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Global Power Report

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Harbinger Capital, SPO file with FERC to take up to 45% stake in Calpine

Harbinger Capital Partners, long a thorn in the side of Calpine Corp., has done what market rumors have long suggested; it is making a bid to buy a large portion of Calpine's stock when that company exits bankruptcy.

In a November 16 filing with the Federal Energy Regulatory Commission, Harbinger Capital Partners Master Fund I Ltd., Harbinger Capital Partners Special Situations Fund LP, SPO Partners and San Francisco Partners II LP requested authorization under Section 203 of the Federal Power Act for Harbinger and SPO to own at least 10% of Calpine's stock upon its emergence from bankruptcy, expected by the end of January. In addition, the acquirers are seeking authorization to bring Harbinger's and SPO's ownership of Calpine stock up to 25% and 20%, respectively, once Calpine is out of bankruptcy.

Calpine has just released a re-evaluation of its enterprise value that pegs the value of its stock at about 41 cents/share (*see story, page six*).

Harbinger and SPO asked FERC to handle their request on an expedited basis, by January 10, 2008. Calpine could exit

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Despite green power boom, wave/tidal projects still lag solar and wind in commercial viability

On October 27, Finavera Renewables, the company that is perhaps the furthest along in developing wave power in the United States, sent a boat two and a half miles off the coast of Oregon to fish its electricity-producing buoy out of the water. The AquaBuoy had done well in its initial tests, but when they went to pull it on board, it sank.

On the East Coast, Verdant Power submerged six turbines in New York City's East River in an effort to tap the strong currents and turn them into electricity. The current snapped off the blades.

In Portugal, Enersis last month called a delay in a pilot project designed to demonstrate the potential of the Pelamis technology, a snake-like series of linked red cylinders that float on the ocean surface to tap into the energy of ocean waves.

For some who have observed the embryonic wave and tidal energy businesses, these problems are emblematic. Even in an era when other forms of "clean energy" have taken off, or are poised to do so, generating electricity from tides, currents and waves is proving to be a surprisingly difficult task.

Earlier this year, the Electric Power Research Institute reported that it could foresee 13,000 MW of power from wave and tidal installations in the US by 2025. In Europe, the Carbon

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Xcel, AEP and OG&E seek release from obligation to buy from qualifying facilities in SPP region

Three utilities are asking to be relieved of the obligation to buy power within the Southwest Power Pool from qualifying facilities under the Public Utility Regulatory Policies Act. Developers of renewable energy projects, now the dominant type of new QFs in the SPP region, are saying the regional transmission organization is not yet ready for that change.

The basic question is whether the RTO has evolved into a sufficiently competitive, liquid market where sellers of power from PURPA QFs can readily find alternative buyers for their output. Xcel Energy, American Electric Power and Oklahoma Gas and Electric on September 25 jointly made their case that SPP is indeed workably competitive.

"This is the first case in which the commission must evaluate the competitive opportunities available to QFs operating within a Day 1 market structure, thus raising a threshold issue," said Outland Renewable Energy in a filing opposing the change.

Opposition also was expressed by the Electric Power Supply Association, which said in a November 20 federal filing that EPSA disputed the applicants' claim "that competitive

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procurement opportunities are sufficiently robust throughout SPP." Other companies and trade groups were set to file remarks November 21.

The three utilities staked their case especially on a comparison with the Electric Reliability Council of Texas. The Federal Energy Regulatory Commission has determined that although ERCOT, like SPP, does not operate a day-ahead market, its markets are of a similar competitive quality to the "Day 2" RTOs that do run day-ahead markets. If FERC were to agree that SPP is sufficiently similar to the Texas grid operator, it could conclude that there is no longer a need for obligatory purchases in SPP under the PURPA mandate.

But SPP, with relatively low volumes of power trading and a less-developed grid, is not there yet, according to critics.

"The reaction I've been getting from some of our members is, it's nothing like ERCOT," said Robert Gramlich, policy director of the American Wind Energy Association. "ERCOT's a fantastic market."

Gramlich said SPP "has taken great strides," and he added, "Ultimately, we'd love to see SPP develop those market processes better." His friendly tone toward SPP may prove typical of the responses.

"In many respects this is going to be a very good market," said David Schwartz, a Latham & Watkins attorney representing wind power developer Noble Environmental Power. But Schwartz suggested that SPP has some basic steps to take before the PURPA obligations can end there.

SPP needs more liquidity, which the RTO can develop by such means as expanding transmission to overcome constraints, creating financial transmission rights to deal with congestion, and improving its rules to make it easier for generators to sell their output beyond their interconnecting utility, Schwartz said. SPP also could create a day-ahead market and has talked of wanting to do so, but it remains to be seen whether that will happen, he said.

EPSA similarly cited the need for better rules. SPP is still trying to set up a system for allowing generators outside of the SPP footprint to sell into the RTO's real-time balancing market. The rules for those sales "are a significant component of a fully competitive RTO market," the trade group said.

"Additionally, SPP has only recently submitted tariff revisions to its Large Generator Interconnection Agreement," EPSA said. "Clear and settled interconnection procedures are a fundamental element of an organized market, and directly impact the ability of competitive generators to access transmission service in order to reach customers. ... This lack of regulatory certainty regarding such a fundamental market element represents a barrier to entry for competitive suppliers."

EPSA also stressed that competitive procurement is not as developed within SPP as it should be. Arkansas, Kansas and New Mexico have no state requirements or standard for competitive procurement, the group said. As a result, there is no independent monitoring or administering of power procurement in those areas. EPSA also cited cases in Oklahoma and Colorado that called into question how genuine was the effort at competitive procurement by AEP, OG&E and Xcel.

The Energy Policy Act of 2005 permitted escape from the PURPA requirements only where there is workable competition and only going forward. Existing contracts cannot be abrogated. Generation companies do not appear to be averse to the idea, as long as the conditions for competition are genuinely there.

"The days for relying on PURPA should be ending," Schwartz said.

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Harbinger and SPO file with FERC to take up to 45% stake in Calpine... from page 1

bankruptcy as early as mid-December, but hopes to have its reorganization plan approved by its creditors by no later than the end of January. Calpine is also an applicant in the filing because, without FERC authorization, Calpine would not be able to transfer its shares and exit bankruptcy.

In their filing, Harbinger and SPO say they would not, in fact, trigger Section 203 review because the transaction would not result in a transfer of control. Harbinger and SPO also claim status under FERC rules that grant blanket authorization to unregulated power companies (exempt wholesale generators, or qualifying facilities under the Public Utility Regulatory Policies Act, for instance) to acquire stakes of up to 10% in a power company.

Harbinger Capital Partners Master Fund owns a two-thirds interest in Kelson Holdings LLC. Harbinger Special Situations owns one-third of Kelson, which owns nearly 4,000 MW of gas-fired generation — all named after flowering trees — in Texas, Missouri, Mississippi and Oklahoma.

Harbinger and SPO, as Calpine debtholders, expect to be paid in part in Calpine stock under the company's reorganization plan. The exact amount of the distributions will not be known until Calpine actually effects its reorganization plan. It was not clear at press time how much debt or what classes of debt Harbinger or SPO hold.

Harbinger was a buyer of Calpine's debt a year before the merchant firm declared bankruptcy. And in the spring of 2005 a dispute broke out between Calpine and Harbinger over control of the proceeds from Calpine's sale of the 1,200-MW Saltend plant in the United Kingdom. Harbinger said Calpine was misusing the proceeds to the detriment of the entities that had invested in the debt instruments for Saltend (*GPR*, 5 May '05, 1). That dispute proved to be the beginning of the end for Calpine.

In February, a Canadian subsidiary of Calpine Corp. sold Calpine Power Income Fund to HCP Acquisition, a subsidiary of Harbinger Capital.

In May, Harbinger, as one of Calpine's largest convertible noteholders, reportedly met with other convertible debt and common shareholder to discuss a potential capital infusion in Calpine (*GPR*, 7 June, 1). The results of that meeting have never been revealed.

Despite green power boom, wave/tidal power still lag behind wind, solar energy ... from page 1

Trust, a private group based in London, argued in a 2006 report on marine energy that several gigawatts each of wave and tidal energy could be installed by 2020.

To date, however, there are only three commercial hydrokinetic projects in operation, one of 400 kW in Russia, the 240-MW Rance tidal station in St. Malo, France, and a 20-MW tidal project installed in the Bay of Fundy by Nova Scotia Power in 1984. But in the two-plus decades since Nova Scotia Power's Annapolis Royal project went online, there has not been a single new commercial hydrokinetic project and only a handful of pilot projects.

Marine Current Technologies has had a 300-kW pilot project off the coast of Devon, England, since 2005. Oceanlinx installed a 500-kW project at Port Kembla, Australia, in the summer of 2007. Verdant has its 210-kW Roosevelt Island Tidal Energy project in the East River. And there is the 500-kW shore-based LIMPET wave station on the Hebridean Island of Islay, Scotland.

"There have been a lot of ideas looking for money, a few ideas funded, but no one has come up with a commercial idea yet," said Edwin Feo, co-chair of Milbank, Tweed, Hadley & McCloy's global power, energy and utilities group.

Today in the tidal and wave world there are "guys building custom machines, trying to make them work," said Feo. He noted that the machines are mechanical energy converters, not chemical or biological in nature. "Its not like the technology is way off in the future, like hydrogen," he said, "and the costs are not that bad. We are not at a point of trying to figure how to get these machines to convert energy, but rather how to get

Wave power needs a tide of technology

The specific challenges of harnessing the energy of waves and tides have prompted distinctly different types of devices. The European Marine Energy Center, for instance, identifies several types of devices designed to convert wave energy into electricity. An attenuator is a snake-like series of linked cylinders like those manufactured by Pelamis. It sits on the ocean surface and converts the rocking motion of the waves into electricity. A point absorber looks like a buoy. It bobs up and down and uses that motion to convert kinetic energy into electricity. AquaEnergy, now Finanvera, is using this technology.

An Oscillating wave surge converter looks like a large, flat piece of seaweed sitting on the sea bed floor. As waves push it back and forth, it converts that motion to electricity. An oscillating water column, used by Australian company Oceanlinx, is partially submerged and hollow like a glass held upside down in the water. The trapped air in the upper part of the device is compressed by the rising and falling of the water level. The compressed air turns a turbine/generator. And finally an overtopping device traps water from waves and funnels it through a turbine before releasing it back to the sea.

Devices to harness tidal power resemble traditional turbines used in wind farms or gas plants. Like traditional hydropower plants the turbines can be mounted on a vertical or horizontal axis. Verdant Power is using a horizontal axis turbine in a pilot project in New York's East River. These devices are often housed in ducts, which create secondary flow effects to produce a pressure differential. When housed in a funnel-like device like a Venturi, the turbines can be turned by mass or pressure, or both.

Another type of tidal device is an oscillating hydrofoil. It somewhat resembles a see-saw. On end a hydrofoil rises and falls with the passing waves forcing a plunger on the other end to drive a hydraulic system to produce electricity.

There are several other designs and no clear winner. But most of the designs are variations on these main concepts.

Hydrokinetic permits issued by FERC

Company	Project	Location	State	Type
Chevron Technology Ventures LLC	Cook Inlet	Kenai Peninsula	Alaska	tidal
Natural Currents Energy Services LLC	Angoon	Kootznahoo Inlet	Alaska	tidal
Ocean Renewable Power Co.	Resurrection Bay	Resurrection Bay	Alaska	tidal
Ocean Renewable Power Co.	Cook Inlet	Cook Inlet	Alaska	tidal
Oceana Energy Co.	Central Cook Inlet	Cook Inlet	Alaska	tidal
Oceana Energy Co.	Kackemak Bay	Cook Inlet	Alaska	tidal
Oceana Energy Co.	Icy Passage	Icy Passage/Strait	Alaska	tidal
Oceana Energy Co.	Gastineau Channel	Gastineau Channel	Alaska	tidal
Oceana Energy Co.	Wrangell Narrows	Wrangell Narrows	Alaska	tidal
Oceana Energy	San Francisco Bay	San Francisco Bay	Calif.	tidal
Natural Currents Energy Services	Housatonic Tidal Energy Plant	Housatonic River,	Conn.	tidal
Florida Hydro	Gulf Stream Energy	Atlantic Ocean	Florida	current
Ocean Renewable Power Co.	SeaGen Tranvernier	Atlantic Ocean	Florida	current
Ocean Renewable Power Co.	SeaGen Key Largo	Atlantic Ocean	Florida	current
Ocean Renewable Power Co.	SeaGen St. Sebastian	Atlantic Ocean	Florida	current
Ocean Renewable Power Co.	SeaGen W. Palm Beach	Atlantic Ocean	Florida	current
Ocean Renewable Power Co.	SeaGen St. Lucie	Atlantic Ocean	Florida	current
Ocean Renewable Power Co.	SeaGen Ft. Lauderdale	Atlantic Ocean	Florida	current
Ocean Renewable Power Co.	SeaGen Miami	Atlantic Ocean	Florida	current
Maine Maritime Academy	Tidal Energy Device Evaluation Center	Bagaduce Narrows	Maine	tidal
Ocean Renewable Power Co.	Cobscook Bay	Cobscook	Maine	tidal
Ocean Renewable Power Co.	Western Passage	St. Croix River	Maine	tidal
Oceana Energy Co.	Penobscot	Penobscot River	Maine	tidal
Passamaquoddy Tribe	Passamaquoddy Tribe	Cobscook	Maine	tidal
Tidewalker Associates	Half Moon Cove	Cobscook	Maine	tidal
Natural Currents Energy Services LLC	Cape Cod Tidal Energy Plant	Cape Cod Bay	Mass.	tidal
Oceana Energy Co.	Cape and Islands	Vineyard Sound	Mass.	tidal
Oceana Energy Co.	Portsmouth	Piscataqua River	New Hampsire/Maine	tidal
UEK Corp.	Piscataqua	Piscataqua River	New Hampsire/Maine	tidal
Natural Currents Energy Services LLC	Long Island Sound	Long Island Sound	New York	tidal
Natural Currents Energy Services LLC	Wards Island	East River	New York	tidal
Oceana Energy Co.	Astoria	East River	New York	tidal
Verdant Power	Fishers Island	The Race	New York	tidal
Verdant Power	Orient Point	Plum Gut	New York	tidal
Verdant Power	Roosevelt Island	East River	New York	tidal
Douglas County	Douglas County	Pacific Ocean	Oregon	wave
Finavera	Coos County Wave Project	Pacific Ocean	Oregon	wave
Ocean Power Technologies Inc.	Reedsport OPT Wave Park	Pacific Ocean	Oregon	wave
Oceana Energy Co.	Columbia	Columbia River	Oregon	tidal
Oregon Wave Energy Partners I LLC	Coos Bay	Pacific Ocean	Oregon	wave
Natural Currents Energy Services LLC	Willipa Bay	Willapa Bay	Wash.	tidal
PUD No. 1 of Snohomish County	Admiralty Inlet	Puget Sound	Wash.	tidal
PUD No. 1 of Snohomish County	Deception Pass	Puget Sound	Wash.	tidal
PUD No. 1 of Snohomish County	Agate Passage	Puget Sound	Wash.	tidal
PUD No. 1 of Snohomish County	Spieden Channel	Puget Sound	Wash.	tidal
PUD No. 1 of Snohomish County	Guemes Channel	Puget Sound	Wash.	tidal
PUD No. 1 of Snohomish County	San Juan Channel	Puget Sound	Wash.	tidal
PUD No. 1 of Snohomish County	Rich Passage	Puget Sound	Wash.	tidal
Tacoma Power	Tacoma Narrows	Puget Sound	Wash.	tidal

Source:Federal Energy Regulatory Commission

them to survive the elements they have to perform in." There are different companies with different approaches, "but everyone is looking for what will work, what won't get destroyed out in the water."

Although he acknowledges that setting a cost/kWh for wave or tidal power is like estimating the costs of "building a car in your garage," Feo said that at about 25 cents/kWh wave and tidal power is considerably more expensive than solar, which is in the 14 cents/kWh to 16 cents/kWh range, and far from more expensive than conventional renewable resources like biomass (6 to 9 cents/kWh), geothermal (5 to 6 cents/kWh), and wind (5 cents/kWh).

Alla Weinstein, who was instrumental in developing the AquaBuoy, does not disagree with FEO's estimates, but believes it is premature to discuss costs.

One of the factors keeping prices high, she said, is the lack of economies of scale in the manufacture of equipment to capture and convert tidal and wave energy. Right now, project developers are also serving as equipment suppliers and vice versa.

To better understand the cost of hydrokinetic power, Weinstein says it is useful to look at the break-down of capital costs for wave and tidal projects. She cited a Carbon Trust analysis that broke down the capital costs for a wave project as follows: 49% for mechanical and electrical parts, 27% for the structure, 13% for installation, 5% for mooring, 4% for grid connection, and 2% for project management.

For tidal projects that use a submerged turbine and generator, Carbon Trust put the cost of the mechanical and electrical components at 39%, the structure at 39%, 13% for the grid connection, 7% for project management, and only 2% for installation.

"There will be a huge drop in price with installed capacity, but until there is installed capacity, there are just projections of costs," said Weinstein.

Meanwhile, there are costs to bear just to test the equipment. Verdant Power has spent $9 million so far on its East River project, $3 million from the New York State Energy Research and Development Authority and $6 million from family and friends, according to Trey Taylor, the Arlington, Virginia, company's president and head of market development.

In addition, billionaire commodity trader Paul Tudor Jones has invested an additional $7 million in Verdant to move it along on the "path to commercialization," said Taylor.

Taylor noted that $2 million of the $9 million cost of the East River project has been for equipment to monitor the project's impact on fish and diving birds. Based on his experience of actually installing a working hydrokinetic project, Taylor now puts Verdant's installed cost at $2,400/kW with an operation and maintenance cost of 7 to 9 cents/kWh.

Weinstein, whose AquaEnergy was bought by Finavera in 2006, also says there is a role for the government in fostering wave and tidal power.

Wave power does not need a production tax credit, like that given for wind power, she said, but it does need an investment credit for research and development. She noted that Representative Jay Inslee, a Democrat from Washington, has proposed an ocean energy bill that includes investor tax credits.

She also pointed out that Oregon provides an investment credit for wave power, which is why Finavera established its US headquarters in Portland.

In fact, wave and tidal power is so undeveloped that the regulatory process is still being hammered out, and is sometimes subject to jurisdictional overlap and even confusion.

It was not until October 2003 that the Federal Energy Regulatory Commission devised its preliminary permitting process for hydrokinetic projects.

FERC claims its power to license wave and tidal projects under its long-held authority over hydroelectric power projects. But the preliminary permits do not allow a company to install a hydrokinetic project and sell power from it. What it does, in fact, do is give an entity the right to conduct a feasibility study.

Between February 2005 and October 2007, FERC has granted a total of 49 preliminary permits, and has 11 more projects awaiting permits (*see tables, pages four and five*). In all, they represent as much as 5,200 MW of hydrokinetic capacity. A total of 45 of the issued permits are for the study of tidal and current power projects; four are for wave projects. Among the 11 pending permits, however, eight are for wave projects and three are for tidal projects. The permits, both pending and issued, are almost evenly split between the West and East coasts.

Experts say that the Bay of Fundy, between New Brunswick and Nova Scotia, and the Cook Inlet in Alaska are the mother lodes of tidal power in the US, which is why 17 of the projects are in Alaska or Maine.

The furthest-out projects on the list are those for permits to study sites in the Gulf Stream off the coast of Florida. Ocean Renewable Power Co. has seven Gulf Stream permits that it inherited from its take over of Red Circle Energy in March 2006.

Founded by Paul Wells, a former cruise ship captain, Red Circle's plan was to go as far as 25 miles off shore to tap the Gulf Stream current. That drew FERC's first permits in February 2005. Recently, Wells, now chairman of Ocean

Hydrokinetic permits pending at FERC

Company	Project name	Location	State	Type
AquaEnergy Group, Ltd.	Humboldt County Wave Project	Pacific Ocean	Calif.	wave
Chevron California Renewable Energy, Inc	Mendocino Wave Energy Project	Pacific Ocean	Calif.	wave
Ocean Power Technologies	Fairhaven OPT Wave Power Project	Pacific Ocean	Calif.	wave
Pacific Gas and Electric	Humboldt WaveConnect Project	Pacific Ocean	Calif.	wave
Pacific Gas and Electric	Mendocino WaveConnect Project	Pacific Ocean	Calif.	wave
Oceana Energy Corp.	Kennebec	Kennebec River	Maine	tidal
Tidewater Assoc.	Cutler	Little Machias Bay	Maine	tidal
Natural Currents Energy Services LLC	Nantucket Tidal Energy Plant	Nantucket Sound	Mass.	tidal
Lincoln County, Oregon	Lincoln County Wave Energy	Pacific Ocean	Oregon	wave
Ocean Power Technologies	Newport OPT Wave Park	Pacific Ocean	Oregon	wave
Oceanlinx	Florence Wave Park Project	Lane County	Oregon	wave

Source: Federal Energy Regulatory Commission

Renewable Power, said there was uncertainty as to whether FERC would continue to have authority over developments on the Outer Continental Shelf, or whether the Minerals Management Service of the Department of the Interior would assume an exclusive role.

In an effort to shed greater clarity on the process, Secretary of the Interior Dirk Kempthorne on November 5 announced an interim policy designed to collect data and examine the impact of alternative energy facilities (the Final Programmatic Environmental Impact Statement for the Outer Continental Shelf Alternative Energy and Alternate Use Program).

FERC, meanwhile, is taking steps to harmonize its waterway guardianship under the Federal Power Act and its new role as a foster parent for emerging alternative energy technologies under the Energy Policy Act of 2005.

Wary of granting hydroelectric style multi-decade license for a technology with no track record, FERC is taking steps toward devising a permitting process that reconciles it roles. The commission is seeking comments on a proposed program that would allow applicants with projects that are of 5 MW or less to obtain a five-year license after just a six-month application process. The applicant would be able to generate power while in the testing phase, but would also have to prove that the device could be pulled from the water if there were any untoward effects. At the end of the five-year license term, the owner would have the option of applying for a 30- to 50-year license.

The pressure on FERC to give more leeway to new technologies is shown in the fact that the commission has already granted an exception to the prohibition against generating power under its preliminary permit.

Verdant generates power from its East River project, but does not sell it. In what Taylor, the company's president, says is now called the "Verdant Ruling" gives away the power it produces. It is used to light a grocery store and a parking garage on Roosevelt Island in the middle of the East River.

Taylor says Verdant will eventually have 30 turbines in the East River, which would give the company 1 MW of saleable power. He pointed out that Verdant also has the channel on the other side of Roosevelt Island, between the island and the United Nations, under permit. He said that if both "fields" are developed, Verdant could eventually have 10 MW of capacity from the two sites.

In addition, Taylor said, Verdant has FERC permits for two sites in the Long Island Sound, and is planning a project in the St. Lawrence River near Cornwall, Ontario, that would be phased in over four years beginning in the fall of 2007 and would eventually reach 15 MW.

Taylor noted that, because of the tidal nature of the East River the company's project operates at a 30% capacity factor. The St. Lawrence project, however, could have a 90% capacity factor, he said.

But the next big hurdle is to move into commercial production. Taylor says Verdant already has a deal giving KeySpan the right-of-first-refusal on the commercial power Verdant eventually hopes to generate. "A lot of people have been clamoring for the power," Taylor said. There is no problem selling power in New York City, he added. — *Jeffrey Ryser*

COMPANY NEWS

Calpine, attempting to please all stakeholders, comes up with a new, $900 mil lower valuation

Calpine, eager to appease its creditors so that they will approve its reorganization plan by the end of January, has finished a re-evaluation that puts the company's enterprise value $900 million lower than it was five months ago.

The revaluation will affect general unsecured creditors to some degree, but is likely to have a much more dramatic impact on holders of the company's stock. Based on the revaluation, shareholders may receive nothing or receive stock worth only $0.41/share.

Prior evaluations pegged Calpine's stock as high as $2.05/share.

In its statement, Calpine was quick to say that the final determination of what creditors would receive remains up to the bankruptcy court.

Calpine promised creditors it would perform the valuation in late September, when the US Bankruptcy Court for the Southern District of New York ruled that Calpine's reorganization plan was "confirmable."

The new valuation will provide the basis for a vote on the plan by creditors by November 30. If creditors vote their approval next week, there would be a final confirmation hearing on December 17.

Calpine has repeatedly said it wants to be out of bankruptcy by the end of January so it can take advantage of a favorable $8 billion financing package offered by four banks.

Calpine's financial consultant, Miller Buckfire & Co., was forced to make the new valuations of the company's enterprise value because the equity committee had complained that values submitted in its original plan of reorganization filed June 20, needed to be updated as a result of severe market volatility over the past several months (*GPR*, 4 Oct, 1).

Originally, Calpine estimated its future enterprise value at $20.3 billion and, based on estimated number of claims, the company argued that general unsecured creditors would receive between 91% and 100% of their allowed claims, while equity holders would receive value of approximately $1.80 per existing share.

On August 27, using the same enterprise value, but reducing the estimates of the amount of claims it would pay out, Calpine said that general unsecured creditors would receive between 95% to 100% of their allowed claims, while equity holders would receive approximately $2.05 per existing share.

Miller Buckfire's new estimate now puts the mid-point of Calpine's total enterprise value at $19.35 billion.

Calpine said that using that mid-point and a "litigation-risk assessment of allowed claims" general unsecured creditors will recover 96.7% of their allowed principal plus pre- and post-petition interest claims, while shareholders would receive no recovery.

Using, however, a "low-claims" estimate, unsecured creditors would be paid their allowed principal plus pre- and post-petition interest claims in full, and shareholders would receive $0.41.

Calpine then said that using a “high-claims” estimate, unsecured creditors would recover 88% of their allowed principal plus pre- and post-petition interest claims, or the equivalent to 99.7% of allowed principal plus pre-petition interest claims, while shareholders would again receive nothing.

Calpine’s stock closed 2006 in the 90 cents/share range, but soared to a 52-week high of $4.15 in May. Calpine’s shares have since fallen, in step with declines in the broader market. Trading on the pink sheets, Calpine’s stock closed at 49 cents/share.

To arrive at the enterprise value Calpine said Miller Buckfire reviewed certain operating and financial forecasts prepared by Calpine’s management, including an updated projection of cash earnings before interest, taxes, depreciation, amortization, operating rent, and restructuring charges, cash EBITDAR, as of November 1, 2007, for the period January 1, 2008 through December 31, 2013.

The company noted that its cash EBITDAR projections were based on the “forecasted consolidated financial results of Calpine and its non-debtor affiliates,” and took into account: forward curves for power and gas as of June 29, 2007, updated plant operating characteristics, contracts entered into at certain of Calpine’s facilities since Calpine’s April 2007 business plan, long-term gas price projections, market data, including regional supply and demand and the construction costs of power facilities in the markets in which Calpine operates, certain developments with carbon regulations that are projected to impact Calpine’s operations, and decreased corporate overhead and selling, general, and administrative expense estimates.

Calpine said the $900 million decrease in the midpoint estimate from June was the result of a “general decrease” in the market enterprise value of “selected companies” it uses in its valuation analysis, and a general increase in market volatility, “both partially offset by the increases in Calpine’s updated cash EBITDAR projections.”

Dynegy’s Williamson sees difficult market in which to build, but opportunities to buy

It is a difficult market in which to build power plants, but there are opportunities to build a balanced portfolio and bulk up in a consolidating industry, said Dynegy CEO Bruce Williamson at a conference in New York City last week.

“Not only are people reluctant to build right now, it is a darn sight more difficult,” said Williamson at the DLA Piper Energy Marketplace meeting.

Williamson cited rising construction and fuel costs, but mostly uncertainly about government environmental policies. There is no quick or easy solution to that uncertainty, he said. It could be 2010 at the earliest before federal environmental legislation, which is now moving through Congress, is actually passed into law, he said. “We are not going to figure it out in the next 24 months. It is a transition, and it is going to be costly.”

Dynegy is building plants however, particularly through its joint venture with LS Power, which developed the 665-MW Plum Point project in Arkansas, one of the few independent coal-fired plants to be funded in recent years.

Sounding a theme that he has repeated before, Williamson said that the “power industry is fractured” and is filled with “little players like us” with an $8 billion market capitalization.

Dynegy is looking opportunistically at M&A opportunities, said Williamson. In addition to the company’s merger/joint venture with LS Power, he cited the company’s recent sale of its 534-MW CoGen Lyondell plant in Channelview, Texas, to EnergyCo, a joint venture of PNM Resources and a subsidiary of Cascade Investment, the investment vehicle formed by Bill Gates, head of MicroSoft, for $470 million. In that deal, Dynegy got “120% of replacement value” for a 22 year old plant, said Williamson.

Williamson also mentioned that the Federal Energy last week to sell its 310-MW gas-fired Calcasieu peaking plant to Entergy Gulf States for $57 million.

“The power industry needs to grow up,” said Williamson. Right now most power companies are too small to prudently build a large power project on their balance sheet. But a company with a $100 billion of equity capitalization would be able to build out the capacity that is required. Williamson particularly questioned the prudence and likelihood of power companies, especially merchant companies, building nuclear power plants. It is like a $150 billion oil company announcing a $30 billion project. Wall Street just would not accept it, he said.

Dynegy is also working on building a “balanced hedging strategy,” said Williamson. “We are trying to strike a balance” between predictability and capturing upside for shareholders.

Williamson said Dynegy views its peaking plants as “financial options.” “We don’t put a hedge on peakers at all, except for what we sell into the capacity auctions,” he said.

Dynegy sells the output from its baseload plants forward under contracts that cover the current year plus one year, and its sells the output of its intermediate plants forward under contract for the current year plus four years.

About 42% of Dynegy’s power plant portfolio is comprised of peaking plants. About 26% of the company’s portfolio is intermediate plants, and the remaining 32% of the portfolio is baseload plants.

Responding to a question about whether or not liquefied natural gas would make much a difference for gas supplies in North America, Williamson said, “I’m a real bear on LNG.”

Referring to his past experience at a major oil company, he said “we used to call it price majeure. Once a cargo [of LNG] is on the water, it is going to go to the highest market,” he said. “We could have a lot of LNG in the US,” said Williamson, “if the price is high enough.”

Southern separates functions of merchant and regulated units under orders from FERC

Southern Company has told the US Federal Energy Regulatory Commission that it has finished separating the functions of its merchant power unit from those of its regulated utility units, as FERC ordered in October 2006.

In the culmination of an extraordinarily contentious case, FERC told Southern to live under rules by which other utilities with merchant affiliates must abide, so that the merchant unit does not have an advantage in bidding for power supply contracts and in other business.

As a result, Southern made changes that it said included relocating departments, installing numerous key-card-locked doors and putting controls on electronic access that employees of Southern Power, the merchant unit, would otherwise have to prohibited market information. These measures "have consumed a significant amount of time and expense," Southern said.

The company's filing said FERC's Office of Enforcement likely will start auditing the implementation effort starting November 19.

The market information that will be blocked from Southern Power staff encompasses non-public information related to sales, cost of production, generator outages, generator heat rates, unconsummated transactions and historical generator volumes.

The company said Southern Power may use shared services, but pay direct and indirect costs for them. The other Southern companies will sell non-power goods and services to Southern Power at prices that are the higher of cost or market, and the other companies will not buy non-power goods and services from Southern Power for more than market value.

Energy East shareholders OK merger with Spanish energy company Iberdrola

The shareholders of Portland, Maine-based energy services and delivery company Energy East on November 20 overwhelmingly approved its merger with Spain's Iberdrola. About 93% of the votes received were in favor of the merger, Energy East said.

Under the deal, Energy East, which serves about 3 million customers in upstate New York and New England, will become a wholly owned Iberdrola subsidiary.

Energy East shareholders will be entitled to $28.50 in cash in exchange for each share of company common stock they own upon completion of the merger. The merger remains subject to various state and US regulatory approvals and other customary closing conditions. Energy East expects the merger to be completed in the first half of 2008.

Invenergy contracts with General Electric for 800 MW of wind turbines for 2009 delivery

Invenergy Wind LLC of Toronto has contracted with General Electric to deliver 800 MW of wind turbines to Invenergy in 2009 to support the company's North American and European wind farm development program.

Invenergy noted that it previously had contracted with GE to provide 600 MW of wind turbines for delivery in 2007 and 700 MW in 2008.

"Invenergy Wind currently has 13 wind energy facilities representing more than 1,200 MW of projects in operation or under construction in North America and Europe," the company said. Invenergy Wind is a subsidiary of Invenergy LLC.

FINANCE

TXU, now Energy Future Holdings, reports drop in income for third quarter to $992 mil

Energy Future Holdings last week reported third-quarter income of $992 million, down 1.2% from the third-quarter record of $1.004 billion a year before.

EFH's revenue slid 1.8% to $3.44 billion. Basic earnings per share fell 1.8% to $2.15 and diluted 0.9% to $2.13, on 460 million average basic shares, up 1 million, and 465 million diluted, down 1 million.

Income for the former TXU's competitive electric segment improved $46 million in the most recent quarter, compared with the 2006 same quarter, and income dipped $7 million in the regulated delivery segment, or utility Oncor Electric Delivery.

Most of the $12 million drop in overall income from last year resulted from a $44 million surge in the loss in the "corporate and other" segment, which includes discontinued operations, general corporate expenses, and interest on parent corporation debt.

Energy Future Holdings reported results in a Form 10-Q filed with the Securities and Exchange Commission no November 14. They do not reflect the October 10 acquisition by private equity investors, after which the common stock is no longer publicly traded.

The company's competitive segment benefited from lower energy costs and a surge in unrealized mark-to-market gains, which more than offset lower power sales as cooler weather cut consumption and customers moved to other suppliers. Quarterly income for the segment improved 5.1% to $946 million.

Revenue for the segment, formerly TXU Energy, now called Texas Competitive Electric Holdings, fell 3.6% to $3.03 billion, reflecting price discounts to residential customers. The $360 million slump in retail revenue was almost offset by a $344 million surge in "net gains from risk management and trading," mainly unrealized mark-to-market gains on derivatives, due to a decrease in forward natural gas prices.

The competitive segment supplied 61% of customers in TXU's historical service territory, down from 67% in third quarter of 2006. Retail power supply revenue was down 15.7%, to $1.92 billion, as sales dropped 9.7% to 15,004 GWh.

With cooler weather, sales to customers in TXU's territory dropped 16.4%, to 9,407 GWh, led by a 16.9% slide in the residential sector, to 7,341 GWh. The company reported 1.55 million customers as of September 30, down 7.1% from the same period last year.

Total revenue for Energy Future Holdings slid 1.8% in the third quarter, to $3.44 billion. Results included $18 million of pre-tax acquisition-related costs.

Wholesale revenue slid 13.4% from 2006, to $589 million, as sales went down 2.2% to 9,938 GWh.

Expenses dropped 9.3%, to $1.59 billion, led by a 12.2% slide in fuel, purchased power and delivery fees, to $1.18 billion. Interest and related charges climbed 19.3%, to $130 million, but that was mostly offset by a 59% surge in interest income, to $97 million. Income taxes rose 10.7%, to $486 million.

Income for the regulated delivery segment fell 5.3%, to $124 million, on operating revenue of $712 million, up 0.6%. Deliveries slipped 4.7%, to 31,558 GWh.

Expenses rose 2.1%, to $446 million, led by a $20 million hike in operating costs, partially offset by a $9 million drop in depreciation and amortization. Interest and related costs were up 8.3%, to $65 million. Income taxes fell $1 million, to $70 million.

Endesa sees 3.7% drop in third-quarter profit to $1.070 billion on poorer results in Europe

Gains in Latin America helped Endesa partially offset losses in Spain and the rest of Europe, with the Spanish generator registering a net profit drop of 3.7% year-on-year to Eur724 million ($1.070 billion) for third-quarter 2007.

The poorer results for Spain and Europe, the company said November 15, are largely because of non-recurring items boosting earnings the previous year. For continuing operations, net profit rose 13%, Endesa added.

Meanwhile, EBIT rose 6.9% to Eur1.323 billion for the three-month period, EBITDA by 3.7% to Eur1.781 billion and revenues by 10.8% to Eur5.669 billion. Net financial debt at September 30 totaled Eur21.183 billion, up 6.8% from the start of the year.

Besides the impact of nonrecurring items, factors affecting the results include lower Spanish pool prices, modest demand growth in Spain, decreased demand in the rest of Europe coupled with reduced power production, lower fuel costs, fiscal changes in Italy and higher electricity sales in Latin America.

By key business division, third-quarter net profits were Spain and Portugal, down 4.6% to Eur517 million; the rest of Europe, down 22.1% to Eur81 million; and Latin America, up 18.9% to Eur126 million.

For the first nine months of the year, Endesa's net profit fell 21.1% to Eur1.979 billion, while EBIT climbed 5.6% to Eur4.100 billion and EBITDA by 6.9% to Eur5.612 billion.

Endesa added that overall power production for the first nine months of 2007 fell 2.6% to 137,431 GWh, while electricity sales rose by 2.8% to 168,865 GWh.

By region, generation output rose 1.5% to 69,246 GWh in Spain and Portugal but decreased 9.7% to 23,888 GWh in the rest of Europe and 4.5% to 44,297 GWh in Latin America, but with especially strong growth in Peru.

Electricity sales by region were: Spain and Portugal, up 3.6% to 85,177 GWh; the rest of Europe, down 3% to 37,745 GWh; and Latin America, up 6.4% to 45,943 GWh, pushed up by significant gains in Peru, Argentina and Brazil.

ASIA/PACIFIC RIM

Thirteen bidders express an interest in bidding for fourth ultra-mega coal-fired power project

Thirteen investor groups have expressed interest in bidding for the 4,000-MW Tilaiya ultra-mega project in the eastern Indian state of Jharkhand.

An official associated with the bidding process said the groups that submitted the request for qualification are Reliance Power Ltd., Tata Power Co., NTPC Ltd., Sterlite Ltd., Essar Power Ltd., AES Corp., GVK Power Ltd., Citra Power and Infrastructure Ltd., Lanco Infratech Ltd., Jindal Steel Ltd., Dian Wijaya Bhd., Larsen & Toubro Ltd. and Torrent Power Ltd.

State-owned Power Finance Corp., which is bidding out the project on behalf of the Indian government, would announce the list of the companies qualified to bid for the projects in two weeks. The final bids for the project have to be submitted by mid-March.

Local coal is the fuel for the Tilaiya project. The Tilaiya project was to have been originally awarded by May, but the delay in the award of the other ultra-mega projects led to the postponement of Tilaiya's auction schedule.

The power produced from Tilaiya would be sold in the states of Delhi, Punjab, Haryana, Madhya Pradesh, Jharkhand and Bihar.

The government is bidding out a total of nine ultra-mega projects to the private sector. So far, Power Finance Corp. has awarded three ultra-mega projects: Sasan, Mundra and Krishnapatnam. Reliance Power won the Sasan and Krishnapatnam projects. Tata Power won the Mundra project.

Aboitiz, Philippine bank sign separate pacts with Taiwanese firms for 710 MW of projects

Aboitiz Power Corp. and Metropolitan Bank & Trust have signed separate agreements with Taiwan Cogeneration Corp. and Formosa Heavy Industries Ltd. to set up power projects totaling 710 MW in the Philippines.

An Aboitiz spokesman said the joint venture with state-owned Taiwan Cogeneration, Redondo Peninsula Energy Inc., would develop a $420 million, 300-MW coal-fired plant at Subic Bay. Aboitiz did not provide details on the shareholding split of the joint venture. The plant is expected to start commercial operation in 2011, and its capacity is likely to be increased to 600 MW after that.

Separately, Global Business Power Corp., the power unit of Metropolitan Bank, the Philippines' largest bank, signed an agreement with Formosa Heavy Industries to build two coal-fired projects in the central Philippines at a cost of $500 million. Plans call for a 246-MW plant in Toledo City and a 164-MW plant in Iloilo City. The bank did not provide further details on the agreement.

Formosa Heavy Industries, owned by the Formosa group of companies, owns and operates 14,000 MW of coal-fired plants mainly in Taiwan, China and Vietnam.

Philippines agency qualifies four investors from five to bid for state grid company

Philippines' privatization agency Power Sector Assets and Liabilities Management Corp. has prequalified four out of the five interested investor groups for the 25-year concession to operate the National Transmission Corp.

It is PSALM's fifth attempt to auction off the concession for the grid company.

The four groups are a consortium of Monte Oro Grid Resources

Corp. and State Grid Corp. of China, a consortium of Two Rivers Pacific Holdings Corp. and Terna-Rete Electtrica Nazionale SPA, a consortium of San Miguel Energy Corp. and TPG Aurora BV, and a consortium of Citadel Holdings Inc. and Power Grid Corp. of India.

PSALM did not reveal details on the fifth group, which was disqualified. The groups have to submit the technical and financial bid on December 12.

PSALM said Monte Oro is represented by its Chairman Walter W. Brown, Two Rivers by its President Ma. K. Lim, San Miguel by Chairman Ramon S. Ang, and Citadel by Amelia S. Dela Rosa. The four representative companies are the Philippine partners in their respective consortiums and each owns a 60% stake in their consortium.

Bidders for Transco must have the experience in operating and maintaining electricity transmission systems not less than 6,000 circuit kilometers, PSALM said.

In the 2006 auction of Transco that failed, the three investor groups that had been pre-qualified were the consortium of Citadel and Terna; the consortium of Triratna Corp. Newbridge Asia IV L.P, and Malaysia's Tenaga Nasional Bhd., and the consortium of Monte Oro and State Grid. Only the Citadel-Terna consortium returned to submit a bid in the fifth auction.

Aboitiz buys 34% stake in coal plant, 232 MW, from STEAG for $92 million

Aboitiz Power Corp. of the Philippines has purchased a 34% stake in STEAG State Power Inc. from Evonik Industries AG, which was formerly known as Steag AG, for $91.9 million.

STEAG State owns and operates the 232-MW Mindanao coal-fired plant. The plant cost $305 million and began operating in November 2006, selling power under a 25-year power purchase agreement with the National Power Corp.

Erramon Aboitiz, CEO of Aboitiz Power, said the acquisition, first announced in August, was strategic for the company. "Aside from the expansion potential, the Evonik power plant is mitigating a shortage of power supply and improving the reliability of power in Mindanao." Improving the power supply in Mindanao is crucial for Aboitiz as it distributes power in the region through two utility companies, Davao Light & Power Co. and Cotabato Light & Power Co. Aboitiz is also setting up a 72-MW run-of-river plant in Davao which would be operational by 2009.

Evonik's stake in STEAG State is now reduced to 55%. The remaining 11% is held by the Philippine-based State Investment Trust Inc. Evonik's sale is in line with its global strategy to reduce its stake in its overseas ventures in the Philippines, Colombia and Turkey.

Thailand's Ratchaburi to buy 40% stake in Laos plant; to sell 10% to China investor

Ratchaburi Electricity Generating Holding Co. plans to buy 40% stake in the 1,653-MW Hongsa coal-fired project from Banpu Power Ltd. for $10 million to $16 million and is negotiating with a Chinese investor to sell 10% of that stake at a later stage.

In a news release, Ratchaburi said that after the sale the government of Laos would own 20% stake in the Hongsa project while Banpu would own 40%. Banpu Power is a wholly owned subsidiary of Thai mining company Banpu PLC.

Besides buying a stake in the power project, Ratchaburi also plans to set up a coal mining company in Laos in which it would have 37.5% stake. Banpu Power would own 37.5% of the mining company, and the rest of the mining company would be owned by the government of Laos.

Analysts said the acquisition of a coal-fired plant in Laos is crucial for Ratchaburi given the local resistance to such plants in Thailand. Ratchaburi said the 40% stake in Hongsa would boost its capacity to 5,160 MW from 4,499 MW

The $2.61 billion project, which is being developed on a build-operate-transfer basis, would begin operations in 2013. The 25-year power purchase agreement for the plant is being negotiated with the Electricity Generating Authority of Thailand.

Laos has been identified as a key power generation area for Thailand. So far Thai companies have set up only hydropower projects there, but now companies like Ratchaburi are planning to develop coal-fired plants there as well.

As for its hydropower plans in Laos, Ratchaburi plans to buy 25% stake in the 615-MW Nam Ngum-II project. The other shareholders in this project would be Ch. Karnchang, Bangkok Expressway Co., and the government of Laos. It also plans to buy 25% stake in the 460-MW Nam Ngum-III project, which is owned by the government of Laos, the MDX Group and Marubeni Corp.

Ratchaburi, Thai National, National Power IPP bids rejected; Ratch contests decision

Thailand's Energy Policy and Planning Office has disqualified the bids of Ratchaburi Electricity Generating Holding Co., Thai National Power Ltd., and National Power Supply Co. out of the 20 bids it received under the 3,200-MW independent power producers' program.

A person associated with the bidding process said the remaining 17 bids were qualified to enter the second round.

He said Ratchaburi's bid for an 800-MW gas-fired project was rejected on the grounds that more than 50% of the company's shares are owned by state-owned institutions. Under Thai Energy Ministry rules, state-owned companies are not allowed to bid for IPP projects.

At present, 45% of Ratchaburi's shares are owned by the state-owned Electricity Generating Authority of Thailand, 4.89% is held by state-owned Social Security Fund, and 2.6% by the Government Savings Bank. The rest of the shares are held by retail and institutional investors.

In response to the EPPO decision, Ratchaburi has filed a petition with Thailand's Administrative Court asking the court to tell the Energy Ministry to reinstate its bid. The official did not say when the Court would give its decision.

In its petition, Ratchaburi has said that the government holding in the company is less than 50% as the Social Security Fund is a public entity and not a state entity. The SSF is a pool to which both the employers and employees make contributions to provide compensation to employees during illness and accidents.

A Ratchaburi official said the disqualification was against public interest as it denied them a chance to access power at reasonable rates. The proposed project was to have come up at Ratchaburi's existing site and would have benefited from the existing infrastructure and good access to both the gas and electricity transmission grids, he added. Ratchaburi had submitted two bids and its bid for an 800-MW gas-fired project at Rojana Industrial Park — in consortium with Thailand's Rojana Industrial Park Ltd., Kansai Electric Power Co. and KPIC Netherlands — has been qualified to enter the second round of bidding.

The person associated with the bidding process said Thai National Power and National Power's bids were rejected on technical grounds, but did not provide further reasons. Officials at both the companies were not immediately available to comment on the disqualification.

In the second round slated for the last week of November, the investors have to submit the tariff at which they propose to sell the power developed from the projects. The winners would be announced by mid-December.

Under the government's Power Development Plan, independent power producers were invited to bid for the right to develop 3,200 MW between 2012 and 2014. Of the 3,200 MW, 800 MW has to be commissioned in 2012, 800 MW in 2013 and 1,600 MW in 2014.

EUROPE

Iberdrola sets price for public offering of 20% stake in its renewables business

Iberdrola has set a price range of between Eur5.30 and Eur7 ($7.84 and $10.35) for the 20% of its renewables subsidiary to be sold by year end, the Spanish generator said November 20.

The public share placement, totaling 844.8 million shares of Iberdrola Renovables, would represent a cash injection of between Eur4.478 billion and Eur5.914 billion.

The Spanish generator said that, of the total number of shares to be placed, 76.8 million would be allotted as a greenshoe option for the investment dealers participating in the offering. Of the remaining 768 million, 20% would be reserved for employees of Iberdrola and its subsidiaries and non-institutional investors in Spain and Andorra, 15% for institutional investors in Spain and Andorra and 65% for foreign investors.

Iberdrola Renovables, formerly Iberenova, had 7,342 MW of gross installed capacity at September 30, mostly wind farm installations.

Additionally, the company boasts a portfolio of around 41,200 MW in the planning and development stage — 21,200 MW in the US, 6,600 MW in Spain, close to 6,100 MW in the UK and around 7,350 MW in other countries.

The pending operation, first announced in May, is aimed at raising cash to fund future expansion without straining the group's finances and at increasing the subsidiary's market visibility, Iberdrola said at the time.

The Spanish generator, reacting to recent stock market uncertainty and share price oscillations, said it had no plans at the moment to delay the public placement.

Owners seek to sell Teesside Power, 1,875-MW CCGT, in northern England

Goldman Sachs and Carval Investors have launched the sale of Teesside Power, the owner of a 1,875-MW combined-cycle gas-fired plant in northeastern England, a spokesman for the companies said last week.

Investment bank Rothschild is acting as financial adviser to the owners and a sale prospectus will be issued in the coming weeks.

Goldman Sachs and Carval have been reviewing several strategic options in the past few weeks.

The plant began operation in 1993 and is supplied under a gas contract which ends next September. The gas is supplied from North Sea fields, carried by the Central Area Transmission System.

Singapore's Sembcorp, Germany's RWE and Electricite de France are said to hold long-term contracts to buy the plant's output.

While it searches for buyers, Goldman Sachs and Carval will press ahead with plans to upgrade some of the existing gas and steam turbines at the power station.

The plant currently comprises eight 152-MW Mitsubishi Heavy Industries Westinghouse 701DA gas turbines, eight heat-recovery steam generators and two 305-MW Mitsubishi Westinghouse steam turbines. Proposals have been put forward to replace the existing eight Westinghouse turbines with four new 300-MW gas turbines and two new 340-MW steam turbines.

The company is going through the pre-planning process and proposes to submit a planning application at the end of December. Teesside Power said that work is not expected to start for two years.

The company hopes to retain as much of the existing site infrastructure as is practical, including the cooling towers, electrical sub-stations, control room, office buildings, plant auxiliary systems, "black start" gas turbine, fuel gas and raw water supply infrastructure.

The upgrading work will be phased to allow part of the existing plant to remain operational during the building process of the upgrade.

UK gov't. launches tender for development of CO2 capture-and-storage pilot project

A UK government department gas has issued a tender for a carbon dioxide capture-and-storage demonstration project.

In a note published in the EU Official Journal November 20, the Department for Business and Enterprise and Regulatory Reform said it "intends to award a contract for the design, construction and operation of a project which successfully demonstrates a full chain of carbon dioxide capture, transport and storage technology."

The project would have to demonstrate the capture, transport and storage of carbon dioxide at a commercial scale and on a long-term basis, the note said.

"The Department's current intention is for the project to start demonstrating carbon dioxide capture, transport and storage by 2014. Further detail on the contract is contained in the project information memorandum, which is available on the Departmental web site: www.berr.gov.uk.

The deadline for receipt of requests for documents or for accessing documents is March 31, 2008, the note said.

In running the competition, the department is using the negotiated procedure in light of the special circumstances of the project, it said. "However, the Department reserves its position as to whether Directive 2004/18/EEC and the Public Contracts Regulations 2006 apply to this project."

Previously, the government has said the competition would only be open to projects demonstrating post-combustion technology.

Spanish generators must give up $1.8 billion to cover CO_2 emissions credits in power prices

Spain's industry ministry has determined that domestic power producers must surrender around Eur1.2 billion ($1.8 billion) in earnings related to carbon dioxide emissions charges that were built into generation prices.

The move, announced November 16 by the ministry, is aimed at recovering the value of emission credits that had been assigned for the 2005-2007 period and for which consumers ended up paying.

Even though the credits were free in theory, Spanish power producers had been required to incorporate the cost of greenhouse gas emissions when formulating the price of power sold by their various installations on the domestic market.

The Eur1.2 billion that the government plans to recoup will be deducted from the Eur3.4 billion that power producers expect to receive to make up for the tariff deficit that was racked up in 2006.

Of the total, Endesa is expected to surrender around Eur400 million, Iberdrola Eur350 million, and Union Fenosa, Enel Viesgo, HC Energia and Gas Natural the remaining Eur450 million.

Spanish energy regulator CNE has been charged with the task of calculating the specific amounts for each company and is to issue its evaluations within 15 days.

EdF may consider purchase of stake in Russian genco says head of UES

The head of Russian power monopoly UES, Anatoly Chubais, confirmed last week that French state-run Electricite de France was interested in "one of Russia's power generation companies" on offer to investors as part of the country's power sector reform.

He declined to specify which companies EdF was looking at, however.

EdF's chairman and chief executive, Pierre Gadonneix, was quoted in the *Financial Times* saying the company is "considering [being] a partner" in the privatization of the Russian electricity industry.

EdF spokeswoman Agnes Nemes said that Gadonneix' comments in the FT referred to the French utility's possible involvement in Inter RAO UES, a state-owned power exporter and importer, rather than Russia's power generation companies.

Russian business daily *Kommersant* last month reported that EdF might buy a 25% stake in Inter RAO UES.

EdF's involvement in Inter RAO as well as other Russian "opportunities" was still at an "exploratory stage," Nemes said.

Earlier this year, UES' Chubais said he would welcome foreign companies' control in two to five Russian generation businesses.

Russia has put 20 wholesale and territorial generation companies on the block as part of its efforts to unbundle the sector by July 2008.

Another French company, Gaz de France, is considering buying into West Siberian power generator TGK-10, Russian business daily *Vedomosti* said last week.

The French investors would join Italy's Enel, Germany's E.ON and Finland's Fortum, which earlier this year snapped up strategic stakes in large generation companies OGK-5, OGK-4, and TGK-1, respectively.

Russian metals company Norilsk Nickel may sell stakes in generation companies

Russian metals giant Norilsk Nickel will consider the sale of its non-core power assets if the planned spin-off of the business is not approved by shareholders, the company's CEO Denis Morozov said last week at a conference.

The comment follows speculation in the Russian press that Norilsk Nickel shareholder Mikhail Prokhorov is planning to block the planned spin-off of non-core power assets into Energopolyus.

The spin-off is to be put to a vote at an extraordinary shareholders meeting on December 14.

The Energopolyus spin-off requires approval by 75% of all Norilsk Nickel shareholders. Prokhorov holds around 25% in Norilsk directly, with a further 4% stake held by recently formed investment vehicle KM Invest.

Morozov said that he does not expect Prokhorov to try to block the Energopolyus deal, partly as the idea to spin the assets out of the main company was originally his. Moreover, the spin-off was approved at a May board meeting attended by Prokhorov, Morozov said. And also, Prokhorov was also instrumental in the purchase of Norilsk's stake in wholesale generation firm OGK-3, one of the assets to go into the planned Energopolyus business.

Norilsk's stake in OGK-3 is currently 65.2%, Morozov said, noting the Norilsk stake in OGK-3 will increase next year to around 79% when Norilsk gets OGK-3 shares in exchange for shares it currently holds in power monopoly UES.

OGK-3 operates six thermal plants across Russia, with total installed capacity of 8,497 MW.

Other assets going into Energopolyus include Norilsk's stake of 1.7% in wholesale generation firm OGK-5, Morozov said.

Energopolyus is also set to include Norilsk's respective stakes of 7.4%, 1.6% and 27.7% in territorial generation firms TGK-1, TGK-5 and TGK-14.

TGK-1 has installed capacity of 6,248 MW and operates in Russia's northwest, including St Petersburg.

TGK-5 has installed capacity of 2,467 MW. It operates 11 plants in western Russia. TGK-14 is one of the smaller generation firms in Russia covering part of sparsely populated Eastern Siberia.

Other transmission and distribution assets will be also be included.

Under current plans, Norilsk Nickel, which is the world's largest nickel producer, will retain only those power assets required to run its own production facilities.

Vattenfall enters joint venture to develop up to 1,500 MW of wind farms in Sweden

Swedish company Vattenfall and forest owner Sveaskog said the two companies have entered into a cooperation agreement that could result in 550 wind farms with a total installed capacity of 1,500 MW being built in southern Sweden.

The wind farms would be spread across five counties, the two companies said in a joint statement. Gunnar Olofsson, managing director of Sveaskog, said the plan was to lease forest areas to Vattenfall.

"In cooperation with Vattenfall we can contribute to Sweden's [energy] political target of 17 TWh/year of renewable electricity by 2016," Olofsson said in a statement.

A spokesman for Vattenfall, Erik von Hofsten, said the project would need approval from Swedish authorities, but would not give an estimated time for completion. It would "take several years," he said.

Hofsten said the project would cost around Swedish krona 20 billion (Eur2.17 billion) to finance, almost half of Vattenfall's total budget for developing wind generation until 2016 (SKr41 billion).

Sweden produced 1 TWh of wind power in 2006, according to data published by Nord Pool. Total power production was 140.3 TWh, mostly from hydro and nuclear plants.

Suez buys 50% stake in Compagnie du Vent wind generator in France for $470 million

French energy group Suez has bought 50.1% of French wind energy company Compagnie du Vent, Suez said last week.

According to Suez, the Eur321 million ($470.29 million) acquisition was made via the company's Belgian subsidiary Electrabel.

According to Suez, Compagnie du Vent has 148 MW of production capacity in operation or at an advanced stage of construction. "Its production base includes 180 wind turbines located throughout the Brittany, Languedoc Roussillon, Nord Pas de Calais, Picardy and Pays de la Loire regions," Suez said.

Suez also said Compagnie du Vent has "projects under way to increase its wind power production capacity by 2015 to nearly 2,000 MW, with the plan to give the company a 15% French market share by 2015."

According to Suez, the company is also in a biofuel diversification program, preparing the construction of a 200,000 mt/year biodiesel fuel plant at the Port of Marseille and scheduled to be in service by 2009.

Additionally, Suez said, Compagnie du Vent is engaged in solar energy with a target photovoltaic power plant installed capacity of 55 MW by 2015.

Suez said it plans to increase its investment in Compagnie du Vent to 56.8%, and that company founder Jean-Michel Germa will remain its chairman and CEO.

Not including Compagnie du Vent, Suez said it has 30 wind farms in Europe capable of generating 550 MW.

European/Middle Eastern briefs

■ German wind generator **Nordex** has signed a Eur190 million ($277 million) contract with Danish Greentech Energy Systems to supply and install 89 wind turbines with a rated output of 185 MW at wind parks in Sicily and Sardinia.

The Messina wind farm, with 21 turbines of 2.5 MW each, will be set up in Sicily, while 43, 2.3-MW turbines for the Grighine wind farm and 25, 1.5-MW turbines for the Energia Alternativa wind farms will be installed in Sardinia, Nordex said. The Energia Alternativa project is an extension of a wind farm recently built by Nordex, consisting of 14, 1.5-MW turbines.

According to Nordex, all three farms are scheduled to be in operation by the end of 2008.

■ **Enel** of Italy last week offered a total of rubles 98.43 billion ($4 billion) to buy all remaining shares in Russian wholesale generation company OGK-5.

The offer, which was expected, equates to Rb4.4275/share, Enel said.

Enel already owns 37.15% in OGK-5 and has previously said it plans to increase its holding in the company.

The purchase of the shares will be financed by existing credit lines, Enel said. The tender period runs for 80 days.

Currently, the Russian state owns 26.43% in OGK-5, a spokesman for OGK-5 said. The remainder of the company is owned by unnamed minority shareholders.

Enel already has regulatory approval for the deal.

OGK-5 has four main power plants, including 2,400 MW of gas-fired capacity at Konakovskaya GRES in the Tver Region of Central Russia; 1,290 MW of gas fired capacity at Nevinnomysskaya GRES in the Stavropol Region (Southern Russia); 3,800 MW of coal-fired capacity at Reftinskaya GRES in the Sverdlovsk Region (Urals), and 1,182 MW of gas-fired capacity at Sredneuralskaya GRES in the Sverdlovsk Region (Urals).

The Russian GRES plants are the largest in capacity of the Russian thermal plants, normally located far from built up areas.

■ Israel's **National Infrastructure Ministry** has set January as the target date for issuing an international tender for the construction of two 125-MW solar thermal power plants at Ashalim in southern Israel. The ministry said that it would choose financial and legal advisors for the tender by the end of this month. The tender will be on a build-own-transfer basis.

■ **Iberdrola** Ingeneria y Construccion, together with **GE**, has been awarded the turnkey contract to build a 1,200-MW gas-fired, combined-cycle plant in Algeria, parent company Iberdrola said November 21.

The plant, budgeted at Eur1.47 billion ($2.18 billion), would be located at the coastal city of Koudiet Edrauch in El Tarf province and is expected to take 48 months to complete.

The Iberdrola engineering and construction affiliate and GE, which was competing with a consortium led by Alstom, were selected by Algeria's state-owned gas company Sonelgaz to carry out the project.

LATIN AMERICA

Latin American energy ministers meet to discuss plan to develop grid links

Energy ministers from Bolivia, Chile, Colombia, Ecuador and Peru announced November 19 in Santiago a study into the feasibility of building interconnections between the five countries.

The countries plan to launch a tender in March to select international consultants to carry out the study, which is expected to take 10 months to complete, with the results being known by the end of next year, said Chile's energy minister Marcelo Tokman.

Developing interconnections through the region would allow countries to overcome energy shortfalls in their domestic markets by importing power from their neighbors. Argentina has partly overcome its energy shortages by importing power from Brazil and Uruguay, Tokman noted.

Chile is facing rising energy costs and possible shortfalls over the coming years as it adjusts to life without natural gas from Argentina.

Peru's Deputy Energy Minister Pedro Gamia said the country possessed 60,000 MW of hydroelectric potential in its eastern Andes, only 5% of which has been developed.

"Peru could export lots of energy to its neighbors who need it and this is a now a possibility thanks to this agreement," he said.

The countries could also pursue economies of scale with larger power projects and exploit synergies between their energy market to reduce the need for surplus capacity and generating costs.

For instance, low rainfall in one country could be offset with surplus hydropower from another, while differing time zones would reduce peak demand on an individual country's generator park.

Although the projects being lined up are not exclusively hydroelectric, the Andean nations are planning to propose a fast-track financing program using carbon credits to the European Union when leaders from the two continents meet in Lima next May, Peru's Gamia said.

Today only Ecuador has limited interconnections with Colombia and Peru.

Meanwhile, Bolivia's minister for energy and mining, Carlos Villegas, said that the project, which is being developed with support from the United Nations Development Program, was limited to exchanging electricity.

Any plans to export gas from Bolivia, which holds the continent's second largest reserves behind Venezuela, to its neighbor Chile, which is suffering acute shortages as Argentina cuts off supplies, would require discussion of a 13-point agenda drawn up between the governments of the two countries. These include the difficult issue of access to the Pacific Ocean, which Chile took from Bolivia in a nineteenth century land grab.

BHP, Pacific Hydro sign deal to build up to 100 MW of wind projects in Chile

The Chilean subsidiaries of BHP Billiton, the world's largest mining company, and Australian renewable energy company Pacific Hydro have signed a strategic agreement to study the feasibility of developing up to 100 MW of wind farms in the north of the country.

Under the deal, Pacific Hydro would study wind conditions and carry out engineering, construction and operation of the wind farms in different zones, which it is analyzing with the mining firm.

BHP Billiton will have first option to buy part or all of the energy produced by the wind farms. Site preparation will begin in early 2008, with an eye to building the projects by the end of 2009.

BHP Billiton operates three large copper mines in northern Chile — Cerro Colorado, Escondida and Spence — making it one of the largest consumers in the region, where mining accounts for more than 80% of electricity demand.

Northern Chile is facing rising power prices and a possible energy shortfall because of reduced imports of Argentine natural gas, the basis for most of the region's installed capacity.

BHP also is developing a 600-MW coal-fired plant at the northern port of Mejillones to ensure electricity supplies to its mines.

Pacific Hydro is developing a series of run-of-river hydroelectric projects in central Chile, some in partnership with Norway's SN Power, with total installed capacity of almost 1,000 MW.

Endesa Chile renegotiates power contract with hydro generator Empresa Peuenche

Endesa Chile has renegotiated its power supply contract with Empresa Electrica Pehuenche SA, one of its largest hydroelectric operations.

In a statement to Chile's securities regulator November 20, Pehuenche SA said that the new contract would run from 2008 to 2021 and would supply 1,250 GWh of electricity in 2008, rising to 1,500 GWh annually from 2009 onwards.

The energy will be priced according to marginal energy costs on Chile's central SIC grid until 2010 from which it will be fixed, indexed to variations in the US consumer price index.

The new deal follows Pehuenche's decision last September not to renew two contracts with Endesa for 650 GWh/year and 1,300 GWh/year due to expire on December 31, 2007 and March 31, 2008, respectively.

Pehuenche CEO Lucio Castro said the new deal was part of a modernization of the company's commercial policy in line with the rest of the industry and new market conditions.

Pehuenche SA operates the 566-MW Pehuenche hydroelectric dam, south of Santiago, plus the Curilinque and

Loma Alta projects, with 89 MW and 40 MW of installed capacity, respectively.

Endesa Chile owns 92.65% of Pehuenche SA.

Pacific Hydro-SN Power venture signs long-term supply contract with Chilectra

Hidroelectrica La Confluencia, a joint venture between Australia's Pacific Hydro and Norway's SN Power to develop a 155-MW run-of-river plant on the Tinguiririca River in central Chile, has signed a long-term supply contract with Chilectra, owned by the Enersis utility group, and the country's largest distribution business.

In a statement, Chilectra said that La Confluencia would supply more than 5,000 GWh over 13 years. La Confluencia is expected to produce 650 GWh annually from 2010 when construction is due to end.

"The contract with La Confluencia contributes to ensuring power supplies for Chilectra's unregulated clients in the medium term and makes viable the incorporation of new energy to the central grid," said Chilectra CEO Rafael Lopez Rueda.

The deal follows a similar contract with Hidroelectrica La Higuera project, also owned by the Tingirrica joint venture, which is due to add 145 MW from the end of 2008.

Chilectra is Chile's largest electricity distributor and supplies more 13,000 GWh each year to 1.413 million clients in and around Santiago.

NORTH AMERICA

PROJECTS

Southern Company unit and Orlando, Florida, muni are latest developers to nix IGCC project plans

Southern Power and Orlando's municipal utility has scrapped their plan to build the coal-gasification portion of their planned 285-MW integrated gasification combined-cycle plant because of their rising concern about the project's long-term cost.

"Continuing uncertainty surrounding potential state regulations relating to greenhouse gas emissions" was the primary reason that Southern Power and the Orlando Utilities Commission cited in their decision to build a conventional gas-fired combined-cycle plant at the Stanton station near Orlando instead of an IGCC facility.

The IGCC plant was to have cost $557 million and, because the facility was not planned to capture and sequester carbon dioxide, could have exposed the Southern Company subsidiary and OUC to future financial risk, Southern Power and the muni said.

An IGCC plant without CO2 capture and sequestration emits 30% less CO2 than a traditionally coal-fired plant, but considerably more CO2 than a gas-fired combined-cycle plant, said Southern spokesman Mike Tyndall. Deciding to fire the plant with natural gas instead of gas from coal, therefore, would reduce the plant owners' exposure to the financial risks associated with future carbon laws and regulations.

The decision to cancel the coal-gasification portion of the plant "had to be made now, before major financial commitments were made" on the coal-gasification part of the overall project, OUC said in a written statement.

Florida Governor Charlie Crist in July issued several executive orders related to greenhouse gas emissions, including a mandate that utilities in the state cap such emissions at their 2000 level by 2017, then reduce them to their 1990 level by 2025 and to 20% of their 1990 level by 2050 (*GPR*, 12 July, 16).

Crist's orders were "the main factor" in the partnership's decision to cancel the coal-gasification portion of the combined-cycle plant near Orlando, said Southern's Tyndall. "Those executive orders created economic uncertainty and risks" the partners decided they could not take, he said.

"The regulatory landscape has changed considerably since we started developing [the IGCC] project three and a half years ago," said OUC CEO and General Manager Ken Ksionek. "There is a lot of uncertainty now" about future regulations regarding greenhouse gas emissions and the need for carbon sequestration, he said.

Just last month, Tampa Electric scrapped its plan to build a 630-MW IGCC plant at its plant in Polk County and said it instead would explore alternatives such as a gas-fired combined-cycle plant, energy efficiency and conservation programs, and renewable energy.

Tampa Electric said that that primary reasons for its decision included continued uncertainty related to carbon dioxide regulations and related cost increases (*GPR*, 11 Oct, 16).

Some IGCC projects continue to move forward, however. American Electric Power plans to build two 600-MW-plus IGCC plants, one in New Haven, West Virginia, the other in Meigs County, Ohio. And Duke Energy Indiana is working on a 630-MW IGCC plant in Edwardsport, Indiana. In Texas, Hunton Energy is developing a 1,200-MW IGCC plant in Brazoria County, and Babcock & Brown has said in may build up to 800 MW of IGCC capacity at a site in Pampa.

Energy Future Holdings dismisses claims it is reneging on promise to shut coal projects

Energy Future Holdings, as TXU is now known, is dismissing a claim by the Lone Star Chapter of the Sierra Club that the Texas generation giant is backing away from its promise not to build eight 858-MW coal-fired plants in the state.

The Sierra Club chapter said that EFH recently asked the two Texas administrative law judges who had been considering TXU's now-suspended permit applications for the eight coal plants to dismiss the applications "without prejudice," not "with prejudice," as the chapter would have preferred.

"If the new TXU is indeed committed to a clean energy future and to the fight against global warming, then the company should agree to dismissal of its permit applications for those units without the opportunity to re-submit them later," the Lone Star chapter said in a written statement.

Ilan Levin, an Environmental Integrity Project attorney representing the Sierra Club chapter, said that the chapter has asked the ALJs to dismiss the EFH/TXU applications with prejudice, which he said is "the normal practice" in Texas.

Dismissing the applications without prejudice, Levin said, "would make those applications 'less dead'" and make it easier for the coal projects to be revived.

Levin acknowledged that it is unlikely that the current owners of EFH would seek to revive the projects, which the TXU buyers promised to terminate when they reached an agreement to acquire TXU this past February (*GPR*, 1 March, 1). The acquisition closed last month. "But we don't know who might buy [EFH/TXU] in the future or if they would keep the promise the [current owners] made."

Levin added, "We want an enforceable commitment" not to pursue the development of the eight coal projects. "As soon as we have that, we will back away."

EFH spokeswoman Lisa Singleton said that the company is "continuing to fulfill the commitments made as a part of the merger transaction. We committed to terminate the permits that had been filed, and we have done so."

Sunflower Electric files suits against Kansas for permits on 700-MW coal-fired plants

Sunflower Electric Power, the Kansas electric cooperative group, said that it has filed lawsuits aimed at overturning the Kansas Department of Health and Environment's October 18 rejection of an air permit for two 700-MW coal plants in western Kansas on greenhouse gas grounds.

Sunflower filed one of the suits at the Kansas Court of Appeals and the other at the Kansas District Court of Finney County last week, following Sunflower's November 1 administrative appeal to the KDHE.

Sunflower asserts that KDHE and Kansas Health and Environment Secretary Roderick Bremby had no authority under state law to deny a permit for the two proposed coal plants in Finney County because of the CO2 and other greenhouse gases that the plants would emit. Neither US nor Kansas law currently treats CO2 as a regulated pollutant, the co-op group said.

In separate filings, the Finney County Board of County Commissioners and the Garden City Chamber of Commerce filed suit to vacate the denial order in the Kansas Court of Appeals. Tri-State Generation and Transmission, a Colorado generation and transmission co-op that is a participant in the coal project, also filed suit at both the Kansas Court of Appeals and the District Court in Finney County.

Mark Calcara, Sunflower's vice president and general counsel, said he believes Bremby's decision was wrong as matter of law and was arbitrary and capricious.

Bremby cited the US Supreme Court's recent decision in Massachusetts v. US Environmental Protection Agency that carbon dioxide meets the broad definition of an air pollutant under the federal Clean Air Act, noting that, in his view, the Kansas Air Quality Act "similarly has a broad definition of what constitutes air pollution."

Bremby's denial of the air permit application raised alarm among several key state legislators, several of whom have said they are developing legislation to prevent such denials in the future, or possibly undo the permit denial retroactively.

Spokesmen for the KDHE did not return a telephone call seeking comment.

Illinois backs Ohio over Texas as site for $1.4 bil FutureGen clean coal project

Illinois last week said Ohio had become the latest state to back its campaign to locate a FutureGen clean coal plant in Illinois.

Ohio joins Pennsylvania, Indiana, Kentucky and Wisconsin in backing the state in its fight against Texas for siting of the $1.4 billion project, it said.

Two sites in Tuscola and Matoon in Illinois, along with two in Texas, are the four finalists for the site. The Department of Energy is set to announce the winner in mid-December.

Indiana regulators approve 630-MW IGCC planned by Duke Energy in Knox County

Indiana regulators on November 20 unanimously approved a controversial 630-MW, $2 billion integrated gasification combined-cycle project planned by Duke Energy Indiana.

The project has drawn strong support from Republican Governor Mitch Daniels, but has split the environmental community.

Duke wants to build the plant at the site of its aging 160-MW Edwardsport coal-fired station in Knox County, Indiana.

Commissioners found Duke appropriately documented the need for additional generation capacity and met the statutory requirements necessary for the project's approval. The commission allowed the incentive of timely recovery of project costs but denied an incentive for an enhanced return on equity, finding the cost recovery incentive adequate to compensate the company and its shareholders.

According to the IURC, the project is expected to result in an approximately 16% rate increase for Duke ratepayers in Indiana. If the project's cost exceeds the $1.98 billion authorized by the commission, Duke will be required to justify the additional amount and seek approval in a separate proceeding to recover the higher costs.

The project has won support from the Clean Air Task Force and American Lung Association but is opposed by several other environmental groups, including the Sierra Club and Valley Watch.

Vectren, an Indiana utility company, withdrew as a minority partner in the project last summer, saying the IGCC plant was "not compatible with the expected demand" on its system.

Duke hopes to place the plant in commercial operation early next decade.

Indiana regulator approves wind farm project, 750-MW, proposed by BP Alternative Energy

BP Alternative Energy North America's proposed 750-MW Fowler Ridge Wind Farm LLC won approval November 20 from the Indiana Utility Regulatory Commission.

The project is expected to be developed in phases, with the initial 200-MW portion in commercial operation by the end of 2008. In August, Indiana Michigan Power, an American Electric Power subsidiary, entered into a 20-year agreement to purchase 100 MW from the wind farm.

The wind farm's output will be sold on the wholesale market and Fowler Ridge does not intend and is not authorized by the IURC to sell any electric generated from the facility to the public on a retail basis, the commission noted.

Norton Energy Storage continues 'dialogue' with suppliers for Ohio compressed air project

Norton Energy Storage is participating in "ongoing dialogue" with equipment vendors for a proposed compressed air energy storage project in Summit County, Ohio, but has "no commitments" yet, a Norton official said in late November.

"There is activity going on," said John Strom, chairman of the board of managers of NES, a 2,700-MW CAES/gas-fired combustion turbine generating project. "But there is nothing definitive." Strom indicated the situation could change in early 2008, but provided no details.

"People are starting to think more about how the various systems are going to handle an increasing amount of renewables," he said.

NES told the Ohio Public Utilities Commission earlier this year the unusual project made "very favorable progress" during 2006 and was poised to move forward in 2007. NES "significantly advanced" commercial tolling discussions in 2006 and anticipated "successfully completing" tolling negotiations in 2007, the company said.

But finding vendors to supply the necessary equipment for the approximately $1.5 billion project has been difficult.

The project, owned by private equity funds managed by Haddington Ventures, would be developed over a several-year period, in 300-MW increments.

Dominion set to receive early site permit from NRC for possible nuclear power site

Dominion Nuclear's North Anna nuclear plant will be the third early site permit holder when Nuclear Regulatory Commission staff issues one to it within the next 10 business days, the NRC directed in a vote November 20.

Dominion submitted its ESP application in September 2003, seeking approval of the North Anna site near Louisa, Virginia, for possible future construction of a new plant.

The company plans to file by the end of the month a combined construction permit-operating license for GE-Hitachi Nuclear Energy's Economic Simplified Boiling Water Reactor. Dominion will be the lead applicant for the ESBWR design. Exelon Generation received an ESP for Clinton on March 15, and Entergy's System Energy Resources unit was issued an ESP for Grand Gulf on April 5.

NRC staff currently has one other ESP application under review, for Southern Nuclear Operating's Vogtle plant. That review is expected to be completed next year.

Constellation, EdF ask Maryland approval to add 1,600-MW nuclear unit at Calvert

UniStar Nuclear Energy, a joint venture of Constellation Energy and Electricite de France, filed an application in Maryland to build a 1,600-MW nuclear plant at Constellation's Calvert Cliffs nuclear station.

UniStar has already submitted a partial Combined License Application to the Nuclear Regulatory Commission for the Maryland plant, and it plans to submit the remainder of the application by March 2008.

In Maryland, the partners are seeking a Certificate of Public Convenience & Necessity in Maryland, and requested a decision by December 2008. It will address air, water, wetlands and socio-economic impacts, as well as the reliability of the electric system. The CPCN process in Maryland allows public comment.

UniStar has not yet estimated the cost of the new Calvert Cliffs unit, but spokeswoman Lori Vidil said UniStar previously calculated an "overnight levelized cost" of $2,400/kW for a four-unit station, in 2005 dollars. It will update that figure in 2008. An overnight cost estimates the expense as if no interest were incurred during construction.

Michael Wallace, UniStar chairman, said the plant could help meet the region's need for baseload power in an "economic and environmentally sound" way. Volatile energy prices make the nuclear option attractive, and it is preferable to coal because of "significant environmental costs" from existing and expected regulation, he added.

The final decision on whether to build will depend on the availability of federal loan guarantees, as well as state and local tax policies, Wallace said. The Calvert County Board of Commissioners has endorsed the proposal, UniStar noted.

Constellation operates two nuclear units, representing about 1,700 MW, at Calvert Cliffs. They began operating in 1975 and 1977. In 2000, Constellation obtained a 20-year extension on the permits, letting the plants operate until 2034 and 2036.

UniStar is also considering adding an Areva reactor at the 1,750-MW Nine Mile Point nuclear station in New York, of which Constellation owns about 90%. It has not yet filed with the NRC for that project.

Competitive Power Ventures plans peaker of up to 500 MW near Cambridge, Ontario

Competitive Power Ventures said last week that its CPV Canada Developments unit is developing a gas-fired peaking plant of up to 500 MW in the Township of North Dumfries near Cambridge, Ontario.

Duncan McEachern, vice president of Competitive Power Ventures, said in an interview that CPV Canada has secured an option on a site for the proposed combustion turbine-based facility, is proceeding on a required environmental assessment, and has asked Ontario's Independent Electricity System Operator to study the impact of the project on the provincial grid.

McEachern said that CPV Canada plans to advance the project by responding to a solicitation that the Ontario Power Authority is expected to issue in 2008 for 450 MW of peaking or simple-cycle power the province will need in Ontario's Kitchener-Waterloo-Cambridge-Guelph region by 2012 to keep pace with load growth there.

The Competitive Power Ventures executive said that OPA is expected to select a solicitation winner — and enter into a 20-

year power purchase agreement with that winner — in 2009. If the CPV Canada project is selected, McEachern said, he anticipates that the peaking plant would begin operation in 2011.

Asked if he was aware of other peaking projects under development in the Kitchener-Waterloo-Cambridge-Guelph area, he said, "I don't know of any, but there may be others." If so, none have applied yet to the IESO for a grid connection assessment.

McEachern noted that CPV Canada is in earlier stages of developing two other projects in Ontario. One is another gas-fired plant, and the other is a wind project. He declined to provide specifics.

Silver Spring, Maryland-based Competitive Power Ventures, which is best-known for developing gas-fired plants in the US, was drawn to Ontario because its electricity market is a "hybrid" of regulation and competition that "offers 20-year PPAs backstopped by the Ontario Power Authority," McEachern said.

OPA CEO Jan Carr indicated in September that the agency plans to competitively secure the entire 2,150 MW of new gas-fired capacity that OPA has determined needs to be online within four specific areas by year-end 2014.

PG&E seeks PUC approval to build a 657-MW gas-fired plant in Colusa

Pacific Gas and Electric last week submitted a proposal to the California Public Utilities Commission seeking approval to build a 657-MW gas-fired combined-cycle project in Colusa, California.

In 2006, The PUC approved an agreement under which the project would be built by E&L Westcoast Holdings, a partnership of Competitive Power Ventures and affiliates of ArcLight Capital Partners and General Electric, and then transferred to PG&E, which would own and operate the plant. The project was deemed "data adequate" by the California Energy Commission late last year (*GPR*, 16 Nov, 20). But PG&E said E&L recently told the utility that it plans to terminate the agreement.

"Rather than allow the project to fail," PG&E said it has executed an agreement with E&L to acquire the assets and permitting for the project, the utility said in its filing with the PUC. This approach is needed to ensure that the facility will be operational in 2010, PG&E said.

The California Energy Commission is also reviewing the project, PG&E said in its proposal to the PUC.

PG&E said it expects that project costs are not likely to exceed the $673 million cost cap approved by the PUC in 2006.

Calpine's 600-MW Russell City project faces challenge from Alameda County, California

The County of Alameda, California, has petitioned the California State Supreme Court asking for a writ of mandate that could threaten the viability of 600-MW Russell City Energy Center project.

Alameda is seeking to force the California Energy Commission to reopen its proceeding and hold further evidentiary hearings to amend Calpine's license for the project (S157627).

The CEC filed a statement opposing the petition on November 5, which did not become public until November 15. Alameda claims it was not given adequate notice to participate in the hearings.

The CEC granted Calpine an amendment on September 26 following a final public hearing allowing the site of the gas-fired combined-cycle project to be moved slightly (*GPR*, 4 Oct, 12). The CEC turned down a direct request for new evidentiary hearings from the county in early October, saying the county had direct and actual notice of the 10-month long proceeding and that the county did participate through staff and advisory agencies.

The county filed its petition with the State Supreme Court on October 26.

Calpine applied to the CEC in November 2006 for an amendment to its license, originally granted in September 2002, to move its project site 1,300 feet. In the 10-month amendment review, the only controversial issue that arose had to do with the impact the plant's cooling tower plumes would have on aircraft flying into and out of the local airport.

The Federal Aviation Administration eventually concluded that the risk was low, and Calpine successfully argued that a long delay would threaten the plant's viability. Calpine has a power purchase agreement with Pacific Gas and Electric and could face fines or cancellation of the contract if the plant is not in operation in 2010.

Calpine would not comment on the implications a State Supreme Court hearing of the petition might have on construction start-time since the court has not yet ruled if it will hear the petition.

CONTRACTS

Nevada PUC approves three 20-year PPAs between Nevada Power, geothermal developers

The Nevada Public Utilities Commission has approved three 20-year geothermal power purchase contracts totaling 139.5 MW between developers and Nevada Power, a Sierra Pacific subsidiary.

The geothermal contracts include the output from a 62-MW plant that Vulcan Power plans to build near Fallon, Nevada; a 46-MW plant that TG Power intends to build near Tuscarora, Nevada; and a 31.5-MW plant Ormat expects to build in Lander County, Nevada. All of these projects are in northern Nevada. Terms of the contracts are confidential.

The PUC gave Nevada Power permission to sell the electricity from the geothermal plants to Sierra Pacific Power, its sister utility in northern Nevada. Nevada Power will also use renewable credits from the contracts to help meet Nevada's renewable portfolio standard, which climbs to 20% by 2015.

SECONDARY MARKETS

FERC approves Entergy's planned purchase of 310-MW gas plant in Louisiana from Dynegy

The Federal Energy Regulatory Commission approved Entergy Gulf States planned acquisition of Dynegy's 310-MW Calcasieu gas-fired peaking plant in southwestern Louisiana on

November 15.

The acquisition, which had been opposed by Occidental Chemical, does not harm competition in the region, FERC said, since historically the unit has run for only about 50 hours a year "and Entergy Gulf States has no incentive to withhold the facility from the market."

Entergy and Dynegy announced their $57 million sale agreement in February. Entergy said at the time that the plant's location "is clearly advantageous because of its close proximity to large customer loads with large potential load swings. The quick-start nature of Calcasieu allows it to be dispatched with short notice and will be beneficial due to limitations on the ability to import power into the region."

The company said it would spend about $6 million to upgrade the plant.

Entergy and Dynegy still await approval from the Louisiana Public Service Commission, which also must exempt the transaction from its rules requiring acquisitions of power to be solicited from the marketplace.

The PSC staff has recommended a "provisional" approval of the exemption with the idea that the sale can actually be market-tested during the PSC's certification process. That process gives potential competitors an opportunity to identify a better option available to Entergy Gulf States, Matthew Kahal, an outside consultant to the staff, said.

Energy Investors Funds completes purchase of Cogentrix Energy holdings from Goldman

Private equity fund manager Energy Investors Funds on November 16 said that its United States Power Fund III completed the acquisition of 80% of Cogentrix Energy's interest in 14 power plants. Terms of the deal were not disclosed.

EIF noted that the purchase encompasses a net 2,331 MW of capacity. EIF said that Cogentrix will retain a 20% minority interest in the positions being sold and will provide management services to the plants as well. The Cogentrix name was not sold.

The acquired portfolio consists of power plants in 12 states that sell substantially all of their generation capacity under mid- to long-term power purchase agreements or tolling arrangements to local counterparties.

EIF was founded in 1987 as a private equity fund manager focused exclusively on the independent power and electric utility industry. Cogentrix is a wholly owned subsidiary of Goldman Sachs.

SOLICITATIONS

BC Hydro releases draft terms of RFP for about 1,000 MW of 'clean power'

BC Hydro has released long-awaited draft terms and conditions to developers that plan to bid in its request for proposals for 5,000 GWh or the equivalent of about 1,000 MW that are needed to help ease a power crunch, said the Vancouver, British Columbia-based utility.

The focus of the RFP or the "Clean Power Call" will be for larger projects such as hydroelectric or wind with extended service dates. BC Hydro imports about 15% of the power needed domestically and it expects serious deficits by 2016.

Projects must be in operation between November 1, 2010 and November 1, 2016. Power purchase contracts would be for seasonal and hourly firm energy, and non firm energy would be considered under certain conditions.

A provincial government goal is to achieve energy self sufficiency. A contract provision would enable BC Hydro to acquire a power project at the end of the power purchase contracts that could range from 15 to 40 years. BC Hydro said that it is seeking input from independent power producers now regarding when and if it should acquire projects and if so, how price should be evaluated.

The utility plans to file for approval for the RFP with provincial regulators in late 2007 and issue the solicitation in the spring of 2008. The timing is dependent upon completion of the review of the bid package by the British Columbia Utilities Commission.

BC Hydro also released details of its proposed standard offer in which developers with "clean energy" projects 10 MW or less can skip the RFP process and apply directly to BC Hydro. The program offers a standard contract with set prices and a streamlined administrative process. Details are available at www.bchydro.com/standardoffer and www.bchydro.com/cleanpowercall.

Xcel releases long-range resource plan that call for it to own more power plants

In a strategy shift, Xcel Energy last week filed a long-range resource plan with Colorado regulators that calls for the utility to build plants on its own or buy them from merchant generators.

The plan, released last week, call for Xcel to cut its greenhouse gas emissions in Colorado by 10% below 2005 levels by 2015.

If approved by the Colorado Public Utilities Commission, Xcel would retire two coal-fired plants totaling 229 MW and replace them with a 480-MW gas-fired plant it would build itself. Xcel said it would retire its Arapahoe station in Denver and Cameo plant east of Grand Junction.

The utility company would also double its demand-side management programs to nearly 700 MW. Xcel would also add 1,050 MW of renewable generation in Colorado by 2015 through a combination of building the resources itself, buying them from independents, or buying renewable power from independents.

Through previous resource plans, Xcel has contracted to buy the output from fossil-fueled and renewable merchant projects. In 2006, Xcel bought 53% of its capacity from independent producers, according to the resource plan. Now, the utility wants to add rate-based generation to "rebalance" its portfolio to reduce its imputed debt and keep itself attractive to shareholders.

Xcel plans to issue a 300-MW wind request for proposals in January and will seek to own at least half the capacity from bidders. It will also issue a 25-MW “central” solar RFP in January. Those RFPs would be followed up with a 1,000-MW “all-source” RFP with bidders required to sell existing or new plants to the utility. The all-source RFP would include a set-aside for a 200-MW utility scale solar project. The utility will not accept any coal-fired bids unless they capture at least half of the carbon dioxide emitted by the project.

Xcel plans to file another resource plan in 2009, two years ahead of schedule, to provide options and make recommendations to put the company on a path to reducing GHG emissions by up to 20% by 2020, a goal recently set by Colorado Governor Bill Ritter. Xcel expects GHG reducing technology, like integrated gasification combined-cycle, to be more widely available in a couple years. Xcel is planning to take 150 MW from an integrated gasification combined-cycle plant in 2016, according to the resource plan.

Xcel’s proposed resource plan represents a major shift. The company’s 2003 resource plan would have increased carbon dioxide emissions by 20% by 2020, according to Richard Kelly, Xcel’s chairman, president and CEO.

Georgia Power issues solicitation seeking resources from wind and solar power projects

Georgia Power on November 19 issued a solicitation for power from wind and solar projects to support the utility’s retail green energy program, under which customers can purchase blocks of green power.

In the request for proposals, Georgia Power is seeking offers to provide up to 3,500 MWh/year from wind turbines and up to 500 MWh/year from solar facilities. Interested parties may bid in minimum quantities of 100-MWh blocks to be supplied for a period of 10 years, the utility said.

Georgia Power noted that the wind turbines and solar facilities can be located either within the Southern Company control area or in adjoining control areas, but must be located in one of the following states: Georgia, Alabama, Florida, Kentucky, Mississippi, North Carolina, or South Carolina.

Power should be deliverable starting by October 1, 2008, although proposals for projects that would begin delivering power after that date will be considered.

The utility noted that it “is contemplating development of a self-owned solar resource to meets its renewable needs and may select a proposal from the bids received, its self-owned solar resource, or a combination of the two.”

Bids are due January 7, and a short list will be named on or about February 29, the utility said. Contracts with the winning bidders will be filed at the Georgia Public Service Commission in late March.

Georgia Power said that a bidders’ conference will be held in Atlanta on December 6. Additional information about the RFP and the bidders’ conference has been posted at www.georgiapower.com/greenenergy.

Georgia Power said that its year-old retail green power program, which currently is based on power from landfill gas-fired plants, already is 83% subscribed, and that new renewable sources are needed.

Missouri muni Kirkwood plans solicitation for 69 MW deliverable from January 2009

Kirkwood Electric Department is seeking about 69 MW of capacity and 258 GWh of associated energy, plus scheduling and load following services beginning January 1, 2009, according to a request for proposals issued this week by the Kirkwood, Missouri, municipal utility.

Through the RFP, Kirkwood wants to replace a full requirements contract the utility has with St. Louis-based AmerenUE, according to the RFP released November 19. The 11-year expires December 31, 2008.

Kirkwood will consider proposals from utilities, independent power producers, power marketers, energy service companies and others. The utility will consider a range of term lengths for the contract, as well as both power purchase agreements and options to own resources.

Kirkwood is particularly interested in proposals for full requirements power and/or other services needed to serve its total load requirements. Bidders must also be able to integrate Kirkwood’s 12.5-MW purchase of the Prairie State Energy Campus Units 1 and 2, for a total of 25-MW, which are expected online in August 2011 and May 2012, respectively. Kirkwood may accept a combination of alternatives from one or more suppliers. Bids are due December 18. Kirkwood expects to award a contract by mid-July.

For more information, contact Chris Dawson at GDS Associates, Suite 800, 1850 Parkway Place, Marietta, Georgia, 30067, phone: 770-425 8100, fax: 770-426 0303, e-mail: chris.dawson@gdsassociates.com. The RFP is available online at www.gdsassociates.com/rfp/rfp.html.

PacifiCorp petitions Oregon, Utah regulators to revise already closed 1,700-MW solicitation

PacifiCorp has petitioned regulators in Oregon and Utah for permission to revise a 1,700-MW solicitation that the utility company issued in April and which closed in June.

The changes were denounced by the Oregon Public Utility Commission’s staff and independent evaluators hired by PacifiCorp to review submitted bids in Oregon. Utah regulators are scheduled to hold a hearing on the proposal next week.

The independent evaluators, Accion Group and Boston Pacific, said in a filing with the Oregon PUC, “the bottom line is that we oppose PacifiCorp’s proposed changes. Our opposition reflects our view that the proposal is unnecessary, unfair to existing bidders, and potentially harmful to ratepayers.”

PacifiCorp wants to extend the RFP deadline to January in order to attract a “more robust pool of bidders.” PacifiCorp also wants to add two gas-fired benchmark resources with a 2012 in-service date, and it wants to hold bidders to their prices until January 2009, instead of June 2008, and

PacifiCorp launched the RFP in April 2007, despite the Oregon PUC’s refusal to approve it because, the PUC claimed, PacifiCorp failed to justify the need for 1,109 MW of the resources (*GPR*, 12 April, 16).

The Oregon PUC’s staff said its first concern is that

PacifiCorp "cannot maintain a fair process when, mid-way through it, the company changes the rules to its apparent benefit. Bidders are not similarly afforded such an option."

The independent evaluators believe PacifiCorp's motivation is that "PacifiCorp has doubts about the viability of is 2012 benchmark plant," a 340-MW share of the Intermountain Power Agency's proposed Intermountain Power Project Unit 3, a coal-fired plant to be located in Utah. The Los Angeles Department of Water and Power has said it no longer plans to take a stake in the plant due to new California carbon laws.

Nova Scotia Power is negotiating PPAs representing 240 MW of wind power

Nova Scotia Power on November 19 said that it is negotiating power purchase agreements representing 240 MW of wind power, or 110 MW more than the 130 MW it had been seeking in its February solicitation.

Nova Scotia Power declined to name the developers, explaining that negotiations on the PPAs continue. The utility did say, however, that the 240 MW of wind turbines would be at a total of eight sites. The new wind turbines are scheduled to begin commercial operation by year-end 2009.

Nova Scotia Power also said that the selected wind projects represent a capital investment of about C$500 million (US$508 million), and that the PPAs for the energy produced would be worth about C$1.5 billion over the life of the contracts.

At an event in Brookfield announcing the solicitation result, Nova Scotia Energy Minister Richard Hurlburt noted that the province has some of Canada's best wind sites, and that "by 2013, nearly 20% of all Nova Scotia 's electricity will come from green sources like wind." Under Nova Scotia's new renewable portfolio standard, which became effective on February 1, investor-owned Nova Scotia Power and the province's six municipal utilities must secure 5% of their electricity needs in 2010, 2011 and 2012 from low-impact renewable sources that come online after 2001, and 10% of their needs from such facilities in 2013 and beyond (*GPR*, 1 Feb, 22). The RPS rules include a stiff penalty: Utilities that fail to comply with the 5% and 10% requirements will be fined at much as C$500,000/day.

Nova Scotia Power previously has signed 15-year PPA for 170 MW of wind power, and has said that it will need to add another 270 MW beyond that by 2013 to comply with the RPS.

MARKETS & GRIDS

Merchant generators support proposal to end rate pancaking in the Southwest

Merchant generators are supporting a plan by WestConnect to launch a two-year, flat transmission tariff for moving electricity across a large swath of the Southwest.

The experimental transmission rates would end rate pancaking, the accumulation of fees when electricity moves through multiple transmission systems. "Any move to eliminate pancaking is a good thing, especially around the Palo Verde hub," said Greg Patterson, executive director of the Arizona Competitive Power Alliance, which represents independent power producers.

WestConnect, made up of 12 utilities, the Transmission Agency of Northern California and the Western Area Power Administration, plans to ask the Federal Energy Regulatory Commission in early 2008 to approve the plan, Charles Reinhold, the transmission group's project manager, said November 19. If approved, new rates could take effect late next year, he said, noting that WestConnect does not want to launch the new tariff during the peak summer months.

Under the two-year trial, WestConnect will offer two flat rates, one for transactions involving "jurisdictional" and non-jurisdictional utilities, like cooperatives and municipal utilities, and one if only jurisdictional utilities are involved.

As an example, WestConnect estimated a regional jurisdictional rate of $5.03/MWh. A transaction from Arizona Public Service to Public Service Company of Colorado would currently include charges of $3.50/MWh for APS and $3.69/MWh for PSCo, totaling $7.19/MWh for the pancaked rates. The experimental rate would be $2.17/MWh, or about 30%, less expensive. Supporters of the plan believe that the reduce costs may stimulate transactions by creating lower cost pathways to high-priced markets.

The experiment contains one key risk: without increased transmission transactions, revenue would fall for transmission providers, Reinhold said. Participants will have the option of leaving the experiment after one year.

The group expects, however, that with lower rates there will be more transactions, he said. A year ago, Tri-State Generation & Transmission Association, a wholesale cooperative based in Westminster, Colorado, started discounting their transmission rates and saw a jump in reservations, he said.

Meanwhile, WestConnect is working with the National Renewable Energy Laboratory on a study looking at the costs and operating issues of integrating wind and solar capacity across a wide region of the Southwest. The study, expected to be finished in early 2009, will look at the effects of 20% to 30% renewable capacity in the region, Reinhold said.

The study will examine the possibility that geographically diverse wind and solar resources may balance their variability. It will also look at ways that hydroelectric resources may help integrate wind and solar resources.

California grid could be compromised by closure of plants with once-through cooling systems

A new California Independent System Operator study plan contends that as many as 66 older power plants in the state with an aggregate capacity of 17,126 MW might close and reliability of the power grid may be compromised if the state orders the phasing-out of once-through water cooling systems.

The ISO study plan on how to modernize or eliminate and replace older power plants that use once-through water cooling systems is being undertaken because the California

State Water Resources Control Board has begun drawing up regulations that could limit or eventually eliminate once-through systems.

The study plan will be used as a guide by the ISO and the major electric power utilities in California as they develop a comprehensive plan for generators to use in deciding to update or close and replace plants that use once-through cooling systems.

The study group, comprising Cal-ISO, the California Energy Commission, Pacific Gas and Electric, San Diego Gas & Electric and Southern California Edison, will recommend how plant owners and operators can facilitate the retirement and replacement of some of the current older thermal units that use once-through cooling systems.

"We need to have a comprehensive plan in place to make sure we understand the implications for reliability on the grid should these plants close," said Cal-ISO spokesman Gregg Fishman. "With that information, we and others can begin to plan for replacing the power generated by these plants with either additional transmission capacity, new power plants built locally, or, in some cases, retro-fitting the existing unit to reduce its environmental impact."

The ISO study plan was written by Larry Tobias and Luba Kravchuk of the ISO's regional transmission planning north division. While not taking a position for or against requiring power plants to cool their generators with water contained in a closed system loop, the two ISO engineers pointed out that doing so could "require significant retrofit of aging power plants using once-through cooling."

Such retrofits would be "very limited and very expensive" and, therefore, the "stringent regulations" that the state might call for "may have the effect of forcing the retirement of aging and less efficient power plants that cannot sustain the economic impact of expensive compliance," Tobias and Kravchuk wrote.

Even if such retrofits are "feasible, effective and have acceptable cost," such retrofits typically results "in material heat rate penalties and de-rating of peak generation capacity," the engineers wrote. "However, it must be noted that older plants may run much less often than new plants with better heat rates. Thus the effects of replacing older plants with newer plants may not lessen the total emissions in an optimized or economically dispatched system."

Also, "depending upon how these polices are implemented," there is the potential that a number of existing thermal generation units could be retired, the engineers wrote. If enough older plants shut down for good, "transmission reinforcements" that would entail the construction of new power corridors to bring in power, "and/or new generation will most likely be needed to maintain grid reliability and to allow for the import" of more energy into the state, Tobias and Kravchuk wrote.

"California's demand for energy is growing at roughly 1,000 MW per year. Keeping pace with that growth, while simultaneously managing the retirement of older power plants is going to require a coordinated effort involving various state agencies and the entire energy industry in California," Fishman said.

MISO completes testing of central market for ancillary services; aims for June '08 launch

The Midwest Independent Transmission System Operator said this week that it has successfully completed a phase of testing for its planned ancillary services market, with the grid operator and market participants jointly running a market simulation.

"This first round of testing was a great success for the Midwest ISO and our stakeholders," said Roy Jones, executive director of the ASM project, in a press release. "Data moved back and forth smoothly with very few functional issues."

The plan for a centralized ancillary services market has a fair amount of tentative support from market participants, but it is still being shaped up amid debates over various elements. MISO is aiming for a June 1, 2008, launch, pending approval from the Federal Energy Regulatory Commission as well as final blessings from stakeholders.

The just-completed round of testing simulated many of the data transactions, processes and procedures that will be in place when the regional transmission organization becomes the balancing authority and launches the market for ancillary services.

MISO said the objectives of this round of testing were to provide a realistic simulation; to demonstrate the infrastructure required for MISO to support balancing authority functions; to test system interactions between MISO and market participants, and to evaluate potential data processing issues.

The test "met these objectives and demonstrated the Midwest ISO's ability to operate the new ancillary services market," the ISO said.

At present, 24 balancing authorities within the Midwest grid operator manage ancillary services. The services to be centralized include spinning reserves (synchronized to the grid and available for use within 10 minutes), supplemental reserves (synchronized or not, but available within 10 minutes), and regulating reserves (constantly available).

FERC this week ordered a technical conference on questions of market power and mitigation in the proposed ancillary services market. A date was not immediately set for the conference.

An analysis by MISO's independent market monitor has indicated that several of the sub-regional zones within the regional transmission organization have the potential for market power, and filings by market participants have expressed strong reservations about the proposals for coping received from the grid operator and its IMM.

"There are aspects of Midwest ISO's filing that require further explanation," FERC said in its order. "For example, it is not clear that the geographic submarkets the IMM uses will be the actual geographic submarkets since the Midwest ISO proposes to modify the reserve zones quarterly."

FERC accepts MISO's plan for continued grandfathering of transmission contracts

The Federal Energy Regulatory Commission on November 15 accepted the Midwest Independent Transmission System Operator's compliance plan that will allow for continued "grandfathering" of transmission contracts that have been carved out of the region's energy markets.

Specifically, FERC at its open meeting in Washington approved extending the carved-out grandfathering of transmission contracts beyond their February 1 expiration to preserve the bargains of the contracting parties, and further found that the markets will continue to operate in an efficient and reliable manner with the carve-outs in place (Docket No. ER07-532-000).

MISO now has 101 carved-out grandfathered transmission agreements or GFAs, about 6.7% of total load. "The number will continue to decrease over time, which results in a more reliable Midwest ISO system," FERC's order states.

The commission also noted that that there is "a generally high level of scheduling accuracy related to carved-out GFAs and that [Midwest ISO] has not found any instances where a reduction of firm transmission rights was significantly impacted by carved-out GFAs."

With FERC approval, MISO in 2004 replaced its open access and transmission tariff with an open access transmission and energy markets tariff. The tariff provided for market-based congestion management and energy markets in the MISO region, including day-ahead and real-time energy markets, locational marginal pricing and a market for financial transmission rights.

MISO had to address transmission service provided under approximately 232 existing long-term grandfathered contracts. In a series of orders based on the results of a fact-finding process, FERC ordered MISO to carve out certain grandfathered agreements and approved MISO's proposed options for the treatment of other GFAs for at least a transition period ending February 1.

The plan adopted in 2004 respected the contract rights of parties to grandfathered transmission agreements while allowing MISO to begin operation of its energy markets on schedule.

PJM Interconnection is ready to file revised specifications for financial transmission rights

Several weeks after the Federal Energy Regulatory Commission rejected the PJM Interconnection's proposal to increase credit requirements for financial transmission rights market players, the regional transmission organization is ready to file a refined proposal that it hopes will better reflect potential risk exposure, documents show.

Following the credit default of Exel Power Sources in late October, PJM and its members plan to increase collateral requirements for FTRs.

Exel is a Delaware-registered limited liability company, with its place of business in Newark, Delaware. It is run by Kawaliya Kalibala, who said in an interview he had no previous experience in electricity markets.

FERC granted the company market-based rate authority September 27, after it defaulted on a margin call for additional collateral. FERC did not return calls on the subject of Exel and Kalibala by press time.

If approved by FERC, the collateral requirement for FTRs would be path-specific and would also reflect month-to-month congestion volatility more accurately.

According to the proposal, PJM would evaluate collateral for each of the transmission paths based on historical averages from the last three years. The new requirement would calculate the exposure of the market participant based on current congestion and would allow PJM to ask for additional credit security as soon as congestion increases.

The cost of the credit default would be aggregated among the members based on their market activity in the last 30 days. The majority of the cost, ranging from $3.9 million to $4.37 million, would be included in members' December bills, so they can include the expense in their 2007 financial statements, Suzanne Daugherty, PJM CFO and treasurer, said.

At this point, Exel has not indicated any intention to file for bankruptcy, but has authorized PJM to try to sell its open transmission positions. PJM has not been able to find a member to buy the transmission rights.

At a November 15 meeting, PJM asked all of its members for help to convince FERC to authorize higher collateral charges. Traditionally, the commission has viewed the higher charges as a barrier to market entry. "Now that we have evidence that defaults are possible, we can prove our theory," Stu Bresler, executive director of market operations, said.

Meanwhile, PJM members on November 15 approved the implementation of a three-year FTR auction.

If approved by FERC, auctions would start in the summer of 2008 after an auction of June through May annual FTRs is conducted in May, PJM said.

The extra auction round would offer transmission rights for the three years starting 2009 and ending 2011. The 2008-2009 annual FTRs to be offered at the annual auction would not be included in the three-year round.

PJM would offer peak, off-peak and around-the-clock FTR products. However, the RTO would not offer option FTR products at the long-term auction that are available at existing monthly, quarterly and annual auctions.

According to the proposal, FTRs acquired in the long-term auction may have terms of one year, for each of the planning years covered by the auction, or a term of three years.

The revenue from the three-year rights would be allocated at the end of each year.

The required collateral for the long-term auction would be calculated based on historical values, similar to its other auctions. If a participant is declared in default of long-term FTRs, PJM would liquidate the participant's positions at the next auction.

Buyers and sellers agree: NYISO's proposal for a state forward capacity market falls short

In the fight over the New York City capacity market, the latest proposal from the New York Independent System Operator has drawn very strong skepticism from both sides of the dispute.

In federal regulatory filings on November 19, power suppliers expressed a willingness to accept a revamped market with a new system of mitigating market power for both sellers and buyers of power, but they argued that the New York ISO proposal will not get the job done. On the other side, buyers and state and city officials bluntly opposed the attempt to mitigate buyers' market power.

There was one point of agreement from opposite sides of the divide: New York City needs a forward capacity market, according to independent generators and Consolidated Edison of New York. The existing capacity market is month by month.

The Federal Energy Regulatory Commission on July 6 ordered NYISO to submit a plan for reforming the in-city installed capacity market, and the grid operator submitted its proposal on October 4.

NYISO proposed that it would establish a monthly reference price determined by its demand curve for the capacity market and by the assumption that all qualified capacity would clear the market. All mitigated generators, the entities that own more than 500 MW of capacity, would be required to offer their capacity at or below the reference price. The ISO also proposed that a floor price set at 75% of the net cost of new entry be set for new facilities, with significant exemptions.

The Independent Power Producers of New York on November 19 filed at FERC to say it "applauds the NYISO's attempt to develop a balanced mitigation approach that addresses market power that may be exercised by either sellers or buyers in New York City." But the proposal would exempt existing generation from the floor while not exempting existing generation from the reference price limit, IPPNY noted. It also would allow other exemptions, and the result would be a market clearing price that would fluctuate somewhere between 50% and 76% of the net cost of new entry, according to several filings by generators.

The exemptions "will destroy the ICAP market," said Entergy and Mirant in a joint filing.

By contrast, Con Ed, the dominant buyer of power in the city, said no mitigation of buyers' market power is needed. Joining Con Ed in opposing that element of the NYISO proposal were New York City officials, the New York State Consumer Protection Board, the New York Power Authority, the Long Island Power Authority and a coalition of commercial power buyers (Docket No. EL07-39).

LIPA said NYISO had come up with a "draconian" plan on how to prevent buyers' market power, or monopsony. Con Ed said, "Monopsony power does not and cannot exist in the NYISO's current and proposed market structure." And a New York City filing argued that "there is no relationship between two analytically distinct markets," suggesting the capacity auction market is unaffected by the long-term power and capacity arrangements developed by load-serving entities.

The "buyer-side" filings also advocated refunds for the overcharges alleged by those officials and utilities. They claimed that generators manipulated the in-city capacity market to overcharge load servers during 2006 and 2007.

Demand response, interruptible contracts help ISOs meet peak demand, says NERC

Demand response and interruptible contracts for power supplies are having a larger impact on grid operations and making it easier for utilities and independent system operators to meet peak demand, the North American Electric Reliability Corp. said last week in its winter reliability assessment.

Although most of the US reaches peak demand levels during summer months, parts of the Northwest and many regions in Canada do so during the winter, and NERC's 2007 winter reliability assessment finds ample resources available to meet peak demands.

Becoming more apparent, as evidenced in the latest assessment, however, are the benefits from demand response, even as NERC grapples with how to define demand response resources, officials said in an interview this week.

Demand-side resources are projected to increase by 2,100 MW, or 12%, this winter, compared with last winter, with significant gains in New England and the Canadian Maritimes region, said David Nevius, NERC senior vice president.

The penetration of demand-side resources in the Northeast Power Coordinating Council footprint, which stretches from New York into Nova Scotia, New Brunswick and Quebec, is due to the upcoming implementation of a forward capacity market by the New England ISO and the extended outage of New Brunswick Power's Point Lepreau nuclear power plant, Nevius said. The 680-MW plant is expected to be shut down in April for an 18-month refurbishment, added Mark Lauby, manager of reliability assessments at NERC.

Across all of North America, demand-response resources are expected to grow to 20,000 MW, from 17,900 MW last winter, Nevius said. "We didn't see as much of an increase in the summer assessment" done earlier this year, he said. Data for the winter assessment is collected in August and September, and the New England developments had the biggest impact, with demand-side resources in the NPCC footprint growing 63.5% compared with the previous winter, he said.

The New England ISO is starting to see demand response providers register for its forward capacity market and the industry is starting to view demand-side resources as being on a level similar to generation resources, Lauby said. "My view, based on trends, is this is going to increase over time" and will be beneficial for grid reliability, he said.

Nevius cautioned, however, that the growth in demand response is not a solution to the significant investment needed in generation and transmission to meet growing demand and to replace aging infrastructure. "If you can reduce demand, great, but the network still needs to be refurbished," he said.

Although regional capacity margins are projected to decline and winter peak demand is projected to grow by more than 2% over last winter's projection — reaching 721,783 MW in January 2008 NERC-wide — every region is reporting sufficient resources, with natural gas and coal supplies projected to be very strong over the winter months, NERC said.

"While our recent long-term outlook showed we have a long way to go before we can confidently say we have secured a reliable and adequate long-term future for electricity, our winter outlook shows that the industry is rising to meet short-term needs," NERC President and CEO Rick Sergel said in a prepared statement.

Florida has the largest penetration of demand-side resources being used to meet demand, with more than 3,500 MW spread out among different programs, Lauby said. Among the different

NERC regions, demand response accounts for less than 3% of peak demand in most regions, while it is more than 7% in Florida because of large utility-driven programs for residential customers, he said.

There are many different labels and terms thrown around for different demand-response services, and quantifying such resources is becoming more important for reliability. Efforts are under way by a NERC task force, the North American Energy Standards Board and the US Demand Response Coordinating Committee.

The NERC task force is taking stock of how demand-side resources are counted and trying to reach a consensus. Currently, NERC defines such resources as direct control load management or interruptible demand based on contractual arrangements between retail customers and grid operators, but it is taking comments on possible changes and it may issue a report on the subject in December, Lauby said.

Lafayette, Louisiana muni seeks investigation of SPP's role as independent grid co-ordinator

The Lafayette Utilities System in Louisiana wants federal regulators to examine the performance of the Southwest Power Pool as the independent coordinator of transmission for Entergy companies. In a few important ways, Lafayette says, SPP is not performing the job as it should, and the reason could be insufficient resources.

The municipal utility is concerned, as is Occidental Chemical, that SPP's third quarterly report on its function as Entergy's ICT shows a continuing and worrisome increase in "transmission loading relief" events.

In comments to the Federal Energy Regulatory Commission, Occidental recalled that it commended SPP in August for identifying and working on the TLR problem in the second status report, but the industrial company said FERC must "take immediate action to determine the cause" and solution (Docket No. ER05-1065).

SPP's ICT report to FERC attributes the growing incidence of TLRs to record-high temperatures and record peak loads during the June-August period, but Lafayette and Occidental think the explanation is lacking. According to Occidental, "habitual TLR events are indicative of fundamental problems in a transmission system." And Lafayette said the fact that overloads were largely focused on one flowgate "suggests that factors other than regional weather conditions are involved."

According to Lafayette, the ICT's records show a 320% increase in serious TLRs over the same three months in 2006 — from five in the 2006 period to 21 this year — and a 491% rise in the number of firm megawatt-hours curtailed — from 7,086 to 41,905.

Lafayette also criticized a higher number of transmission service requests remaining in the "study" mode, and what it called lack of leadership in regional transmission planning.

But the muni thinks the problems indicate "a lack of ICT resources rather than ill intent." It says "SPP may have greatly underestimated the resources required for the ICT staff to perform their assigned tasks in a timely and effective way." Still, Lafayette said, customers "should not suffer the penalty for SPP's miscalculation." Thus FERC should have a conference, the muni said, to allow stakeholders and the ICT to present more information about the ICT's performance and to discuss whether and how more resources are needed.

FORECASTS

Global wind power set to triple by 2015, to 290 GW from 91 GW, says analyst

The amount of wind power in the world is set to triple to 290 GW by year-end 2015, from 91 GW at year-end 2007, according to a recently released report from Cambridge, Massachusetts-based consulting company Emerging Energy Research.

"The US and China will be neck-and-neck for global annual MW-added leadership in the coming decade," according to Joshua Magee, senior analyst at EER.

"US federal renewable energy policy support and proactive transmission expansion projects will need to stay on pace for the country to remain ahead of China's voracious renewables growth appetite by 2015," said Magee.

China is poised to continue record wind installations in 2007, said Magee, and could surpass its goal of installing 5 GW by as early as 2009, with massive industrial supply chain investments.

In addition to the regulatory boost from the US federal production tax credit and strengthening state renewable portfolio standards, Canada is also set for a wind power boom in the coming years, largely as a result of demand driven by renewable power solicitations, particularly in Ontario and Quebec, said Magee.

Meanwhile, Europe will continue as the world's largest regional market in terms of annual growth while transitioning from established markets such as Spain and Germany to new long-term growth regions such as the UK, France, Portugal and Italy, said EER. Magee also forecast that there would be "significant wind expansion" in Eastern European markets as well. He said that Poland and Turkey are poised to average more than 500 MW annually between now and 2015.

Strong demand in the past several years has resulted in rising construction and equipment costs, but Magee said "virtually every major wind turbine supplier is increasing its production capacity." New fabrication and assembly facilities are planned in North America, Europe, the Asia Pacific region and South America, and numerous component suppliers are investing in key wind turbine supply chain "pinch points" such as gearboxes, blades, bearings, towers and castings, according to EER.

Fossil fuel price volatility is likely to continue to stimulate long-term demand, said Magee, with wind serving as a quickly deployable hedge against natural gas and petroleum power generation.

Pace analyst warns that gas price volatility will increase if gas replaces coal in new plants

If utilities build natural gas-fired power plants to make up for the pull-back from new coal-fired power plants, it could increase demand for natural gas and result in more price volatility for the fuel, according to Christopher Berendt, director of environmental markets and policy at the Pace consulting group.

In testimony before the Senate Committee on Environment and Public Works on November 15, Berendt said: "Our clients increasingly advise us that they cannot build any coal plants, no matter how clean the technology, and that the only generation options in the near-term are renewables and natural gas."

While renewables will be important in diversifying the US generation portfolio, they cannot meet the 120,000 MW of incremental generation capacity needed over the next 10 years alone, said the consultant.

He added that nuclear generation is also unlikely to fill the gap in that timeframe. "There is no clear roadmap for increased nuclear generation," he said.

If gas is called on to fill the gap left by coal, Berendt estimated that the US would require about 6% more gas than Pace's current projections for 2017 call for, and that rise in gas demand could increase imports of liquefied natural gas by 33% and expose the economy to greater natural gas price volatility.

RENEWABLE ENERGY

Midwestern states, Manitoba present plan for CO2 cap-and-trade, renewables goals

A group of Midwestern states and the province of Manitoba plan to attack climate change by adopting sweeping changes that affect utilities and independent generators, including a cap-and-trade program for carbon dioxide, a 30% renewable energy goal and a 2% annual cut in energy use.

The Midwestern Governors Association outlined its plans in two pacts signed last week, one dealing with the cap-and-trade program and one with a broader energy strategy, the Energy Security and Climate Stewardship Platform. The pacts call for major shifts in a region that depends on coal for 71% of its generating needs, compared with 49% for the national average.

In a move with national implications, Illinois, Iowa, Kansas, Manitoba, Michigan, Minnesota and Wisconsin will form a multi-sector, greenhouse gas cap-and-trade program, with Indiana, Ohio and South Dakota acting as observers in the program. The states and Manitoba plan to develop rules for the program and set carbon reduction goals within a year, according to the Midwestern Greenhouse Gas Accord. Reduction levels will be in the 60% to 80% range, Wisconsin Governor Jim Doyle, a Democrat, said last week.

Under the plan, the Midwest would see major changes in the way it burns coal at its power plants. The states and Manitoba will not allow new coal-fired power plants to be built after 2020 without carbon capture and sequestration equipment on the plant. Existing coal-fired plants will all use CCS technology by 2050, according to the pact.

The states and Manitoba will work together to develop new regulations to ship carbon across state borders with an interstate pipeline slated to be operating by 2012 for enhanced oil recovery. The pact also calls for the Midwest to have at least five operating integrated gasification combined-cycle plants by 2015, and it calls on ensuring cost recovery for utilities that want to build "advanced technology" coal plants with CCS technology. "States should also consider a comparable process for merchant and independent power producers involved in request for proposal bidding processes," the pact said.

The GHG cap-and-trade program was spurred in part by the failure so far of the federal government to develop a national climate change strategy. Doyle envisions the Midwestern system allowing for credit trading between other regional systems like the Regional Greenhouse Gas Initiative in the Northeast and the Western Climate Initiative, which is being developed in the West. The Midwest program was developed with input from utilities, environmental groups and others.

Nebraska and North Dakota joined the other states and Manitoba in signing the broader energy pact, which includes a pledge to ramp up the Midwest region's use of renewable energy to 20% by 2020, 25% by 2025 and 30% by 2030. To meet the goals, the governors called on expanded regional transmission planning and suggested that state regulatory commissions could expand the definition of "public benefit" to include regional benefits.

National Grid says it has insufficient RECs to meet its 2007 Rhode Island requirements

National Grid told Rhode Island regulators last week that it has been unable to secure enough renewable energy certificates, or RECs, to meet its 2007 requirement.

The shortage is in keeping with reports from neighboring Massachusetts, where utilities have been forced to make alternative compliance payments, a de facto state penalty charge, for coming up short. RECs are scarce and prices are high because little large-scale renewable energy has been developed in southern New England to date, partly because of opposition to wind farms.

Rhode Island's portfolio standard requires that 3% of the power sold to consumers come from renewables for 2007, a standard that rises to 3.5% next year.

In testimony before the state Public Utilities Commission, National Grid said it plans to go out to bid again to see if it can secure the certificates needed for 2007. Should the utility continue to come up short, it will make the $57.12/MWh alternative payment to the state.

The utility first sought the certificates as part of its solicitation for last resort power in February and August. However, suppliers offered prices that National Grid said appeared to be above market.

The utility also issued two stand-alone solicitations in April and October, and purchased 422,700 RECs at a total cost of $8.5 million. Roughly 220,000 of those RECs can be applied to the utility's 2007 requirement. The remainder are for the 2008 and 2009 requirements. Each REC is worth 1 MWh.

It is not yet clear how many certificates short the utility is for 2007. National Grid will not know its final obligation for 2007 until next month when it reconciles its load figures for the year. The utility has until June 15, 2008, to finish making its 2007 REC purchases.

National Grid plans to conduct an auction in the spring to try to secure remaining RECs it needs for 2007, as well as a portion of its requirement for 2008 and 2009. The utility estimates it will need more than 256,000 RECs for 2008 compliance alone.

Wind developers have been urging the utility to make long-term REC purchases. This gives the developers predictable revenue and helps them secure financing. A working group that includes the utility, wind developers, state agencies and environmental organizations, is trying to reach a consensus on the idea. The long-term REC contracts would likely begin in 2010, National Grid said.

REGULATION & LEGISLATION

Naysayers on Lieberman-Warner emissions bill call for economic analysis before December vote

Opponents to mandates to cut industry greenhouse gas emissions last week called for a thorough economic analysis of legislation prior to action by the Senate Environment and Public Works Committee, but key members indicated that the December 5 vote would proceed as scheduled, with or without the requested study.

Following the third committee hearing on America's Climate Security Act, Senator Joe Lieberman, the Independent Democrat from Connecticut who with Virginia Republican John Warner crafted the market-based bill to cap GHG emissions, said he saw "no potential delay" in markup.

"It is very important that we go forward, and I believe Senator [Barbara] Boxer feels the same way," said Lieberman.

Lieberman and Warner earlier this week requested that the Environmental Protection Agency and the Energy Information Administration conduct an economic analysis of their bill. But chances that that analysis would be available by markup were uncertain.

Lieberman said existing analysis by the federal agencies on the first GHG cap-and-emissions trading bill he offered with Republican John McCain and various private analyses might have to do in the meantime. Should the bill win committee approval, the full Senate may not take it up until February when the EPA/EIA analysis could be ready, he said.

Boxer, a California Democrat who chairs the committee, countered her Republican colleagues' request for more time to debate the bill by noting the numerous hearings since January on climate change in addition to three hearings devoted to the bill, S. 2191, that cleared Lieberman's subcommittee 4-3 on November 1. The bill is the first mandate on GHG emissions to clear a congressional body.

Briefings would be held at any members' request, Boxer told the panel, and the markup could go through to December 6 to accommodate the quantity of amendments.

"This is the moment, and we're poised to do landmark legislation. We have a window here to act," she said. "I am convinced we can and must act."

Still, Republican members, excluding Warner, argued that more time was necessary to digest the bill, which seeks to reduce GHG emissions from the electric power, the transportation fuels and the industrial sectors by 70% below 2005 levels by 2050.

The measure creates an emission allowance market where these sectors would be awarded a certain percentage of permits to emit but then would have reduce their emissions or buy more permits in an open auction. Emission offset projects as well as banking or borrowing of these emission allowances are authorized under the bill.

Senator Jim Inhofe, the committee's top Republican and ardent climate change skeptic, also suggested that a tax on carbon dioxide would be a "more honest" way to go than an emissions cap-and-trade program. Boxer responded that Congress would be unlikely to impose such a tax and that an open market is the best way to determine a price on CO2.

With a nod toward the scores of amendments Inhofe has in the works, Boxer quipped, "It will be a very interesting switch; you supporting a tax and me supporting a free market."

Environmental groups urged that committee to move forward on the cap-and-trade bill while witnesses from industry and Wall Street consultants said the measure could result in high costs for electricity and lead to other economic harm.

"While markets tend to be efficient distribution and pricing mechanisms for commerce, they also possess characteristic that can inject unanticipated volatility into regulation, particularly when the governance structure encourages noncommercial traders to enter the market to provide necessary liquidity," said Kevin Book, energy policy senior vice president at FBR Capital Markets.

Fred Krupp, president of Environmental Defense, told the lawmakers that further delay in capping GHG emissions would force power prices to escalate higher. A two-year delay would require steeper cuts to achieve the same environmental benefits by 2020 under Lieberman-Warner, he said.

"The stakes of us acting in this Congress are enormous," said Krupp.

Under questioning by Inhofe, who plans to support amendments to support greater development of nuclear, a non-GHG-emitting power source, Krupp said that there were concerns about the security and waste disposal for nuclear power plants. But he said the option should not be ruled out and he would support increased funding by Congress to address these problems.

"I don't think any low-carbon option should be taken off the table," Krupp said.

A preliminary analysis provided to bill proponents by the Clean Air Task Force, an environmental advocate, said that the Lieberman-Warner bill as approved by the subcommittee would cost the typical residential electricity customer \$76 a month in 2030 as compared to \$81 a month as projected by the EIA. The task force also said energy efficiency developments and safety nets devised for consumers under the bill would protect middle and low-income consumers.

But senators in coal-dependent states took note of comments from Duke Energy that the bill would result in a tax on electricity consumers in 25 states. In a news release distributed at the hearing, Duke Energy Chairman President and CEO Jim Rogers said that requiring electric utilities to buy allowances for existing coal-fired units "is nothing more than a carbon tax."

Allowance prices could run as high as \$45/ton of CO2, resulting in a 53% hike in customer power bills when the legislation takes effect in 2012, according to Duke Energy. An original member of US Climate Action Plan — the multi-billion industry and environmental group calling for GHG mandates — Rogers said Duke Energy could have to buy between 44 and 57% of its emission allowances to meet Lieberman-Warner requirements in 2012.

"The science is clear that we must move ahead and act quickly," said Rogers. "But the legislation must not pit one region against another and create regional winners and losers in our nation's economy."

Meanwhile, at a conference in London this week, Energy Secretary Samuel Bodman sought to reassure business leaders that a provision in the Lieberman-Warner bill to force China, India and other countries to reduce their GHG emissions by imposing certain trade conditions on them would not "create divisive trade wars."

The provision is designed to ensure that the US would not be economically disadvantaged if it caps its GHG emissions and its major trading partners do not. Specifically, the provision would require countries without "comparable" GHG caps to purchase "credits" to "offset" the emissions that they create when manufacturing certain products that they want to export to the US. The provision is designed to "encourage effective international action" on global warming, and to ensure that "greenhouse gas emissions occurring outside the United States do not undermine the objectives of the United States in addressing global climate change," the bill states.

Bodman said that any scheme to reduce GHG emissions must be "internationally accepted" and based on "free trade." And that will require establishing a "rules-based framework that all countries must abide by, including those in the developing world."

Lawmakers may have to choose between putting RPS or CAFE standards in energy bill

House of Representatives and Senate leadership may be forced to choose between introducing a final comprehensive energy bill that boosts the fuel efficiency mandate for cars and light trucks, or one that requires electric utilities to derive some of their power from renewable sources, Representative Mark Udall told reporters this week.

"I think they're equally important," the Colorado Democrat said, adding that if plug-in automobiles increase in popularity in the future, utilities will account for a larger chunk of the transportation sector's energy use and carbon emissions.

Udall is an advocate for the House bill's renewable portfolio standard language, which would require private utilities to source 15% of their power supply from renewable generation.

Staff of House Speaker Nancy Pelosi, a California Democrat, said that no decision had been made on whether to include the RPS in the final energy bill or to remove it.

House Energy and Air Quality Committee Chairman Rick Boucher, a Virginia Democrat, also told reporters earlier this week that key components of the energy legislation have not been resolved and such resolutions would be a "leadership call."

However, Udall seems slightly pessimistic about the item's prospects for inclusion in the final bill, H.R. 3221, which is likely to be considered by the House and Senate in December.

Udall said there was strong support for the item in both chambers of Congress, and he is still lobbying for it. A meeting with Pelosi scheduled for November 21 was cancelled, but will be rescheduled, he said.

Senate Majority Leader Harry Reid of Nevada said November 6 that the 60 votes needed for the Senate bill's, H.R. 6, corporate average fuel efficiency standard to clear that chamber are not the same 60 that would support the RPS.

The CAFE language has some Southeastern supporters that might feel an RPS unfairly penalizes their region because they say they have more limited renewable resources.

Democratic leaders have tended to highlight the CAFE item as a priority, since it would be the first such increase in 30 years. Sixty votes are necessary to avoid a filibuster in the Senate, which would prevent Congress from sending a final bill to President Bush.

NERC and FERC rule on QFs seeking exemptions to ERO reliability standards

Two small power generators in Florida will have to comply with reliability standards but two others will not, according to rulings this week by reliability regulators.

The Federal Energy Regulatory Commission on November 15 said that two waste-to-energy plants, owned by Lee County in one case and the Solid Waste Authority of Palm Beach County in the other, would have to register with the North American Electric Reliability Corp. and comply with NERC's regulations.

The two were among several qualifying facilities under the Public Utility Regulatory Policies Act that had protested registration.

Earlier this fall, FERC had judged that two other QFs may not meet the criteria for registration, and it sent the two cases back to NERC for reassessment (*GPR*, 25 Oct, 26). On November 14, NERC ruled that the two, Mosaic Fertilizer and the city of Tampa, were too small to affect the grid enough to require registration (Docket Nos. RC07-1, -2). NERC told FERC on November 14 that it had obtained more information on the matter from the Florida Reliability Coordinating Council, which according to NERC said the small producers could be exempt from the registry. NERC endorsed the Florida decision.

In its filing to FERC, NERC said the Florida council determined that "it is acceptable for entities with units connected at 69 kV that do not have both a greater than 20 [megavolt ampere] gross nameplate rating and greater than 20 MW of firm power sales to be exempt from the compliance registry for peninsular Florida under current conditions." Mosaic and Tampa fit those conditions. But bigger units that sell more should be included, the council said.

In the cases FERC decided November 15, it said the municipal waste plants in Lee and Palm Beach counties should be registered. The plants are larger than 20 MW, which is one of NERC's criteria for registration, and they are interconnected to 138-kV transmission lines. The voltage threshold for registration is 100 kV, FERC said in its decision (Docket Nos. RC07-3, -5).

Compliance with NERC standards often requires expenditures that owners would not otherwise have to make, and several small companies have challenged the reliability organization's designations.

House bill would cap GHG emissions at 75% of current levels by 2050

A newly introduced bill that would cap greenhouse gas emissions at 75% of current levels by 2050 will be the House companion bill to the Lieberman-Warner bill moving through the Senate now.

Introduced by Representatives Wayne Gilchrest, a Maryland Republican, and John Olver, a Massachusetts Democrat, H.R. 4226 would use the successful approach of the Clean Air Act to provide market incentives for new low-carbon technologies in the US and protect the competitiveness of US manufacturers through international negotiations, Gilchrest said in a statement. If those tactics fail, the bill would allow a charge to importers for the GHG their products created when they were manufactured overseas.

"This bill addresses the 800-pound gorillas in the room, India and China," said Olver. CO2 emissions in those countries "are predicted to double by 2030. This would be an increase of about 50% of the current global emissions." This bill would ensure "that foreign manufacturers do not have a competitive advantage over environmentally responsible US manufacturers here at home."

Senator Barbara Boxer, a California Democrat, is pushing the Lieberman-Warner bill, S. 2191, toward a vote in the Senate Environment and Public Works Committee by early December (*see story, page twenty six*).

More than 50 pieces of introduced legislation in the Congress address global warming, climate change, reduction of greenhouse gases or some similar topic.

NARUC chooses Analysis Group to study best practices for competitive procurement

The National Association of Regulatory Utility Commissioners has selected consulting firm Analysis Group to review competitive power procurement issues and deliver a report to state regulators in February, said Susan Tierney, managing principal at the Analysis Group.

Analysis Group was chosen to conduct the study and identify best practices for utility power procurements after NARUC issued a request for proposals in late September, Tierney said last week at NARUC's annual meeting in Anaheim, California. The study should identify how procurement results are evaluated under different regulatory structures, examine state policies, develop criteria for determining model practices and come up with a range of model practices based on the criteria, NARUC said in its RFP.

NARUC and the Federal Energy Regulatory Commission have been engaged in a "collaborative dialogue" on competitive power procurement, and NARUC has tried to see if federal agencies would be willing to help pay some of the $150,000 it intends to pay for the study, officials said last month.

NARUC was "asking for proposals for how a consultant would conduct a survey of what's going on in the states with regard to competitive procurement," Tierney said. She noted that consultants responding to the NARUC RFP "had to essentially promise that they would come back with a report in February that summarized what are the experiences. It's not designed to be a comprehensive listing of every state. It's meant to be illustrative of the practices across the states, across the regions, different kinds of markets, et cetera. And then describing in more detail some of the best practices" for various types of procurement, she pointed out.

"The idea will be to look at both the structure of these competitive procurements, as well as the processes that they use," Tierney said in a presentation at the convention. "It was very clear to us" that NARUC is not looking for "somebody to evaluate whether a particular state's approach is deficient, or whether a particular state's approach is competitive or not." Rather, the goal is to "pick and choose from the best ideas that are out there for soliciting projects and coming up with results that states have found to be just and reasonable," Tierney said.

FERC releases report detailing actions taken by its Office of Enforcement

The Office of Enforcement at the Federal Energy Regulatory Commission has taken action on 64 investigations since October 2005, after its enforcement authority was greatly expanded, the agency reported on November 14.

FERC closed 47 of those cases without taking any action, and in 25 instances because there was insufficient evidence of a violation and in 22 instances because it found a violation but decided not to issue a sanction.

Among the 17 other cases, 15 resulted in settlement involving the payment of civil penalties or other monetary remedies, the filing of compliance plans and other remedial steps. Two cases resulted in "show cause" orders that remain pending before the commission.

Since January, the report said, FERC has issued 12 orders approving stipulations and agreements between commission staff and companies to resolve violations. In most cases the company admitted the violations as part of the settlement.

All 12 settlements resulted in the payment of civil penalties, and some also involved disgorgement or other monetary remedies. The sanctions ranged from $300,000 to $10 million.

Those were among the details released in a "Report on Enforcement" that provides an overview of FERC enforcement since the Energy Policy Act of 2005 gave the agency far greater power to penalize market participants for such behavior as market manipulation or other failures to follow agency rules. Since enactment of that law, the commission has expanded its enforcement staff, codified market behavior rules and strengthened its prohibitions on energy market manipulation.

The report is available on the FERC web site at www.ferc.gov.

Meanwhile, a coalition of energy trade associations last week released a white paper calling on FERC to improve energy regulation enforcement through "greater clarity in its policies, rules and processes."

"Market participants who desire to take the steps necessary to achieve full compliance need assistance from the commission to develop a better compliance 'road map,'" said attorney Bill Massey in a news release. Massey, a former FERC commissioner, is representing the coalition.

The coalition's recommendations include clarifying, simplifying and codifying certain commission policies and rules to reduce uncertainty; measuring enforcement success by the degree of compliance rather than the number and amount of penalties; and providing timely responses to requests for assistance in interpreting regulations.

NARUC approves resolution recommending principles for climate change legislation

The National Association of Regulatory Utility Commissioners last week approved a resolution spelling out recommended principles for US climate change legislation.

The resolution was amended to add language calling for evaluation of market mechanisms other than a cap-and-trade approach, including a carbon tax. NARUC was having their annual meeting in Anaheim, California.

Outgoing NARUC President Jim Kerr of North Carolina said in a statement that the new policies position the group to be “a major player as Congress takes up climate legislation and ensures that our views, and the views of constituent ratepayers, will be heard.”

The resolution recommends that if Congress implements a cap-and-trade program, allocating allowances to the electricity sector — before auction-only availability of the allowances kicks in later years — is an “appropriate transitional measure” to minimize economic impact and be given to regulated utilities serving as local distribution companies.

The resolution also recommends that any allocation program being devised should “not create a windfall for particular regions,” regulated utilities or generators, and should ensure that customers receive the benefit of allocated allowances.

In addition, the resolution advocates that cost-containment mechanisms should be included in a cap-and-trade system to minimize “abrupt changes in the cost of compliance,” which could hurt electricity consumers or allowance markets. Such measures should be designed to achieve environmental benefits while ensuring price stability and predictability, promoting investment in appropriate technologies and minimize price volatility.

John Shelk, president of the Electric Power Supply Association, said EPSA was satisfied that the resolution had been modified in a way that ensured the policies would be “competition neutral.”

But Jan Smutny-Jones, executive director of California-based Independent Energy Producers Association, had a different view. The problem is that regulated utilities may “use [GHG emissions] allocations in a way that discriminates against competitors,” Smutny-Jones said. Utilities in California want to get back into the generation business, thus independent generators can be viewed as competitors, he said.

This is troubling because climate change problems likely “won’t get fixed” without independent power producers, Smutny-Jones said. If you look at the last 25 years, it is IPPs who are largely responsible for increased use of combined heat and power, combined-cycle turbines and renewable resources.

Smutny-Jones said IEP agrees with the notion that revenue from cap-and-trade should be spent on activities to reduce GHG emissions. But the “right solution is not necessarily giving money to utilities,” he said.

NARUC adopted a second resolution as well, which recommended strategies to deal with a carbon-constrained world. Strategies in the broadly worded resolution include a call for increasing reliance on low or no-carbon resources, such as energy efficiency, high efficiency combined heat and power and demand response.

Conn. Light & Power wants merchants’ finances scrutinized under peaker program

Merchant generators should face utility-style scrutiny from regulators if they are to receive utility-style cost recovery under a new Connecticut program to encourage more peaking plants, said the state’s largest utility.

Connecticut Light & Power argued for the deeper investigation into merchant finances in a brief filed last week before the state Department of Public Utility Control.

The state agency is exploring how to put into effect a new state law that gives merchant generators a guaranteed return on peaking projects. The law also places utilities in the restructured state back into the generation business for the purpose of building peaking units. As part of the law, legislators took the unusual step of giving winning merchant generators cost-of-service terms so that regulated utilities would not have a competitive edge.

But now CL&P says generators must also undergo the same kind of electric retail rate review: “The department must regulate the peaking generation unit and have access to books and records as though the non-utility generator is a public service company.”

A merchant generator’s willingness to undergo an annual retail rate case should be a condition for approval of bids, CL&P said.

Merchant generators see it differently. Bridgeport Energy called CL&P’s proposal “unfair and unnecessary,” arguing that competitive companies would face the “statutory burdens” of utilities without the benefits, since merchant generators cannot directly bill customers.

FirstLight Power Resources also argued against requiring merchants to open their financing to public scrutiny. Instead, they should be required only to reveal natural gas and electric interconnection costs. Other project costs, such as land, equipment and labor, should remain proprietary, FirstLight said.

Merchant generators also argued that Connecticut utilities should be required to sign power purchase contracts with any merchant peaking projects that win bids, an approach that would create assurance for investors.

CL&P, however, says there is “no need” for utilities to sign contracts with winning merchant projects. The projects can bid into the regional market, and any revenue received through the market should offset cost recovery.

The state’s other electric utility, United Illuminating, has taken the unusual tack of teaming up with a generation company, NRG Energy, to bid its peaking units (*GPR*, 25 Oct, 1).

State lawmakers set up the new rules because they were concerned that the state lacks enough peaking power, a problem that could drive up Connecticut’s already high rates and jeopardize reliability.

Bids for the peakers are due to state regulators by February 1.