia Vale do Rio Doce (30%), Alcoa (25.49%), and Camargo Correa (4.4%). The price obtained by SUEZ at the auction was real 126.57/MWh for 30-year indexed power purchase agreements.

Electricity from hydro and thermal projects was offered to distributors at the auction in contracts starting from 2012. Suez's partners in the project will consume their share of the output on their industrial sites in Brazil.

The Estreito concession was acquired by Suez Energy International and its partners in 2002. The plant is on the Tocantins River, between the states of Tocantins and Maranhão, downstream from the São Salvador 243-MW hydro project that Suez is also building and Cana Brava, a 450-MW hydro plant owned by Tractebel Energia, Suez Energy International's subsidiary in Brazil.

"We began construction of Estreito in January 2007, and this power purchase agreement will enable us to finalize the financial agreement with BNDES, completing the development of the most important hydro project under construction in Brazil today," said Mauricio Bähr, CEO of Suez Energy Brazil.

NORTH AMERICA

PROJECTS

CEC delays approval of 500-MW gas project planned by Edison Mission Energy near LA

The California Energy Commission has delayed its approval of an amended license for the gas-fired 500-MW Walnut Creek Energy Park, giving the South Coast Air Quality Management District time to review the project.

The "peaker" project, expected to cost between $220 million and $280 million, would be designed to meet peak load, particularly in the summer. Edison International subsidiary Edison Mission Energy owns the natural gas-fired combined-cycle project.

SCAQMD in August approved amended rules intended to increase the pool of scarce air pollution credits for power plants in the Los Angeles region. The credits, also known as offsets, are required under federal, state and local air quality rules.

Nine power plants have been proposed in the region, although it is "unlikely that all of them will be built," SCAQMD said in a statement after approving amended rules in August.

At the CEC meeting, a representative from SCAQMD said the agency needs to evaluate whether the Walnut Creek project should be allowed to buy pollution credits. The rules were amended because the agency is aware of a potential shortfall in new generation in the area, the representative said. The review will take a minimum of 30 days, the representative told the CEC.

Partners' withdrawal from South Dakota project, 630 MW, will likely delay regulatory approval

The recent withdrawal of two partners in the 630-MW Big Stone-II coal-fired power plant proposed for eastern South Dakota means final regulatory approval of the $1.6 billion project probably will not come at least until early next year.

In mid-October, the Minnesota Public Utilities Commission gave the five remaining partners the option of submitting an application for a smaller coal plant, of perhaps 500 MW to 550 MW.

Big Stone-II spokesman Dan Sharp said the partners essentially are considering three possibilities: downsizing, keeping the project at 630 MW, or attracting "another participating utility" to become a partner. "We've had several utilities express interest in it," he said, declining to identify the would be participants.

Currently, he said, the partners are "remodeling the [remaining] participating utilities' needs" with respect to Big Stone-II.

Minnesota-based Otter Tail Power is the lead developer. Other partners include Central Minnesota Municipal Power Agency, Heartland Consumers Power District, Missouri River Energy Services and Montana-Dakota Utilities.

In September, Great River Energy, citing environmental and other concerns, backed out of the project and another participant, Southern Minnesota Municipal Power Agency, said it may buy power from the plant but will not be an owner.

Sharp said those defections may delay the project somewhat, but they will not kill it.

Construction still is scheduled to begin next year, with the plant in commercial operation near Milbank, South Dakota, in late 2012.

Iowa board rejects proposed land annexation for 750-MW coal-fired plant planned by LS Power

Iowa's City Development Board last week rejected a plan by the city of Waterloo to annex 345 acres to accommodate a 750-MW coal-fired power plant proposed by LS Power.

In the wake of the board decision, Waterloo may resubmit its annexation request, or LS Power will need local approval for the plant from Black Hawk County.

LS Power is still reviewing its options, but the decision is not a deal-breaker for the project, Mark Milburn, LS Power project development manager, said last week. "The annexation into the city isn't absolutely required for the project," he said.

Annexation by the city would have given LS Power's plant access to city services like police and fire, and the plant would also pay city taxes, estimated at about $3.1 million a year.

The Waterloo City Council voted in May to annex the land for the roughly $1.5 billion power plant. Landowners representing about 80% of the land that was slated to be annexed supported the move. The City Development Board, however, decided October 11 that the city had not properly followed state rules on annexing land.

The City Development Board, part of the Iowa Department of Economic Development, reviews requests for municipal boundary changes.

LS Power, an independent power producer based in East Brunswick, New Jersey, plans to file within weeks applications for two key permits for the project, Milburn said. The company will ask the Iowa Utilities Board for permission to build the plant, and it will seek an air permit from the Iowa Department of Natural Resources, he said. Once the permits are filed, the IUB and DNR have six months to decide on the applications, he said. LS Power aims to start building the plant by early 2009, he said.

LS Power is in talks with various utilities about buying electricity from the plant. "There's a lot of interest," Milburn said. Typically, LS Power will not build the plant until all its capacity is accounted for by offtake contracts, he said.

Meanwhile, Interstate Power and Light, an Alliant Energy subsidiary, in July asked the IUB for permission to build a 630-MW coal-fired unit at its Sutherland Generating Station in Marshalltown, Iowa. After reviewing the application, the IUB asked for more information on the project, including the possible effect pending climate-change legislation in Congress could have on the plant. Central Iowa Power Cooperative and Corn Belt Power will own stakes in the new unit.

Developers submit plans for 679 MW of new coal-fired projects in Michigan

Michigan regulators have received applications from Wolverine Power Cooperative and the Holland Board of Public Works for new coal-fired generation projects.

Wolverine told the Michigan Department of Environmental Quality that it wants to build a 600-MW baseload plant at Rogers City, Michigan, near Lake Huron. The plant would use circulating fluidized bed technology, according to Craig Borr, executive director of the Cadillac, Michigan-based co-op.

Holland, meanwhile, is proposing a 78-MW coal unit to serve its internal load, said Judy Visscher, an environmental regulatory specialist with the city.

Wolverine's project is scheduled for commercial in 2012 or 2013, Borr said. There is no precise construction/in-service time table for the Holland project.

Visscher said it is possible the city ultimately may decide to join with other municipal electric systems in the upper Midwestern state and partner with Consumers Energy, a subsidiary of CMS Energy, in its 800-MW "advanced supercritical" coal plant proposed for Bay City, Michigan.

Consumers filed an air permit application for the $2 billion project with the DEQ on October 16. Consumers, which hopes to have the plant online by 2015, said it would probably need about 500 MW of the plant's output. The remaining 250 MW would likely be sold to municipal electric systems. A company spokesman would not identify any potential buyers, but said discussions were ongoing.

According to DEQ spokesman Robert McCann, the agency is reviewing three formal applications for coal plants. Earlier this year, LS Power submitted a permit request to build a 750-MW coal plant near Midland. LS Power merged with Houston-based Dynegy earlier this year.

Consumers has not yet filed a permit application with DEQ.

Bluewater Wind considers wind farm project offshore Maryland, based on Delaware model

Bluewater Wind is talking to Maryland officials about building a wind farm off of Ocean City, Jim Lanard, the company's head of strategic planning, said October 15.

The company, which was recently acquired by Babcock & Brown, is already fighting to develop a wind farm off of Delaware.

In Maryland, Bluewater has not made a formal proposal, but is talking with various "stakeholders," including state officials, local officials, environmental groups and community groups, Lanard said in an interview.

Bluewater has modeled an offshore wind park based on the 450-MW project it seeks to build off of Delaware, Lanard added. That wind park would include 150 towers, each incorporating a 3-MW turbine. The Delaware Public Service Commission earlier ordered Delmarva Power to negotiate terms with Bluewater, but the utility sued in state court, saying the contract would force it to buy power at a rate it did not want to pay.

In Maryland, the model puts the hypothetical wind farm 12 miles off of Ocean City, Lanard said. It has not yet determined the cost. In Delaware, Bluewater has estimated a $1.6 billion price tag, but Lanard stressed that the Maryland project would face different development costs and could not be assumed to cost the same.

There has been no commitment by state officials, "but everyone is interested and very excited," said Lanard.

"Offshore wind is an established technology in Europe, but unknown here," he commented. "We wanted to show what a possible wind park in Maryland could look like." The project would help meet Maryland's growing demand for power, he said.

The Maryland Department of Natural Resources recently forecast that the state's peak demand could rise from 14,935 MW in 2006 to a "high case" of 18,183 MW. The department presented that forecast during the Public Service Commission's July 26-27 Maryland Electricity Planning Conference. In addition, Maryland has a renewable portfolio standard that requires utilities and retail marketers to include 7.5% green power in their portfolios by 2018.

The office of Maryland Governor Martin O'Malley referred an inquiry to the Maryland Energy Administration, which did not return a telephone call by press time. Neither the Ocean City government nor the Ocean City Chamber of Commerce had anyone available to comment.

Meanwhile, Bluewater, based in Hoboken, New Jersey, is looking at other markets, said Lanard. In New Jersey, it will probably submit a proposal for a 350-MW "pilot" project that the state would oversee and partly fund. The Board of Public Utilities recently issued a solicitation for that project.

In New York, Bluewater hopes to hold discussions with the Long Island Power Authority about an offshore project there. The company had bid into a LIPA solicitation in 2003, but the state authority chose a 140-MW proposal by FPL Energy. Recently, though, LIPA's chairman said he wants to cancel that project because of an escalating cost estimate that would raise LIPA's power costs to $291/MWh.

Cape Wind project offshore Massachusetts faces new hurdle getting cables approved

The 420-MW Cape Wind project faces a new hurdle in its six-year battle to win permits, this time not over turbines that opponents say mar scenic views, but an invisible part of the project, under water transmission cables.

The Cape Cod Commission, a regional planning group in Massachusetts, plans to vote October 18 on the cable that runs 7.6 miles under a seabed in state waters and about six miles underground on land to connect the offshore wind farm to a utility switching station.

A subcommittee has recommended that the commission reject Cape Wind's application, saying the developer, Boston-based Energy Management, failed to provide enough information about the cable.

However, Mark Rodgers, spokesman for Cape Wind, said that the project is not going to provide any more information because the Cape Wind interconnection is already the most studied cable in Massachusetts history and is being held to a tougher standard than other power cables on Cape Cod.

The project has faced stiff opposition for years from wealthy property owners along Nantucket Sound who will have a distant view of the project's 130 turbines.

Phil Dascombe, a planner for the Cape Cod Commission, said that Cape Wind failed to provide several pieces of information, including a thorough study of the project's impact on eel grasses. "Cape Wind did extensive study on eel grass close to shore, but not all the way out to the three mile [state] limit. So that was information the committee felt it needed."

Project supporters see the committee's negative recommendation as capitulation to wealthy homeowners, many who fund an anti-Cape Wind lobby group that calls itself the Alliance to Protect Nantucket Sound.

Barbara Hill, executive director of Clean Power Now, a pro-renewable energy group said that a similar transmission cable built two years ago generated little controversy and quickly won approvals. That cable, built by National Grid, ran about 26 miles under the seabed from Nantucket Island to a land interconnection on Cape Cod.

The National Grid cable did not come up for a vote before the Cape Cod Commission because it did not meet any of the triggers for review, Dascombe said. Cape Wind did trigger commission action because it is undergoing state environment impact review. Cape Cod projects that require the state review come under commission jurisdiction, he said.

Should the full commission vote to reject Cape Wind's cable October 18, the developer can seek an override from the state Energy Facilities Siting Board. Cape Wind supporters are confident that Cape Wind will prevail at the state level because that board has already approved the project. They point to the siting board's decision last year to override a Cape Cod Commission decision rejecting a natural gas line proposed on Cape Cod by KeySpan. In that case, the board voted to override the Cape Cod Commission because it had already taken up many of the commission's issue. In addition, the siting board said the gas line would provide needed energy.

But even if Cape Wind prevails before the state, the override process will take time, meaning more delay for the project, a key strategy of opponents, Hill said. "It is an attempt to kill by a thousand cuts," she said.

Ontario Energy Board approves proposal to build grid link with 198-MW wind farm

The Ontario Energy Board has approved Canadian Renewable Energy's plan to build a 12.1-kilometer, 230-kV transmission line to connect its proposed 198-MW Wolfe Island wind farm at the head of the St. Lawrence River to the mainland grid operated by Hydro One, the regulator said.

The OEB said the project was in the public interest and would have no impact on transmission rates in the province. It added that the developer had consulted with the local community in the proper manner.

Canadian Renewable Energy is owned Calgary, Alberta-based Canadian Hydro. It expects the Wolfe Island project to cost C$410 million ($421 million). The wind farm has a 20-year power purchase agreement with the Ontario Power Authority.

Sky Harvest plans to expand to 150 MW from 50 MW its wind farm in Vancouver

The Sky Harvest subsidiary of Keewatin Windpower plans to triple the size of its proposed Matador wind farm in Saskatchewan to 150 MW, the Vancouver, British Columbia-based company said.

The expansion from 50 MW to 150 MW will be possible now that Sky Harvest has acquired rights to Saskatchewan government-owned land that is adjacent, said Chris Craddock, president of Keewatin. The company has secured funds for all pre-development work on the site, including meteorological studies of the wind resource, he noted.

SaskPower's transmission crosses the property so the wind farm would have access, the company said. The land at the proposed Matador site is used for cattle grazing and the government has determined that farming and wind power are compatible, Craddock said.

In March, Keewatin acquired Sky Harvest that has in development another 150-MW wind farm near Bersay in southwestern Saskatchewan. The developer is completing the environmental assessment and permitting of that project.

CONTRACTS

Dominion plans to pay $233 million to Exelon to exit purchase agreement with Ind. coal plant

Dominion said October 15 it will pay Exelon $233 million to end a below-market contract to sell power from its 515-MW coal-fired State Line Power plant in Hammond, Indiana, some five years early.

Richmond, Virginia-based Dominion, which said the power purchase agreement was scheduled to end in December 2012, hopes to close on the termination agreement by the end of 2007, assuming certain conditions are met, including Federal Energy Regulatory Commission approval and consents of third parties.

Once the contract has closed, Dominion said it would sell State Line's output into the PJM Interconnection regional grid.

"There is enormous value trapped in our Midwest generation fleet by below-market contracts scheduled to expire beginning in 2012," Dominion Chairman, President and CEO Thomas Farrell said in a statement.

"This transaction will unlock some of that value ahead of schedule. Although State Line's capacity is less than 20% of the total Midwest fleet, the contract termination is expected to add more than $30 million of after-tax earnings annually. That is a good indication of the total value yet to be realized from this part of Dominion's merchant generation portfolio," he said.

Mark Lazenby, a company spokesman, declined to say whether Dominion would be seeking early terminations of similar contracts.

Farrell said that as a result of the agreement with Exelon, the company had raised its 2008 operating earnings per share outlook of $6 or more per share to $6.10 to $6.25 per share.

Seminole Electric Co-op signs agreement to increase purchases from wood-fired plant

Seminole Electric Cooperative, the Florida co-op group, said this week that it has signed a contract to increase the amount of power it buys from a waste wood-fired plant in Liberty County to 32.5 MW from 12.5 MW as part of a broader effort to increase Seminole's purchase of renewable energy.

The extra 20 MW will be delivered to Seminole's 10 member co-ops starting in 2010, when plant owner Telogia Power completes a planned expansion. The newly signed contract runs to November 2023; Seminole did not disclose financial terms of the deal.

Seminole also said that it has signed a contract to purchase 1.6 MW from Timberline Energy LLC, which will build and operate a landfill gas-fired plant in Hernando County. That contract starts in February 2008 and runs through March 2020; again, financial terms were not disclosed.

Seminole said that with the two new deals it is under contract to buy more than 100 MW of renewable power. Florida Governor Charlie Crist in July issued an executive order that calls for the state's Public Service Commission to implement a requirement that power suppliers in the state secure 20% of their needs from renewable sources by 2020.

SECONDARY MARKETS

TransAlta Power to sell its 404-MW stake in six plants to Cheung Kong of Hong Kong

TransAlta Power on October 15 said it plans to sell its 404-MW net interest in six Canadian power plants to Cheung Kong Infrastructure Holdings of Hong Kong for C$629 million (US$645 million).

The deal provides Cheung Kong "with an entry to the North American market and a platform to further expand in the region," said Eirene Yeung, secretary of the Hong Kong based company that invests in energy, transportation and water. "The company has long seen Canada as an important market offering attractive investment opportunities. The acquisition reflects the company's strategy of investing in infrastructure opportunities around the world, leveraging the group's strong financial positions and solid experience in infrastructure," said Yeung.

Cheung Kong is a unit of the Hutchison Whampoa conglomerate controlled by billionaire Li Ka-shing, whose investments in Canada include a majority stake in Husky Energy of Calgary. Cheung Kong also operates in China, Australia, the UK, and the Philippines.

Calgary, Alberta-based TransAlta Power's plant ownership is through its 49.99% interest in TransAlta Cogeneration that has net interests of 815 MW in five gas-fired cogeneration plants in Alberta, Ontario and Saskatchewan and a coal-fired plant in Alberta. The plants have a total capacity of 1,362 MW, and the power is sold under long-term contracts to various parties.

TransAlta Power is separate from TransAlta Corp., which has interests in 50 plants totaling 8,500 MW in Canada, the US, Australia and Mexico.

TransAlta created TransAlta Power in 1998 and transferred

TransAlta Power's generation holdings

- 54-MW interest in the 108-MW Mississauga, Ontario, plant that sell power to the Ontario Electricity Financial Corp.
- 34-MW net interest in the 68-MW Ottawa, Ontario, plant that sell power to the Ontario Electricity Financial Corp.
- 34-MW net interest in the 68-MW Windsor, Ontario, plant that sell power to the Ontario Electricity Financial Corp.
- 35-MW net interest in the 118-MW Fort Saskatchewan gas-fired plant in Alberta that sells power to Dow Chemical
- 55-MW net interest in the 220-MW Meridian gas-fired plant in Saskatchewan that sells power to SaskPower
- 192-MW net interest in the 770-MW Sheerness coal-fired plant in Alberta that sells power into the Alberta grid

three of its wholly owned gas-fired plants in Ontario to the new entity. TransAlta then sold 49.9% of TransAlta Power to the public and retained the remaining 50.1% in its TransAlta Cogeneration subsidiary.

The $645 million price represents a 15.7% premium over the October 12 stock closing price, said TransAlta Power. Cheung Kong has offered C$8.38 in cash per unit or share. TransAlta Power would pay a C$17 million, if it backs out of the deal. The sale is expected to close by year end.

Back in May TransAlta Power announced that its board was considering a sale due to proposed changes in Canada's tax laws that did away with some of the tax benefits of Canadian income trusts.

The sale was needed, said TransAlta Power, because unit holders currently receive tax credits that reduce their income tax. The credits will no longer be available to unit holders when the revision to the tax law takes effect in 2011.

TransAlta Power lost C$52.4 million in second-quarter 2007 as a result of a C$54 million non-cash charge to earnings resulting from a new federal tax law. Income for the quarter, excluding the tax charge, was C$1.6 million on revenues of C$83.7 million. Plant availability was 90.5%.

The sale requires approval of two-thirds of the TransAlta Power unit holders, as well as some regulatory approvals. BMO Capital Markets served as financial advisor.

Affiliate of ArcLight Capital closes acquisition of Progress Ventures' power trading platform

ArcLight Energy Marketing last week said that it closed its acquisition of the commodity trading and marketing platform of Progress Ventures. In announcing the deal's completion, ArcLight also said it had hired key managers to head up the energy marketing unit.

ArcLight has hired Robert Adrian to be the CEO of AEM. He was head of commercial operations at Progress Energy Ventures, and also worked at TECO Power Services, Cinergy and Occidental Petroleum.

AEM's CFO will be Philip Chesson, who was previously chief risk officer at NRG and Williams.

The chairman of AEM will be Steve Bergstrom, formerly COO at Dynegy.

"We're excited to begin implementing ArcLight Energy Marketing's unique value proposition," Adrian said. "AEM combines experience and reputation in the physical and financial commodity markets, as well as the financial debt and investment markets."

AEM is based in Raleigh, North Carolina, and has offices in The Woodlands, Texas.

AEM is indirectly owned by ArcLight Liquid Energy Opportunities Fund, which is managed by ArcLight Capital Partners. The firm announced the acquisition back in July. Founded in 2001, ArcLight Capital Partners is an investment firm with more than $6.8 billion under management.

Earlier this year, Progress Ventures sold 1,855 MW of gas-fired generation assets in Georgia to a fund managed by ArcLight Capital Partners. At the time, Progress also sold forward natural gas and power contracts to Constellation Energy Commodities Group, netting Progress Energy $480 million in proceeds, Progress Energy said.

Progress Energy divested the trading unit as part of a corporate strategy to sell non-core assets and focus on electric utilities in the Carolinas and Florida, said spokesman David McNeil.

A representative from ArcLight did not respond to a request for an interview by press time.

Brookfield Power closes on purchase of 7.4 MW of hydro assets British Columbia

Brookfield Power last week closed a deal in which it acquired two hydroelectric generating facilities in northeastern British Columbia from East Twin Creek Hydro.

The Gatineau, Quebec, company, which comprises the power generating and marketing operations of Brookfield Asset Management, did not disclose the purchase price.

The two run-of-river facilities near the communities of McBride and Valemount have a combined installed capacity of 7.4 MW and produce about 29 GWh/year. Brookfield Power said the facilities complement its existing renewable power generation portfolio in British Columbia, which now includes five hydro stations on five river systems.

All the power the facilities generate is sold under long-term purchase agreements with BC Hydro.

SOLICITATIONS

Puget Sound Energy files draft solicitation for 1,340 MW of power supplies by 2015

Puget Sound Energy on October 12 filed a draft request for proposals seeking 1,340 MW by 2015.

Puget expects to issue a final RFP in January with responses due by the end of February.

Puget said a vibrant economy, expiring power purchase deals and an influx of customers is triggering its need to seek new power supplies. Puget expects a 412-MW deficit by January 2008, which could grow to 1,300 MW by the winter of 2014-2015, and reach 2,600 MW by 2025.

The Bellevue, Washington-based company is also planning a separate solicitation process for proposals to reduce its power consumption by 318 MW by 2015 from a combination of energy efficiency and fuel conversion.

Puget said the solicitation for power supplies is open to all plant sizes, technologies and fuels, except for coal and nuclear.

Puget said it would consider the transfer of development assets, construction of a project that then would be transferred to Puget or a sale of an existing asset.

From the 2011-2012 period onward Puget would look for power from gas-fired plants. That is the time frame when some of Puget's large power purchase contracts with utilities that own hydroelectric dams on the Columbia River expire or dwindle in size.

On the wind front, Puget said it needs to acquire 1,000 MW by 2020 to meet mandates of a new Washington law that calls for utilities to source 15% of their power from renewables by 2020.

Puget also would consider power purchases of varying contract lengths, seasonal exchanges, and capacity products including operating reserves to meet peak winter loads.

Puget is wrestling with whether or not to own generation that can be rate based or to purchase power under contract. “Decisions would be based largely on what makes the most economic sense and how a deal is structured,” said utility spokesman Roger Thompson.

Projects selected through an RFP would need to be approved on an individual basis by the Washington Utilities and Transportation Commission before costs could be included in rates, said Doug Kilpatrick, the UTC’s senior engineer.

A public meeting will take place October 29 to explain the RFP requirement. Contact Sheri Maynard at sheri.maynard@pse.com or Roger Garratt, director of resource acquisition and emerging technologies, phone 425-462-3470.

For the energy efficiency RFP, address questions to pseEES@pse.com or Carolyn Tash, energy efficiency services, phone 425-456-2601. Parties have until December 11 to file comments.

Details are available at www.pse.com/energyEnvironment/pse2008RFP.aspx.

Okla. Municipal Power issues solicitation for peaking capacity from 2008 to 2011

Independent power companies, power marketers and others active in and around Oklahoma have until October 30 to submit proposals to the Oklahoma Municipal Power Authority’s newly issued solicitation for peaking capacity and energy during the summers of 2008, 2009 and 2010.

In the request for proposals issued October 11, OMPA said that it is seeking offers to provide 75 MW of peaking power from June through September 2008, 85 MW to 115 MW during those months in 2009, and 100 MW to 155 MW during those months in 2010.

OMPA, which secures power for 35 municipal utilities, said that it would consider offers for both “5x16” and “5x4” power. It also said it “will entertain capacity bids in [lesser] amounts ... if, in the opinion of the authority, it can successfully combine multiple proposals to meet its capacity requirements.”

The muni group added, “OMPA will only consider proposals that can be secured and delivered with firm, network or point-to-point transmission service to the delivery area points.” OMPA is part of the Southwest Power Pool.

OMPA said it would use various pricing structures, including “fixed, variable based upon fixed heat rate and a relative published natural gas index price ... or call options, or any combination thereof.”

The RFP is available at www.ompa.com. OMPA said that it expects its board of directors to approve the winning contract or contracts on November 8.

In a related development, the OMPA board last week approved a plan to explore the possibility of repowering and expanding an older, gas-fired plant at its Ponca City power station. If OMPA were to decide to proceed with the repowering and expansion of the 36-MW plant, the incremental output of the facility would help the muni group replace its 76-MW share of the now canceled 950-MW Red Rock coal plant, said Drake Rice, OMPA’s director of member services.

The Oklahoma Corporation Commission last week rejected applications by Public Service Co. of Oklahoma and Oklahoma Gas & Electric to secure regulatory pre-approval for the Red Rock project, and PSO, OG&E and OMPA terminated their agreement to build the $1.87 billion coal plant (*GPR*, 13 Sept, 1).

OMPA’s Rice noted in addition to studying the possible repowering of its Ponca City plant, the muni group will be exploring other power-supply options — possibly including the issuance of an RFP for long-term power supply — and will decide later which would be best.

Snohomish PUD gets 10 proposals, 1,000 MW, in response to renewables RFP for 100 MW

The Snohomish County Public Utility District received 10 proposals representing 1,000 MW in its solicitation for 100 MW of renewable energy, a company official said.

“We’re extremely encouraged by this response,” said spokesman Neil Neroutsos, spokesman. “The bids were mainly for wind but we also received proposals for biomass and small hydro.” Any contracts signed will be for 20 years. The bids were due October 1.

The PUD did not release names of bidders. But a pre-bid conference in August was attended by representatives from 19 companies, including PPM Energy (owned by Iberdrola), Horizon Wind Energy (Energias de Portugal), GE Energy, enXco (owned by Electricite de France), Eurus Energy (owned by Tomen and Tokyo Electric), and UPC Wind Management.

In July, Snohomish issued a request for proposals for renewables to meet continued customer growth, anticipating its average retail load would grow to 924 MW by 2020 (*GPR*, 26 July, 14). Its winter peak is 1,400 MW.

The PUD also wanted to comply with a new renewable portfolio standard law that requires utilities to have 15% of their portfolio from renewables by 2020, Neroutsos said.

A tentative schedule is for a short list of bidders by November 13 and a final selection December 3. The utility said that the types and number of proposals received often drive the RFP schedule so sponsors should be prepared to hold the terms and conditions of proposals up to February 28, 2008.

NCPA issues solicitation for up to 58 MW of renewable resources, landfill gas supplies

The Northern California Power Agency intends to release a request for proposals on October 22 that will seek proposals for the sale to NCPA of up to 58 MW of eligible renewable resources and landfill gas supplies.

The RFP will be limited to those parties that have rights in, own, or propose to develop an eligible renewable resource electric generating facility or facilities, or own and operate landfill facilities. The scheduled RFP response date is November 5.

Copies of the RFP can be obtained by sending an e-mail to

Dana Griffith, power coordination and planning engineer at NCPA, at dana.griffith@ncpa.com. Include contact information and put "NCPA Green RFP" in the subject line.

Located in Roseville, California, NCPA is a joint powers agency that provides support for the electric utility operations of its 17 member communities and districts in Northern and Central California. NCPA owns and operates several power plants. NCPA was founded in 1968.

MARKETS & GRIDS

Calif. ISO selects centralized capacity market to meet state's resource adequacy requirements

The California Independent System Operator has chosen the centralized capacity market, or CCM, proposal by the California Forward Capacity Market Associates as being "the most favorable design" of four submitted plans to create a capacity market in the state by 2010.

Cal-ISO's decision will be reviewed by the California Public Utilities Commission, which is considering adopting one of the four proposals as a means to develop a mechanism to meet state obligations on resource adequacy. A decision on whether or not to create a CCM is expected to be approved or rejected by the CPUC in late February.

CFCMA comprises FPL Energy, NRG Energy, Reliant Energy, San Diego Gas & Electric and Southern California Edison.

A "significant factor" in deciding to back the CFCMA proposal was that only it among the four plans "provides for a multi-year forward assessment of the capacity that is actually committed to serve the needs of the Cal-ISO control area," the ISO wrote in a review of the four proposals last week. The paper explains why the CFCMA plan appears to Cal-ISO to be the best CCM proposal it reviewed.

"Our mission was to render an opinion on the alternative CCM designs," said Lorenzo Kristov, the ISO's principal market architect, who wrote the ISO paper. "We had to decide what was most important to the ISO, which was being able to see a commitment of the capacity that would be built in the market far enough out that we could plan around it. The other plans would give us either a year's notice or one-month's notice, which just isn't enough."

A second contributing significant factor in the ISO's preference for the CFCMA proposal is its approach to market power mitigation, which the ISO "believes will be critically important in local areas of the grid."

The ISO paper makes it "perfectly clear" that it is "not taking a position that the CPUC should or should not adopt a CCM." Instead, the results of its study should be read as a response to a "much narrower hypothetical question that if the CPUC decides a CCM should be implemented for California, what would be the preferred conceptual design of such a CCM," Kristov wrote.

In choosing the CFCMA plan, the ISO hedges its support by saying there are parts of it that deal with design details that "deserve much greater assessment and debate," and therefore could not be resolved at this time.

Nancy Ryan and Matthew Deal, advisors to the CPUC president, met October 1 to discuss the CFCMA plan with Colin Cushnie, director of regulatory affairs for SoCal Ed; Alan Comnes, director for NRG Energy; Mark Smith, director for FPL Energy; and Katie Kaplan, a consultant for Reliant Energy.

IPP MMC Energy withdraws three units from Cal ISO spinning reserve program

New York City-based independent generator MMC Energy said this week it is pulling its three generation units from the California Independent System Operator's spinning reserve service in protest of what it says is an "uncertain regulatory environment."

MMC has three generators in Chula Vista and Escondido, California, that generate a total of 110 MW.

Spinning reserve providers are the power plants that Cal-ISO keeps ready to provide power in a few minutes' notice during peak power times when on-hand generation is outstripped by demand and more power is needed immediately.

This issue came about because Cal-ISO said in a June 4 proposal that it intended to clarify spinning reserve certification. In that proposal, the ISO said that in the past year it had identified a few instances in which aggregated units that sold spinning reserve capacity to the ISO were not able to perform fully to the dispatch instructions.

In a September 20 statement clarifying its June 4 white paper, the ISO said that of the approximately 300 aggregated resources that participate in its markets, it is the configuration and spinning reserve bidding practices of six aggregated units "that have caused the concern under review." Those six units represent a total of 217 MW.

"This is a very small part of our system, but we want as much spinning reserve as we need. If all six pull out of the spinning reserve program, we will find a way to replace it. This is 217 MW out of a system that this time of year runs about 32,000 MW," said ISO spokesman Gregg Fishman. He said the ISO policy would not allow the identification of the six units.

In its September 20 paper, the ISO noted that one stakeholder requested that the ISO undertake a comprehensive system analysis of the adverse impact on resources that will be barred from providing spinning reserve under the June 4 ISO proposal, and to determine if remaining resources will be capable of supporting current and expected load. The ISO responded that it "does not believe that such an analysis is warranted. The limited objective of the FERC filing of attaining compliance by six host/CT aggregations to existing CAISO Tariff requirements does not necessitate system-wide economic analysis."

In its June 4 report, Cal-ISO said that in the instances identified, "either a portion of the awarded spin capacity was not synchronized to the grid or the aggregated units were not able to dispatch all of the awarded spin capacity to energy within the required 10-minute period."

Karl Miller, MMC's CEO, said the company would only bid on non-spinning reserves until Cal-ISO clarifies with the Federal Energy Regulatory Commission its June 4 white paper in which it "called into question the facilities' qualification to provide spinning reserves."

Andrew Brown, an attorney with Ellison, Schneider & Harris of Sacramento, California, wrote the ISO in response to its white paper for a client he said wants to remain unidentified. Brown said October 16 that the white paper and the follow-up ISO paper "appear to be changing the rules in the middle of the stream." He said the "technical requirements for the spinning reserve product have been changed in such a way that seems to discriminate between different technology types and plant configurations."

Brown said the "bottom line is that the ISO used to look at plants with more than one unit in the aggregate, but now wants to look at each unit on its own."

PJM sees rise in long-term capacity prices, RTO cites auction under reliability pricing

Transmission constraints and growing demand pushed up capacity prices in the eastern part of the PJM Interconnection, the regional transmission organization said last week, releasing its latest auction results.

The RTO completed its third auction under the Reliability Pricing Model, for long-term capacity, covering the period June 2009-May 2010.

PJM credited the RPM process for stimulating new generation and demand-side management and for keeping more power output in the pool rather than being exported for higher prices.

For most of PJM, the capacity price dropped to $102.04/MW-day, compared with $111.92/MW-day in the earlier auction for 2008-2009. PJM credited more capacity for that decline.

But prices rose in the Southeastern Mid-Atlantic region, which is equivalent to the Southwestern Mid-Atlantic Area Council, including Baltimore Gas & Electric and Pepco. There, the RPM price rose to $237.33/MW-day, compared with $210.11 in the earlier round. PJM blamed that increase on demand growing more quickly than supply. There was also pressure from environmental costs, said Andrew Ott, vice president for markets, during a news conference.

Auction prices ran $191.32/MW-day in a new sub-region that combines Eastern MAAC and Allegheny Power, and which includes New Jersey, eastern Pennsylvania utilities and Delmarva Power. For Eastern MAAC alone, which was a separate sub-region in the last bidding, the price was also $191.32/MW-day, Ott said. That shows an increase from $143.51/MW-day in the previous auction, and PJM blamed transmission limits.

For the 2009-10 period, PJM will have an additional 9,017 MW. Ott credited the RPM process, saying the certain, long-term capacity prices have stimulated new generation and convinced several generators to restart some old plants that had been mothballed. At the same time, generators are exporting less power.

"People used to tell us, 'I can't afford to keep my generation in PJM. I have to export it,'" he said. But exports have dramatically dropped, from about 4,000 MW in 2006-2007 (before RPM) to 1,600 MW/year in both 2007-2008 and 2009-2009. And in the 2009-2010 period, the trend has reversed, so that PJM will actually be a net importer of 300 MW.

Since the RPM process began, 2,589 MW of new generation have been added, according to PJM, which stated, "RPM sends signals that attract resources to the areas where they are most needed." In addition, generators have withdrawn requests to retire 646 MW of plants, Ott said.

The latest RPM auction cleared about 140,000 MW of generation, including existing and new plants, as well as 893 MW of demand response.

Retail suppliers seek real-time pricing for customers of last resort in Connecticut

Competitive retail suppliers are urging Connecticut to follow the lead of Maryland, New York and Pennsylvania by requiring real-time pricing for last resort customers.

The Retail Energy Supply Association called on state regulators to require the new pricing structure for Connecticut Light & Power's last resort customers, those with a demand of more than 500 kW.

"The benefits of real-time pricing are recognized by leading economists throughout the nation. Most notably, by delivering accurate price signals, real-time pricing fosters greater participation in energy conservation and demand response program," RESA said. "It also arms customers with the information to make informed choices about products and services offered by competitive electricity providers and spawns innovation in the marketplace."

RESA proposed the real-time pricing plan in a brief last week before the state Department of Public Utility Control, which is considering tariff changes to comply with a broad-based energy bill signed in June by Governor Jodi Rell.

The new law creates programs aimed at reducing the state's high electricity rates, which as of July averaged 15.76 cents/kWh. Among other things, it requires that utilities offer voluntary real-time pricing for all customers by January 1.

Grid owners, operators note widespread effects of renewables, demand response on business

Power grid executives gathered this week in Washington to highlight progress and development potential at the regional transmission organizations, with a special emphasis on demand response and renewable energy, two of the most politically popular resources.

The ISO/RTO Council issued a report on infrastructure development and congestion management as well as reports on demand response and renewable resources. It charted the growth of demand and the efforts of the grids to cope through expanded transmission, generation and demand response.

Executives from seven RTOs, speaking for the council and their regional markets, had the advantage of a good year behind them, with record demand peaks, wholesale grid reliability and declining prices during 2006. The unspoken disadvantage was the persistent background rumble from many public power officials and large industrial customers frustrated by the price volatility and short-term focus of the organized markets.

More than 100,000 MW of new generation were added during 2001-2006 within the RTO territories, the council reported. Transmission upgrades in the RTOs reduced congestion costs by hundreds of millions of dollars during 2006, the council said.

"I think what's going to drive us more than anything else is climate change issues," said Gordon van Welie, president and

CEO of ISO New England. Those issues will drive a need for renewables, and the renewables will drive a need for transmission upgrades, he said.

It has been difficult for RTOs to insist on transmission upgrades for economic rather than reliability reasons, but the executives said that is changing, partly because of evolving policies at the Federal Energy Regulatory Commission.

"I think we've already seen a change," van Welie said. "I think FERC through its reforms is going to place a greater emphasis on this. … The discussion is shifting to economic upgrades."

"That absolutely is going to change," said Nick Brown, president and CEO of the Southwest Power Pool.

The greatest obstacle to economic upgrades has been cost allocation, said Brown and Craig Glazer, vice president of federal government policy at the PJM Interconnection. But piece by piece, those parts of the puzzle are being put in place either by FERC orders or RTO stakeholder agreement.

Demand response within the RTOs reached 23,120 MW as of the spring, an amount that represented about 4.5% of demand, the council said. A PJM analysis concluded that a 3% load reduction could save Mid-Atlantic grid customers as much as $300 million a year.

The ISO/RTO Council provided a chart of wholesale price declines during 2006 from 2005, weighted to reflect the number of megawatt hours consumed at different price levels. The declines were about 32% in Ontario, 28% in the Electric Reliability Council of Texas, 21% in ISO New England, 20% in New York, 18% in the California Independent System Operator, 16% in the PJM Interconnection and 14% in the Midwest Independent Transmission System Operator.

The prices of natural gas, a significant part of the fuel mix for power plants, generally declined in 2006 from the preceding year, which saw hurricanes Katrina and Rita disrupt gas supplies.

An exception in the price trend was Alberta, where generation retirements sharply cut reserve margins and pushed prices up about 15% during 2006.

Idaho regulators approve contract for wind developer to pay grid costs

Idaho regulators approved October 15 a contract for Energy Vision, developer of two wind farms, to pay part of the $2.15 million costs to upgrade transmission to deliver energy over Idaho Power lines.

The adjacent Bennett Creek and Hot Springs wind projects have contracted to sell Idaho Power a total of 20 MW when the projects go online in December 2008. The wind farms are near Mountain Home in Elmore County.

Development company owner, Glenn Ikemoto of Piedmont, California, would pay 25% of the transmission costs. The payment is not reimbursable. Ikemoto would fund up front 50% of the costs that would be reimbursed over time. Idaho Power ratepayers would pick up 25% of the costs.

By agreeing to bear its share of the transmission costs, Energy Vision would receive firm transmission access, the Public Utility Commission said. The wind farms are qualifying facilities under the Public Utility Regulatory Policies Act.

The assignment of costs balances the benefit between Idaho Power customers and the developer, the PUC said. The developer should pay some costs because the QF plants are the cause for the timing and construction of the transmission upgrade. This also creates an incentive for developers to consider economic efficiencies when siting projects, the PUC said.

RENEWABLE ENERGY

Colorado governor plans emissions cuts in state through renewables, demand-side management

Colorado Governor Bill Ritter is developing a plan to cut greenhouse gas emissions in the state, largely through steps that can be made under the governor's authority.

Ritter, a Democrat, expects to release a "preliminary action plan" by early November laying out how the state can reduce its carbon dioxide emissions, Heidi VanGenderen, the governor's climate change advisor, said in an interview.

Many elements of an action plan have already been started under the governor's goal of creating a "new energy economy," an issue he campaigned on in 2006. This year, Ritter pushed for and signed 20 energy-related bills, such as doubling the state's renewable portfolio standard to 20% by 2020 for investor-owned utilities while requiring cooperatives to meet a 10% threshold, VanGenderen said.

Other new state laws aim to increase demand-side management, foster transmission development and boost funding to help emerging technologies make it to the market, VanGenderen said.

Ritter's action plan will likely focus on steps that can be taken under his authority, rather than needing to go through the Legislature, VanGenderen said. Earlier this year, Ritter issued two executive orders aimed at "greening" the state government. The orders call for cutting energy use in state buildings by 20% by 2012.

In a step that could help utilities reduce carbon emissions, Ritter wants to see if utility energy efficiency programs can be more profitable for the companies, VanGenderen said.

Ritter is now getting input from various stakeholders on elements that should be included in a GHG action plan, according to VanGenderen, who is spearheading the effort to draft the action plan. The governor held a series of round tables to get advice on steps that should be taken to cut GHG emissions, she said.

While declining to offer specifics because the governor's action plan is still being developed, VanGenderen said Ritter probably would prefer to give the state's current 20% RPS more time to work before increasing it.

Stakeholder advisory group says Utah should join regional emissions cap-and-trade program

A broad stakeholder group recommended that Utah join a regional cap-and-trade program and significantly increase its renewable supplies in an effort to cut greenhouse gas emissions.

The Blue Ribbon Advisory Council on Climate Change, with state, legislative, industry and environmental representatives, was appointed in 2006 by Utah Governor Jon Huntsman, a Republican. In its report issued last week, the panel found that there is no scientific doubt that global warming is occurring and that there is "very high confidence" that it is caused by human activity.

The report laid out 70 options for cutting GHG emissions. "The policy options are ambitious but achievable if the necessary resources are provided to implement them," the report said.

Rocky Mountain Power, a PacifiCorp utility, participated on the panel and is already adopting some of the recommendations, such as boosting its use of renewable energy, said David Eskelsen, a company spokesman. Rocky Mountain Power expects to own or buy under contract 452 MW of renewable resources by the end of the year, he said. In addition, it plans to add 2,000 MW of renewable capacity by 2013, he said.

Electric generation is the largest source of carbon dioxide emissions in Utah, accounting for 37% of total emissions, the report said. Among various "high priority" options for cutting GHG emissions, the report called on the state to set reduction targets and join a cap-and-trade program or institute a carbon tax. "We recommend that the state continue to work on a market-based strategy, including considering the implications of regional cap and trade, carbon tax, product excise tax and hybrid approaches," the report said. "A cap-and-trade program and a carbon tax are not mutually exclusive, and both could be implemented as part of an effort to reduce GHG emissions and achieve a particular target." The report also called for more renewable energy in the state, which has very little.

California's new renewable pricing benchmark may boost revenues for renewable plant owners

Western Wind Energy Corp. on October 15 revealed that a new pricing structure designed for renewable power contracts by the California Public Utilities Commission will increase its revenues 30% annually. However, the company must renegotiate its existing contracts if it is to see increased revenues.

Western Wind operates 34.5 MW of wind resources in California and plans to add 150 MW to its portfolio.

Nancy Rader, executive director of the California Wind Energy Association, said the 2007 market price referent approved by the PUC on October 4 applies to all new or renewing contracts for renewable resources signed by investor-owned utilities. She said contracts are limited by the MPR in force in the procurement cycle in which they were signed.

The MPR is the proxy price for a baseload combined-cycle gas turbine which the utilities, in effect, use as an upper price limit for selecting renewable power projects to satisfy their renewable portfolio standards.

For example, according to the resolution published by the PUC (E-4118), the 2007 MPR for 20-year projects coming online or having contracts renewed in 2008 is $95.72/MWh. For projects with new contracts in 2010, the price is $98.40/MWh. MPRs also vary according to the length of the contract and the online dates. For example, the MPR for a 10-year project coming online in 2008 is $92.71/MWh.

Rader said the MPR only reflects price certainty. In past procurement cycles utilities have been selecting bids and signing contracts at prices under the current MPR. A utility is also free to select projects bidding over the MPR if it needs the renewable resource. The developer can then apply for supplemental energy payments that are awarded by the California Energy Commission to bring the price paid by the utility down to the MPR.

Western Wind said the MPR prices will increase revenues for its operating assets in Tehachapi and San Gorgonio Pass over the current average pricing by at least $2 million annually if it is able to renegotiate its contracts.

Jeff Ciachurski, CEO of British Columbia-based Western Wind, said the company is negotiating new pricing for its existing contracts and hopes to renegotiate contracts it has already signed for 150 MW. It signed a contract with Southern California Edison in 2005 for the 50-MW to 120-MW Windstar Project in Tehachapi. It also holds a contract for the 30-MW Mesa expansion project with an unnamed utility.

California's renewable portfolio standard requires all load-serving entities, with the exception of municipal utilities, to acquire 20% of their electricity from renewables by 2010.

California irrigation district, partners intend to upgrade power lines to tap geothermal power

The Imperial Irrigation District intends to upgrade transmission capacity by up to 1,600 MW in the Salton Sea area of southeastern California in order to export new renewable resources via the proposed Green Path North and Green Path Southwest projects being developed by IID, Citizens Power and the Los Angeles Department of Water and Power.

The upgrades include a new 32-mile, 230-kV transmission line, running east-west through the heart of the geothermal resource-rich area where up to 2,000 MW of untapped geothermal resources are located. Additional work will include system upgrades of key interconnection facilities. The cost and time line have not been announced, according to IID spokesman Kevin Kelley.

Randy Howard, director of resource development and planning for LADWP, explained that LADWP, in partnership with Citizens Energy, will be building Green Path North in several segments with a completion date of 2013. He said that both the north and the south paths, together known as Green Path Central, will need to be completed by 2011, if the utility is to start exporting renewable resources from the Salton Sea area.

Howard said LADWP, the Southern California Public Power Authority and IID are jointly working on the development of a geothermal plant on jointly owned land in the area. LADWP has already signed contracts for exploratory drilling on the property.

Kelley said the district has been speaking with geothermal operators in the area already and there is enough interest to proceed. Furthermore, there are wind and solar projects being developed in the area that will need the new transmission capacity to export power.

Vince Signorotti, an executive with CalEnergy, a subsidiary of MidAmerican Energy Holdings, said IID's transmission upgrade project is absolutely essential. CalEnergy owns 10 operating geothermal plants in the Imperial Valley/Salton Sea area that generate about 326 MW.

CalEnergy has abandoned its plans to build the 215-MW Salton Sea VI geothermal plant that won California Energy Commission certification in December 2003. Instead it intends to develop one to three 50-MW projects. Signorotti said the company thought there would be economies of scale in building a larger plant, but the costs of commodities, especially high metal prices, erased any escalating economies of scale.

CalEnergy intended to build the 230-kV line in partnership with IID, and held a power purchase agreement with the district for the power generated by the Salton Sea VI plant. With the dissolution of those plans, IID will now develop the line on its own. It will recoup development costs through interconnection agreements with new developers based on a new open access transmission tariff, Signorotti said.

Mass. agency schedules third auction of renewable energy certificates for 2008

Evolution Markets will auction 25,000 renewable energy certificates on October 24 in a forward market sale on behalf of a quasi-public Massachusetts agency.

Announced October 15, this will be the Massachusetts Technology Collaborative's third forward auction of RECs. The certificates tend to sell at high prices because they are in short supply in Massachusetts.

The state agency will offer 25,000 new certificates that will be generated in the first, second, third and fourth quarters of 2008. The certificates will be auctioned in four lots of 5,000 certificates each, and five lots of 1,000 certificates each.

The certificates will come from Schiller Generating Station Unit 5, a repowered biomass facility owned by Public Service of New Hampshire. The RECs are expected to be created and delivered under a forward collar option agreement with the MTC.

Andrew Kolchins, director, Environmental Markets, said he expects a "significant response" once again from the auction, which will provide "another important data point" and "significant transparency to the market."

Certificates are in short supply in Massachusetts because few large-scale renewable projects have been built in New England. Yet demand is growing for renewables because of state renewable portfolio standards. Massachusetts requires that 3% of the electricity sold by retail suppliers and utilities come from renewables. The standard will increase 0.5% per year until 2009, when it will begin going up 1% per year until the state suspends the program.

An auction notice and forward sales agreement are available for the October 24 auction through Evolution Markets and on the MTC web site, www.mtpc.org. No exceptions or counterproposals to the terms of the purchase and sale contract will be considered, and no post-bid acceptance contract negotiations are permitted.

Questions about the auction must be submitted in writing to Ian Springsteel at the MTC at springsteel@masstech.org or 508-870-0312, by October 19 at noon. Questions will be answered in writing by October 22 at 5 pm. All questions and responses will be posted on the MTC web site.

Bids are due to Evolution Markets by telephone before 1:45 pm EDT on October 24. Bidders will be given the opportunity to improve upon the best bid by 2 pm. Bids must be binding until 5 pm on the day following the auction. Once a bid or bids have been accepted by MTC, Evolution Markets will inform the successful bidders, issue transaction confirmations, and then announce the auction results to the market.

The contact is Andrew Kolchins, Evolution Markets: 914-323-0257 or akolchins@evomarkets.com.

UN Secretary General backs carbon trading, calls on business leaders to participate

UN Secretary General Ban Ki-Moon urged US business leaders to endorse carbon trading as a "major economic opening" during a speech last week to the US Chamber of Commerce in Washington.

"You should view it as an opportunity to be rewarded and recognized for doing the environmentally sound thing," Ban said.

He rejected the notion that voluntary trading programs will work, given that the "business as usual" attitude would increase the severity of the results of climate change.

"Innovative market mechanisms are one way of addressing climate change," he told the chamber in remarks released by the UN after the speech. "I hope you will approach the carbon market as a major economic opening, one that has tripled in size to $30 billion in just the past year alone. An expanded and improved carbon market is an essential part of the solution."

While Ban's comments were eventually made public, the discussion he had with business leaders was closed. Companies and organizations in attendance included the American Petroleum Institute, Aramco Services, Hyundai, Cargill, Toyota, Chevron, and Northrop Grumman.

Ban described it as a "very useful" meeting in a briefing afterwards. He said that as long as businesses recognize they "require clear, predictable and long-term rules," they should get behind a clear emissions reductions program.

"You have to help fashion an agreement that is clear, has a long-term horizon, and utilizes market mechanisms and businesses," Ban said of any future international climate agreement.

"Your need for clear rules, and your willingness to work towards a solution to the problem of climate change, needs to be clearly communicated to the negotiators and decisionmakers who are set to gather at the UN Climate Change Conference in Bali" in Indonesia in December, he added.

The Bali meeting will be the formal negotiating forum for a successor to the Kyoto Protocol.

REGULATION & LEGISLATION

White House threatens to veto legislation on renewables mandates, energy tax incentives

While Senators voiced confidence that a compromise energy bill will emerge this year, House members this week vowed to buck a renewed veto threat from President Bush on legislation that contains a mandatory renewable portfolio standard and tax policies that "single out specific industries."

In response to the October 15 letter from the White House listing the president's concerns about the energy bill, Drew Hammill, a spokesman for Nancy Pelosi, the Speaker of the House of Representatives, said she "expects the administration to play a constructive role in finalizing a bill that will be sent to the president this year."

"The speaker has been encouraged by her discussions with the president on the need for a comprehensive and bipartisan energy bill to increase our national security, reduce the emission of greenhouse gases, and promote renewable fuels that reduce our dependence on foreign oil," said Hammill.

During a Capitol Hill news conference, Representative Edward Markey, a Massachusetts Democrat and others, including House Democratic Caucus Chairman Rahm Emanuel of Illinois, decried the latest veto threat over the energy bill and its tax incentives.

"We welcome the battle with the White House," said Markey. "With prices at $88/barrel, this is not the time for the president to do more for oil companies. It's time for the president to do more for the American people."

Markey and the other Democrats said the bill, including provisions that take away $15.3 billion in tax incentives from the oil industry and direct most of the funds to pay for new incentives to promote alternative and renewable technology and production, is necessary to reduce dependence on foreign oil.

In a letter to Pelosi, a California Democrat, Allan Hubbard, the president's economic policy adviser and director of the National Economic Council, warned Congress against passing an energy bill with its proposal to shift $16 billion in tax incentives away from the oil industry to finance incentives to boost development of renewable energy and alternative energy production.

Hubbard also said the bill must not contain a RPS that mandates a percentage of retail electricity from utilities be generated from renewable sources and any fuel economy standards for cars and trucks must be separate, "based on sound science" and carry a cost-benefit analysis.

The House bill, H.R. 3221, contains an RPS requiring investor-owned utilities to source 15% of their retail power from renewable resources by 2020. The Senate bill, H,R, 6, includes a 35-mile per gallon corporate average fuel economy standards for passenger vehicles and light trucks by 2020.

The House passed $16 billion worth of tax incentives with its energy bill in August while the Senate failed to attach a $32 billion tax package to its energy bill earlier this summer. Both tax measures would use the billions raised from tax breaks first given to the oil and natural gas in 2005 to provide financial incentives to nascent renewable energy resources.

Opponents to the energy bill within the Senate have sidelined a formal conference where members from both chambers would draft compromise legislation to pass then send to the president for his signature. As a result, members and staff have entered informal talks on bill.

Senate Finance Committee Chairman Max Baucus, a Montana Democrat, said in an interview that he believed an energy bill with a package of tax incentives could pass Congress but how large a package remains subject to discussion.

"I'm quite certain we're going to enact an energy bill with a significant tax package," said Baucus. "We're talking — the House and the Senate — about what those provisions might be."

Lieberman, Warner to present climate bill, including mandatory GHG emissions caps

Senators Joe Lieberman and John Warner plan on October 18 to introduce a comprehensive bill to address climate change with a mandatory cap on greenhouse gas emissions and a market mechanism to aid industry compliance, a congressional aide said October 15.

Lieberman also plans to hold a hearing on the bill October 24 in his global warming subcommittee, on which Warner serves as the senior Republican, said Warner spokesman Jonathan Murphy. A markup on the legislation in which the panel of senators would amend and report to the full committee is expected in the final week of October or early November, he said.

Senate Environment and Public Works Committee Chairwoman Barbara Boxer, a California Democrat, has said the bipartisan bill will serve as the bipartisan vehicle for moving a climate bill out of her committee and to the floor of the Senate.

Lieberman, a Connecticut Independent Democrat, and

Warner, a Virginian, in August unveiled a legislative proposal that called for incremental caps on greenhouse gas emissions starting at 2005 levels in 2012. The ultimate cap proposed would be 70% below 2005 levels by 2050. Their proposal covered 80% of industry emissions, including those from power plants, transportation and large industrials.

The Lieberman-Warner proposal also created an emissions allowance program whereby emitters could buy and sell allowances to help meet the growing emissions cap. Sectors would be given some initial emission allowances but later would have to buy them in an auction designed to pressure emitters to reduce their contribution to global warming.

Calif. representative Waxman asks FERC for details of its climate change initiatives

Representative Henry Waxman, a California Democrat who chairs the House Oversight and Government Reform Committee, has asked the Federal Energy Regulatory Commission to detail its efforts to combat climate change in view of the agency's broad authority over the energy sector.

In an October 11 letter, Waxman asked FERC Chairman Joseph Kelliher for details about FERC's climate change policy and its efforts to support actions that promote renewable energy, enhance energy efficiency, and reduce emissions of greenhouse gases.

"States have led the way in taking aggressive measures to combat climate change," Waxman told Kelliher. "Twenty-five states have adopted renewable electricity standards, which require increasing percentages of the electricity supplied to consumers to come from renewable sources."

"California and 11 other states have adopted standards requiring cars and light-duty trucks to limit greenhouse gas emissions but are awaiting EPA approval to enforce these standards," Waxman continued, adding that the "federal government "is just beginning to act."

In addition, Waxman said in his letter that "Congress is currently considering an energy bill that would establish a federal renewable electricity standard, strengthen federal fuel efficiency standards for automobiles, and tighten energy efficiency standards" and that he believes FERC should play a vital role in addressing climate change.

"From efforts to change the structure of our electricity markets to siting of electricity transmission lines and oil and natural gas pipelines to the approval of liquefied natural gas facilities and licensing of hydroelectric facilities, FERC is making decisions every day that will affect our nation's ability to halt and reverse global climate change."

Waxman asked Kelliher to describe, among other things, his agency's climate-change policy and how it was developed; what weight FERC gives to global warming in its permitting, licensing, siting and approval decisions; how FERC assists state governments to promote renewable energy, enhance energy efficiency, and reduce GHG emissions; and what steps FERC is taking to prepare for federal regulation of greenhouse gas emissions and federal renewable electricity standards

Waxman asked for a response by October 22.

Government should offer tax credit to carbon capture and storage, says study

Congress should enact a carbon sequestration tax credit and the private sector should create a carbon capture and storage trust fund to ensure that the technology can be used by power plants within a decade, a new study concluded.

The study, issued October 9 by the Carnegie Mellon Electricity Industry Center, said the CCS tax credit is an important part of a strategy to "increase US energy independence through use of its abundant coal resources in an environmentally clean manner."

Lawmakers must also continue the federal enhanced oil recover tax credit of 15%, the study said.

Congress should pass a separate tax credit for the building of CO2 pipelines because the current infrastructure is inadequate to facilitate CCS on the scale that is needed to address climate change, according to the study.

Current CCS projects represent roughly 50 million metric tons of CO2 equivalent used for enhanced oil recovery, while one coal plant on average will generate between 3 million and 4 million mt of CO2e, the study said.

Consequently, the existing pipeline system in the US must be between 10 times and 40 times larger to accommodate large-scale CCS, the study said.

These and other policies are needed if the US is to make "significant progress" on controlling GHG emissions from coal-fired power plants at a reasonable cost, according to the Carnegie Mellon study.

Other recommendations from the study include adding low-carbon coal facilities to the list of those eligible for EOR production tax credits; expanding the Department of Energy's testing program for CCS to represent 10 sites and between 3 million and 5 million metric tons of CO2e yearly, and working with businesses to create a CCS trust fund, a CCS investment fund and a CCS registry.

EPA commits to developing guidelines on underground storage of carbon dioxide

The Environmental Protection Agency last week committed to developing guidelines for permanent underground storage of carbon dioxide by the summer of 2008. Drafting the regulations has been ongoing inside EPA for some time, but the announcement marks the first commitment to complete the work.

The changes would expand the Underground Injection Control program which regulates all underground injection of substances. The UIC program is run by EPA and was created under the Safe Drinking Water Act.

The regulations are needed to determine who would take liability and responsibility for permanently stored carbon dioxide. Carbon dioxide would be captured from power plants and other industrial facilities and then stored in geological structures underground.

"This proposal will deal strictly with underground injection practices," EPA spokeswoman Enesta Jones said. "It does not get into carbon credits or any potential regulation of CO2."

Under the UIC program, carbon dioxide is already regulated under two well categories. Under class II well rules, CO_2 is regulated for its use in enhanced oil recovery wherein CO_2 is pumped into oil wells to displace additional oil.

In addition to the EOR wells, permanent sequestration well tests, though few in number in the US, are part of the class V experimental well category.

Another option EPA officials have discussed would be to create a new class VI well specifically for permanent carbon storage.

Following the rule proposal in 2008, there will be a public comment period. EPA said that it would issue the final rule between 2010 and 2012.

Transmission owners, utilities in MISO ask FERC to backtrack on grid reimbursement plan

Integrated-utility transmission owners and transmission-dependent utilities in the Midwest Independent Transmission System Operator have asked the Federal Energy Regulatory Commission to reverse a September decision allowing transmission companies in Michigan and Wisconsin to reimburse new generators 100% of the cost of upgrades associated with interconnecting them to the grid.

Last month FERC approved a proposal by Independent Transmission Co. and sister company Michigan Electric Transmission to reimburse generators for the cost of network upgrades. FERC, in a separate order, sent American Transmission Co. back to the drawing board to make its proposal look more like ITC's.

The transcos said their applications would "level the playing field" for renewable generators, which would otherwise have to absorb the cost of the network upgrades, which can be a disincentive. In the end, both plans will recover 50% of the reimbursement costs from all MISO customers and 50% from the transcos' pricing zones.

The same utilities that fought the plan that the transcos introduced in August are back at FERC asking for rehearing. Because ATC has not submitted changes to its plan, at issue in the requests for rehearing is ITC's plan.

The Michigan Public Power Agency wants FERC to maintain the existing cost allocation methodology whereby the interconnection customers fund 100% of the costs of network upgrades up front and then are reimbursed for 50% of those costs if the generation project meets certain commitment requirements.

MPPA said FERC "erred" in approving ITC's plan by "failing to explain its departure from prior decisions" that had rejected ITC's reimbursement plan. "Instead, the commission incorrectly relies on its policy in Order No. 2003 allowing transmission providers flexibility in proposing alternate recovery methods for generator interconnection upgrades."

MPPA added that the scheme would place a higher cost burden on Michigan consumers than other Midwest ISO customers pay. Michigan customers will also have the burden of bringing complaints to FERC "if improper subsidization occurs," MPPA said.

In that, FERC is "shirking its duty" from Order 2003 of protecting transmission providers' existing transmission customers, the group said. Finally, ITC's plan does not come with the assurance that the reimbursement policy that will supposedly encourage generation will actually bring generation that will benefit the transmission customers paying for transmission upgrades, MPPA said.

Consumers Energy said FERC erred by relying on Order 2003 without recognizing that it does not apply to this proceeding. Detroit Edison also disagreed with FERC's reliance on Order 2003. FERC erred in finding that ITC's "cost reimbursement eligibility criteria" are just and reasonable.

Detroit Edison said ITC's proposal "exposes applicants' own transmission customers to the very real risk that they will be paying in full for network upgrades constructed solely to serve" customers outside of their pricing zones, "a result this commission emphatically eschewed in Order No. 2003," the company said.

Detroit Edison wants transmission customers to have access to all cost and system specification data underlying network upgrade expenditures subject to generator reimbursement.

Finally, Detroit Edison said FERC should have imposed a dollar cap on the network upgrade costs eligible for reimbursement to affected interconnecting generators.

In its September order, FERC said there should be no cap of additional reimbursements that could be necessary for a generator at the time of interconnection.

Schwarzenegger signs legislation to promote cogeneration of less than 20 MW in California

California Governor Arnold Schwarzenegger on October 14 signed a bill designed to encourage the development of small cogeneration systems in California to help reduce greenhouse gas emissions.

The bill, A.B. 1613, by Assemblyman Sam Blakeslee, requires utilities to purchase electricity from cogeneration facilities, but applies only to systems of less than 20 MW.

The bill calls for rates to be "ratepayer indifferent," meaning ratepayers should not be required to pay higher costs because of the facilities.

The California Public Utilities Commission will need to establish limits on the amount of electricity that utilities would purchase from cogeneration systems.

The California Energy Commission by 2010 must adopt guidelines requiring cogeneration systems to operate efficiently. The capacity of the cogeneration systems would count towards load serving entities' resource adequacy requirements.

Blakeslee said he believes the bill will help spark increased use of cogeneration facilities by schools, hospitals, hotels and other customers.

Although utilities may view cogeneration as a form of competition from customers, California's climate law and power needs helped draw support for the measure, he said. "Everyone appreciated that it was just the right thing to do and the right time to do it, to foster technology that reduces GHG emissions while bringing new power online," he said in an interview last month.

FERC rejects SPP method of granting grid access to external generators; seeks 'dynamic scheduling'

The Federal Energy Regulatory Commission this week told the Southwest Power Pool to come up with a better method of allowing external generators to participate in the grid operator's real-time market.

The method proposed in August by SPP unjustly assigned all of the cost of implementing the new system to the external generators, the commission said in explaining its rejection of that plan. FERC gave the regional transmission organization 60 days to file an alternative proposal.

At the same time, the federal regulator questioned SPP's plan to use "pseudo ties," or interconnections that move power from an external balancing authority to a balancing authority in SPP. Consider using dynamic scheduling, FERC said.

In fact, dynamic scheduling is the only realistic alternative, according to Leslie Dillahunty, SPP's vice president for regulatory policy. But he and SPP President Nick Brown said this week that it will take longer and will cost considerably more to arrange for dynamic scheduling, especially because of the software modifications needed.

In March, the commission told SPP that participation by external generators in the real-time balancing market was key to addressing issues of market power and bid insufficiency. As proposed by the transmission organization, the responsibility and cost for designing, developing and operating a system of pseudo ties would have fallen on the external generators.

Placing the entire financial burden on external generators is unduly discriminatory and will unreasonably deter external generators from entering the market, FERC said (Docket No. ER06-451). The commission told SPP to come up with an alternative that would involve SPP and other market participants bearing a portion of the costs, "especially since we view a portion of these costs to be market startup costs to which all parties should contribute."

SPP started up its real-time balancing market February 1. When it proposed the pseudo ties for external generators, it requested an effective date of October 2 and added that it did not expect systems to be in place to permit involvement by external generators until March 1, 2008. It remains to be seen what new deadlines will be targeted.

"We direct SPP to determine whether a pseudo-tie mechanism or dynamic scheduling is the appropriate mechanism to facilitate entry by external generators," FERC said in its order. "SPP may find that dynamic scheduling is in fact a more cost-effective option, especially if large numbers of external generators are interested in participating in the market."

But dynamic scheduling definitely will cost more, Brown said. That was a factor in proposing pseudo ties, although he said the primary reason for offering pseudo ties was because that approach could be done quicker to meet FERC's mandate.

As for spreading some of the costs through the system, SPP will have to take that to its Regional State Committee, composed of representatives of the grid operator's state regulators. But a cost-allocation change most likely can be accomplished through the committee faster than the software changes can be made to accommodate dynamic scheduling, Dillahunty said.

FERC also told the RTO to gauge the extent of generator interest in participating. That assessment could be accomplished, for example, by SPP holding an open season, the commission said.

Cost allocation was not the only point of contention in SPP's proposal, but FERC declined to address the other objections. The commission said those issues may be rendered moot by the requirement for an alternative proposal.

Conectiv reaches settlement of nearly $700,000 with California, utilities over 2000-01 energy crisis

Conectiv Energy Supply, California's big three investor-owned utilities and California state officials last week submitted a settlement agreement to the Federal Energy Regulatory Commission, the latest in a very long string of such agreements stemming from the West Coast energy crisis of 2000-2001.

If FERC approves the deal, power supplier Conectiv would provide other settling parties $689,792 in one form or another, little of it likely to be a cash payment. About $627,000 of the settlement would be released from the California Power Exchange to an escrow account, after which an agreed allocation system eventually would distribute the money to the California parties. The California PX, defunct as an exchange since 2001, froze the accounts of many market participants. That has provided a pool of assets — unpaid receivables, in Conectiv's case — that can be used in settlements under the auspices of FERC.

The agreement provides that if FERC determines the payments should be higher or lower, Conectiv will pay the additional amount or receive the benefits of any decrease (Docket No. EL00-95). As with other FERC-jurisdictional settlements from the crisis, other parties that were involved in the California market at the time of the crisis can opt in to the Conectiv deal and request their share of the payments that will be released from escrow.

The deal covers transactions during the period January 1, 2000, through June 20, 2001. It is meant to settle claims of market manipulation, although the settling parties explicitly deny any wrongdoing.

LATE-BREAKING NEWS

Growing demand, limited additions are shrinking US margins, says Fitch

Growing demand and limited capacity additions are causing reserve margins to shrink across the US, said Fitch Ratings in its wholesale power market update report issued this week. These falling reserve margins along with rising heat rates all point to the need for new capacity, particularly in the Texas, Maryland and New York regions, said Fitch.

Heat rates are a broad measure of a generating unit's efficiency. The lower the heat rate the more efficiently the unit can convert natural gas into electricity. A typical combined cycle unit has a rating of about 7,000 Btu/kWh.

Regulated utilities are expected to meet the challenge of the next build cycle to meet the rising demand, according to Fitch, as opposed to the merchant players that took the lead in the last cycle. Further, natural gas-fired generation is seen to be the top choice for new generation units, with coal and nuclear following behind.

Market-clearing heat rates in the Northeast and Midwest regions will continue to rise in the next four years, according to the Fitch data. This, combined with declining reserve margins is likely to pump up cash flows and asset values for generators across the area, the rating agency said in a report.

In the PJM Interconnection, firmer capacity prices are expected in the New Jersey and Baltimore-Washington regions, where capacity values have increased since the implementation of the Reliability Pricing Model, the report points out. Overall, higher capacity prices indicate a need for additional generation units, but as of now only 100 MW of new generation is under construction in PJM, the data shows. Stronger power prices and transmission constraints are also likely to hit the PPL Electric Utilities area by 2010, according to the report.

Demand growth, supply shortage and transmission constraints will continue to push electricity prices in New York higher, according to Fitch. New York City and Long Island may experience scarcity of capacity by 2011, assuming a 2% load growth.

Gas-dependant New England is facing the similar problems associated with declining reserve margins and growing load, the report shows.

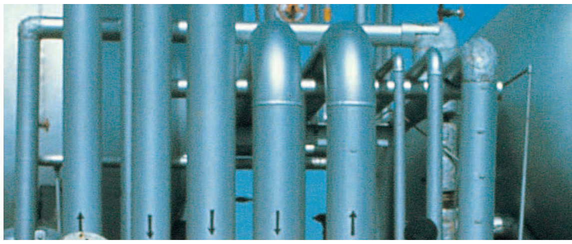
The Electric Reliability Council of Texas is predicted to see some of the highest market clearing heat rates in the future. For the ERCOT Houston zone, Fitch predicts a heat rate in 2008 of 8,424 MMBtu/kWh, rising to 9,030 MMBtu two year later, and then to 9,272 MMBtu/kWh for 2012.

The higher heat rates are expected to improve cash flows for most generators in the Texas markets, which could lead to improving credit fundamentals for issuers with generation in the region, particularly for coal and nuclear baseload.

Higher and volatile power prices are expected in the West, where the region largely relies on natural gas-fired, hydroelectric and renewable generation resources, despite projections for strong reserve margins in the future, said Fitch.

Fitch also said natural gas "remains the fossil fuel of choice in the West for incremental capacity" because of low emissions.

Fitch also revised its base case for Henry Hub natural gas prices to $8/MMBtu in 2008 and decline to $6/MMBtu by 2010, compared with the fall 2004 forecast which had an equilibrium price of $4.50/MMBtu range.



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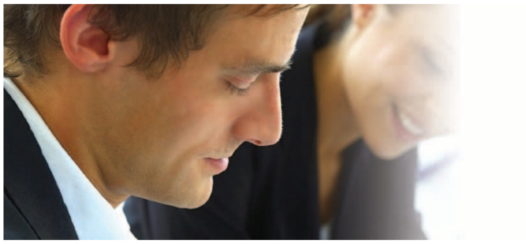

Thursday, November 15, 2007, Hotel Madero, Buenos Aires - Argentina

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