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Climate change concerns prompt Florida munis to suspend plans for 800-MW, coal-fired Taylor Energy Center

by Andrew Engblom

For the second time in less than a month, a proposal for a coal-fired power plant in Florida appears dead; this time, it is the 800-MW Taylor Energy Center, which had been proposed by a group of municipal utilities to meet their baseload demands.

The utilities — the Florida Municipal Power Agency, JEA, the city of Tallahassee and the Reedy Creek Improvement District — said July 3 they are suspending their permitting efforts due to growing concerns about greenhouse gas emissions.

"Our mission is to provide reliable power at an affordable price in an environmentally responsible manner. We believe the state-of-the-art technology we proposed would satisfy those objectives; however, growing concerns about climate change have raised questions that must be addressed thoughtfully," Taylor Project Manager Mike Lawson said in a statement announcing the decision. "It's more important that we work with state leaders to craft an energy plan for Florida."

He added that the suspension will "allow the utilities time to assess how to best meet their needs in ways consistent with growing concerns about greenhouse gas emissions," noting that a final decision must be confirmed by the governing boards of the four municipal electric utilities.

Continued on p 15

In this Issue

Click on headline to advance story

AMP-Ohio joins partnership group for Peabody's Prairie State power project

by Mike Niven

Peabody Energy Corp. announced July 2 that American Municipal Power Ohio has become the latest partner in its planned Prairie State Energy Campus coal-fired project in Washington County, Ill.

AMP-Ohio, which serves more than 520,000 customers through member utilities in Ohio, Pennsylvania, West Virginia, Virginia and Michigan, has committed to take 300 MW of the plant's 1,600-MW capacity, Peabody said. Peabody has now secured commitments for approximately 1,300 MW of Prairie State's capacity. Other partners in the project include the Illinois Municipal Electric Agency, Indiana Municipal Power Agency, Kentucky Municipal Power Agency, Missouri Joint Municipal Electric Utility Commission, Northern Illinois Municipal Power Agency and Prairie Power Inc.

"We've provided reliable, affordable electric power to our customers for more than three decades," said AMP-Ohio President and CEO Marc Gerken. "Participating in Prairie State is core to our strategy of securing a clean, low-cost, long-term supply of electricity to serve our 121 member communities."

Continued on p 15

East Kentucky Power to invest $656 million in air controls to end NSR litigation

by Wayne Barber

East Kentucky Power Cooperative Inc. has agreed to invest $656 million in new air pollution controls at its coal-fired power plants in settling a lawsuit brought by the federal government charging that the utility violated the New Source Review standards of the Clean Air Act.

East Kentucky Power, the U.S. Justice Department and the U.S. Environmental Protection Agency announced the agreement July 2. The deal culminates nearly three years of negotiations between the federal government and the utility.

Summer Holiday

SNL Generation Markets Week will not publish Tuesday, July 17.
Your next issue will be dated Tuesday, July 24.

The settlement is contained in a proposed consent decree filed in the U.S. District Court for the Eastern District of Kentucky. The proposed agreement is subject to a 30-day public comment period.

The settlement calls for East Kentucky Power to pay a $750,000 fine. The cooperative does not admit any violation of the Clean Air Act.

The utility will install pollution control equipment to reduce emissions of pollutants that cause acid rain and smog by more than 60,000 tons per year, according to an EPA/Justice Department press release.

These actions will reduce annual emissions of smog-forming nitrogen oxides by approximately 8,000 tons and sulfur dioxide by more than 54,000 tons per year from its H.L. Spurlock, Dale and J. Sherman Cooper plants when the controls are fully implemented. By installing these pollution control measures, the plants will emit 50% less NOx and 75% less SO2 as compared to 2005 operations.

"We have worked diligently to bring about a settlement that allows our cooperative to continue to meet our members' future power needs while bolstering our commitment to the environment," East Kentucky Power President and CEO Bob Marshall said in a news release. "This settlement fits well with East Kentucky Power Cooperative's existing plans for complying with tougher environmental standards that go into effect in the next few years. It also removes the risks and high costs of this litigation so our cooperative can focus on serving our members."

East Kentucky Power said it will make the pollution retrofit investment over the next five to seven years.

Terms of the settlement include installation of SO2 scrubbers and associated equipment at two generating units to meet tougher standards of the federal Clean Air Interstate Rule (CAIR) and Clean Air Mercury Rule (CAMR). The agreement also calls for year-round operation of NOx controls, rather than just during the warm weather months, continuous monitoring for mercury and particulate matter levels, and strict limits on the purchase, sale or transfer of emissions allowances.

East Kentucky Power also said in its press release that by the end of 2009, it must choose either to install emissions control equipment on the Cooper 2 generating unit, or to retire or repower its Dale units 3 and 4.

A company spokesman declined to comment further.

The EPA said that the utility must also construct and demonstrate new technology to significantly reduce sulfuric acid mist emissions from coal plants.

In 2004, the federal government filed a lawsuit against the utility for illegally modifying and increasing air emissions at two of its coal-fired power plants. Specifically, the government cited the utility for constructing modifications at its plants without first obtaining necessary pre-construction permits and installing required pollution control equipment. Without the required permits or pollution control equipment, the modifications allowed the facilities to increase their electricity and steam production rates and, as a result, emit more pollutants.

Some sources have said that EPA has more leverage in negotiating settlements to New Source Review litigation since the government won a key procedural battle with Duke Energy Corp. before the U.S. Supreme Court earlier this year.

COMPANIES REFERENCED IN THIS ARTICLE:

East Kentucky Power Cooperative Inc.

Duke Energy Corp. DUK

E-mail this story.

East Kentucky Power to run SCRs year-round at two Spurlock units

by Wayne Barber

East Kentucky Power Cooperative Inc. must operate selective catalytic reduction technology year-round to limit nitrogen oxide emissions from units 1 and 2 of the H.L. Spurlock power plant under terms of a consent decree reached with the federal government.

East Kentucky announced July 2 that it would spend about $656 million to install new pollution controls and settle ongoing New Source Review litigation under the Clean Air Act. The utility also agreed to pay a $750,000 fine, although it admits no violations.

SCR systems typically run during the so-called "ozone season," which includes the warm weather months of May through September. Legal settlements, such as the one that East Kentucky agreed to with the U.S. Environmental Protection Agency and U.S. Department of Justice, increasingly mandate continual use of such NOx control systems.

The consent decree spells out some of the steps that EKPC must take to keep certain coal units operating.

EKPC must start running the SCR technology year-round for Spurlock units 1 and 2 within 60 days after entry of the consent decree. By 2013, the consent decree stipulates that EKPC "achieve and maintain" a 30-day rolling average emission rate not greater than 0.100 lb/MMBtu for each of the two units.

EKPC must also install sulfur dioxide scrubbers or equivalent technology at Spurlock 2 by October 2008, and by June 2011 at Spurlock 1.

Also, by the end of 2009, EKPC must say in writing whether it will install and operate SO2 and NOx controls at its J. Sherman Cooper 2 unit by the end of 2012.

If such controls are not installed at Cooper 2, the utility would then have to retire units 3 and 4 and its Dale plant. Both of the affected Dale units can generate 80 MW. EKPC could later repower those units with newer technology.

Repowering can include replacement of an existing pulverized coal boiler through the construction of a new coal-fired circulating fluidized bed facility or other clean coal technology that meets certain 30-day rolling average emission rates for SO2, NOx and particulate matter.

EKPC brought online its first CFB unit a couple of years ago and is developing three more at its Spurlock and J.K. Smith power stations. At the end of its current CFB building phase, East

Kentucky will have four CFB units that together account for more than 1,200 MW of capacity.

Repowering can also include the modification or replacement of a unit with combined-cycle natural gas generation technology.

EKPC will have 12-month systemwide rolling tonnage limits for NOx starting in 2008. The system's annual NOx limit will decrease to 8,000 tons in 2015.

The settlement agreement also dramatically restricts EKPC's ability to sell or trade any NOx allowances. EKPC can only use NOx allowances to meet its own federal or state Clean Air Act needs.

COMPANY REFERENCED IN THIS ARTICLE:

East Kentucky Power Cooperative Inc.

E-mail this story.

Michigan seeks to add IGCC as benchmark in coal power permitting process

by Barry Cassell

With the state of Michigan encouraging coal-fired power development for energy security and diversity needs, the Michigan Department of Environmental Quality is now taking comment on a plan to add integrated gasification combined-cycle technology as a benchmark in the permit review process.

The MDEQ will take comment until Aug. 8 on its proposal to add IGCC technology as part of the Best Available Control Technology (BACT) determination process. Both federal and state regulations require the use of BACT in the permitting of large air emissions sources, such as coal-fired power plants. BACT is an emissions limit based on the maximum degree of reduction for a pollutant and is determined on a case-by-case basis.

"It is important to note that the BACT limit cannot result in an impact above an air quality standard or any state or federal regulation," said MDEQ in a public notice. "Additionally, BACT takes into consideration control options that are achievable through the application of available methods, 'including fuel cleaning or treatment or innovative fuel combustion techniques.' The MDEQ is proposing that IGCC be considered along with other available methods for BACT review as part of the permitting process for coal-fired electric generating units."

So far, IGCC has not been proposed for new coal capacity in Michigan. Consumers Energy Co., a unit of CMS Energy Corp., filed with the state Public Service Commission on May 1 a future energy plan that includes a 750-MW plant to be located at one of Consumers' existing coal plants. That project would use either pulverized coal or fluidized-bed combustion technology. LS Power Group and Dynegy Inc. are also in the early stages of developing a 750-MW pulverized coal plant, called the Mid-Michigan project, in Midland, Mich.

Said MDEQ in a fact sheet on the BACT review process: "Michigan's 21st Century Energy Plan (Plan) dated January 2007 identifies the need for new coal-fired generating capacity. The Plan acknowledged that coal will remain a large part of Michigan's portfolio for the foreseeable future. As a result, the [MDEQ] anticipates several permit applications in the near future. After consideration of the applicable federal and state requirements, the impact on emissions, and the recent permitting activities throughout the country, the MDEQ is proposing to require the consideration of [IGCC] as part of the air permitting process for electric generating units."

MDEQ added: "IGCC technology has progressed from an experimental technology. There are two existing installations of IGCC technology for power generation in the United States. One is located in Tampa, Florida and the other is in Terre Haute, Indiana. Both of these installations were partially funded by U.S. Department of Energy money. More IGCC facilities are planned. There are at least three IGCC facilities in the Great Lakes Region that have been permitted, or are in the final states of permitting. The MDEQ is aware of approximately 13 new IGCC units in the planning stages throughout the country. The availability and reliability of IGCC facilities has been steadily increasing, and new IGCC facilities have reliabilities comparable to conventional coal-fired power plants."

The agency noted that with the advent of climate change as a national issue, the ability to capture and sequester CO2 emissions has become a concern related to coal-fired power plants. It pointed out that Michigan has unique geological formations that could make carbon sequestration in Michigan both economically and technically advantageous.

"IGCC has a much higher potential for carbon capture than conventional facilities," said MDEQ. "As climate change strate-

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gies are implemented, these considerations will serve to offset IGCC's higher capital and operating costs in Michigan more than in other locations."

MDEQ pointed out that the states of Illinois, Kentucky and New Mexico require IGCC to be considered as a control option in their BACT determinations. Two IGCC power plants, the Taylorville Energy Center in Illinois and the Cash Creek Generation Station in Kentucky, have recently been permitted or are in the final stages of permitting, the agency added. Taylorville, which received its air permit on June 5, is backed by Tenaska Inc. Cash Creek's draft air permit went up for public comment in May, with the project backed by MDL Holding Co. LLC (formerly known as ERORA Group LLC).

"In cases where states have not included IGCC technology as a part of their BACT review, legal challenges have been filed," said MDEQ. "These cases are still pending resolution approximately four to five years after permit issuance. It is likely that permits in Michigan would be challenged if IGCC is not included as a part of a BACT determination."

COMPANIES REFERENCED IN THIS ARTICLE:

Consumers Energy Co.	
CMS Energy Corp.	CMS
Dynegy Inc.	DYN
ERORA Group LLC	
LS Power Group	
Tenaska Inc.	

E-mail this story.

Developers plan Washington IGCC with CO2 sequestration

by Wayne Barber

A venture that includes an Edison International subsidiary is pursuing plans to develop an integrated gasification combined-cycle power plant in Washington state that would burn Powder River Basin coal and sequester carbon dioxide emissions in underground basalt formations.

The Wallula Energy Resource Center, located about 15 miles from Pasco, Wash., in Walla Walla County, would be rated between 600 MW and 700 MW. The project is expected to cost roughly $2.2 billion, spokesman Timothy Killian said July 5.

The developers hope to file an application with the Washington Energy Facility Site Evaluation Council before the end of the year, but that depends to a great extent on a pilot project for carbon sequestration that will be conducted at the site this fall by the Big Sky Carbon Sequestration Partnership and the U.S. Department of Energy.

The plant would inject the captured CO2 into basalt formations more than 1.3 miles underground. The nearby Battelle National Laboratory has done promising research on basalt's ability to permanently store carbon. The plans call for permanent carbon sequestration to be done from plant startup, rather than years down the road.

Washington-based United Power Co., along with Quigg Energy and Oregon-based Sunwest Management, formed Wallula Resource Recovery LLC. The entity will pursue development of the IGCC project with Edison Mission Group Inc., which is helping fund much of the early up-front costs, Killian said.

The developers announced June 14 that the Port of Walla Walla had approved an option for the Wallula Energy Resource Center to acquire land for potential development of the IGCC project. The site already has a nearby 300-MW wind farm, with ethanol and biodiesel plants planned for construction nearby.

United Power CEO Robert Divers secured a permit from the siting council several years ago for a natural gas-fired plant at the Walla Walla site, though it was never built.

The emissions that result from the IGCC plant would be no more than a natural gas-fired plant and the CO2 would be sequestered underground, Killian said.

Passage of state legislation earlier this year, with a CO2 standard of 1,100 lbs/MWh, and growing power demand in the Northwest are drivers behind the project.

Fluor Corp. and Mitsubishi Heavy Industries would be two of the lead vendors on the project. Killian understands that Fluor will oversee plant design and construction and Mitsubishi will be the lead equipment provider.

The project could provide 530 construction jobs over 40 months, as well as more than 100 permanent jobs.

The developers plan to file their application with the EFSEC in September. They hope to have siting council certification by late 2008 and negotiate a power contract by late 2009. Conversations are already occurring with some potential customers, Killian said. The proposed online date is 2013.

The proposed plant site has ample infrastructure, with access to both the Union Pacific and Burlington Northern Santa Fe rail lines. It will be located in an industrial zone with access to a four-lane highway as well as a TransCanada Corp. gas pipeline. It has access to high-voltage transmission lines controlled by the Bonneville Power Administration.

The developers plan to apply for federal investment tax credits.

COMPANIES REFERENCED IN THIS ARTICLE:

Edison International	EIX
Bonneville Power Administration	
Edison Mission Group Inc.	
Fluor Corp.	
TransCanada Corp.	TRP

E-mail this story.

Scrubber costs play prominent role in Georgia Power's latest rate filing

by Barry Cassell

Environmental costs associated with various clean-air rules, including a Georgia multipollutant rule that mandates specific controls on specific power units by firm deadlines, make up the bulk of a Georgia Power Co. rate relief request filed June 29 with the Georgia Public Service Commission.

The multipollutant rule, which was released in draft form in March and adopted by the state Board of Natural Resources on June 27, mandates SO2 scrubbers, selective catalytic reduction for control of NOx, sorbent injection for mercury and baghouses for particulates. Georgia Power plans to spend approximately $9.1 billion over the next five years (2007 through 2011) in additional capital expenditures to meet this and other needs.

Georgia Power, a unit of Southern Co., is installing substantial pollution control facilities at Bowen, Harllee Branch, Hammond, Scherer, Wansley and Yates to comply with changing environmental regulations, the utility said in the rate filing. "These are very capital intensive and complex projects. The investments in these projects and the scope of the work involved often rivals the original plant construction. In fact, in many ways, these projects are more challenging than the original construction because they are being installed on existing units. At Plant Bowen, for instance, the environmental controls are more expensive than the original cost of the plant. It is important to bear in mind that while these projects are costly, they do not add to our generating capacity. Most of these control facilities consume, rather than generate energy."

For example, Georgia Power is building and now plans to build in the future scrubbers on its largest coal units. The scrubber in-service schedule is: Bowen Units 1-2, early 2009 and early 2010; Bowen 3-4, early 2008 and late 2008; Branch 1-2, 2014; Branch 3-4, 2013 and 2014; Hammond 1-4, early 2008; Scherer 1-2, 2013 and 2014; Scherer 3-4, 2011 and 2012; Wansley 1-2, late 2008 and early 2009; and Yates 6-7, 2014.

Georgia Power points out to the PSC that these are very large units. "As an example, the four units at Plant Bowen generate 3,160 MW of electricity, enough to power over 2 million homes. To provide this energy, Plant Bowen utilizes about 8.8 million tons of coal each year, or 24,000 tons per day. Plant Bowen requires about 220 rail cars per day, carrying 110 tons per car, to deliver that volume of coal. While the plant needs coal shipped in to generate electricity, the scrubbers will require about 750 tons of limestone per day. Plant Bowen will use three, 65-railcar trains per month to ship the limestone to the plant, where it will be stored and prepared. For perspective, the daily volume of limestone is the equivalent of a pile the size of a baseball infield, a little over a foot deep."

Georgia Power added: "The size and scope we have described for Plant Bowen varies with plant size, ranging from 800 MW at Plant Hammond to 3,280 MW at Plant Scherer. The task at Plant Scherer is larger and more difficult since this plant burns sub-bituminous coal and utilizes about 15.2 million tons of coal per year." The utility did not say in the PSC filing what kind of coal Scherer will use after the scrubbers are operating. Sister utility Gulf Power Co., which owns a piece of Scherer, told Florida regulators earlier this year that the Scherer scrubbers will likely be designed to handle PRB coal, with an option to go to higher-sulfur coal.

Georgia Power said it has seven scrubbers and two baghouses under construction at this time. Another seven scrubbers, 10 SCRs, and two baghouses are in preliminary engineering. Two coal units at the Jack McDonough plant would have gotten emissions-control technologies that are mandated by the multipollutant rule, but Georgia Power instead has found it cheaper to shut them early next decade and add gas-fired capacity at the McDonough site to more than replace them. The same economic study that prompted the McDonough replacement plan showed that with the costs of future emissions controls, it would be economic to retire Yates Units 6 and 7 by 2015, but the utility wants to keep them open for system reliability and fuel diversity reasons. (25060)

COMPANIES REFERENCED IN THIS ARTICLE:

Georgia Power Co.	
Gulf Power Co.	
Southern Co.	SO

E-mail this story.

Indiana approves pollution control upgrades at NIPSCO's Schahfer plant

by Mike Niven

The Indiana Utility Regulatory Commission on July 3 approved Northern Indiana Public Service Co.'s request to make approximately $23 million in pollution control upgrades to its coal-fired R.M. Schahfer plant.

NIPSCO, a unit of NiSource Inc., filed a petition with the IURC in December 2006 seeking permission to upgrade Schahfer's emissions controls to comply with the federal Clean Air Interstate Rule and Clean Air Mercury Rule, and looming state rules on fine particulate matter. Schahfer, with an operating capacity of 1,625 MW, is the largest generating station in NIPSCO's fleet.

Plant upgrades approved by the commission include the construction and installation of a low-NOx burner system with separate overfire air on Schahfer Unit 15, as well as the modification and upgrade of the existing SO2 scrubbing equipment on Schahfer units 17 and 18. Schahfer units 17 and 18 were equipped with wet flue gas desulphurization systems in the mid-1980s.

NIPSCO officials testified during the petition process that Schahfer will continue to burn the same types of coal it does now once the upgrades are complete. Units 17 and 18 currently burn high-sulfur coal sourced out of the Illinois Basin, while Unit 15, which does not have a scrubber, burns low-sulfur coal from the Powder River Basin.

The IURC also determined that the Schahfer upgrades constitute "qualified pollution control property," and thus approved NIPSCO's request to recover the cost of the equipment through a ratemaking procedure. As part of its decision, the IURC also ordered NIPSCO to conduct a coal study to determine if a lower cost fuel option is attainable for Schahfer. Specifically, the commission wants NIPSCO to study the cost effectiveness of building a rail line extension to possibly lower transportation costs associated with bringing Indiana coal to the plant. The commission asked that the study be completed by Dec. 31, 2007. (43188)

COMPANIES REFERENCED IN THIS ARTICLE:

Northern Indiana Public Service Co.	
NiSource Inc.	NI

E-mail this story.

Interstate Power and Light files siting permit application for Iowa coal plant

by Ryan Self

Alliant Energy Corp. subsidiary Interstate Power & Light Co. filed an application with the Iowa Utilities Board for a general siting certificate for the utility's proposed 600-MW, coal-fired Sutherland Generating Station Unit 4.

Interstate Power & Light announced plans to build the new plant alongside its existing Sutherland Coal plant in Marshalltown, Iowa, in January. The plant is scheduled to come online in 2013. The original announcement included a commitment to acquiring wind-generated electricity as well.

"We look forward to working with our regulators and other interested parties throughout this process," Interstate Power & Light President Tom Aller said in a news release. "Through the construction of SGS Unit Four, our company is pleased to support Iowa's expanding bio-fuel economy by providing new sources of safe, reliable and environmentally responsible energy."

Alliant has said that the $1 billion plant will use state-of-the-art technologies, and may open the door for a biofuels plant to be set up next to the site.

The siting permit seeks to address IUB requirements concerning the use of area land, water and air resources and also how the plant fits in with regular utility operations and state economic development goals.

Interstate Power & Light anticipates the pre-certification decision by the IUB in the first quarter of 2008 and also plans on filing for advance ratemaking principles regarding Sutherland Unit 4 with the utilities board in the first quarter of 2008.

Central Iowa Power Cooperative and Corn Belt Power Cooperative have entered into letters of intent to become joint owners of the new plant.

COMPANIES REFERENCED IN THIS ARTICLE:

Alliant Energy Corp. LNT
Central Iowa Power Cooperative
Corn Belt Power Cooperative
Interstate Power & Light Co.

E-mail this story.

Kentucky coal plant developer granted more time to resolve problems

by Wayne Barber

The Kentucky State Board on Electric Generation and Transmission Siting has given the developer of a proposed 110-MW waste coal power plant until Sept. 15 to pay an additional $30,000 supplemental filing fee.

Estill County Energy Partners LLC paid an initial filing fee with its site application back in 2004. The board originally granted site approval in late 2004, but held open part of the case because of a legal dispute over ownership of a key part of the power plant property.

The board noted in 2005 that most of the original filing fee had been used up, although the property ownership issue remained unresolved. As a result, the board had ordered the additional $30,000 filing fee be paid by a June 15, 2007, deadline.

On June 13, however, the developer filed a motion seeking more time to pay the fee and file the supplemental site assessment report.

According to the Estill County partners' motion, the company has been involved in ongoing negotiations to resolve the property title issues and believes that resolution is probable in the near future. The company further believes it is close to lining up needed additional funding for the project.

In an order dated July 2, the siting board approved the extension to pay the fee, with certain conditions. The order noted that Estill County partners' siting application account has already dwindled to less than $6,300, which does not include almost six hours of time yet to be billed against the account for legal fees incurred in June.

"Therefore, if the balance of the application fee account drops below $1,000 during the interim between the date of this order and Sept. 15, 2007, the board may require ECEP to file its supplemental filing fee sooner than Sept. 15, 2007, in order to avoid an account deficit," the siting board said.

The order was issued by the executive director of the Kentucky Public Service Commission on behalf of the Kentucky State Board on Electric Generation and Transmission Siting.

Estill County Energy Partners wants to locate the 110-MW power plant on a former South-East Coal Co. mining site in Estill County, Ky., and to fire the plant with nearby waste coal. But the LaViers family, which owned South-East Coal, disputes whether the power developer actually controls the site. The family is trying to protect the property values of a nearby housing development in which it is involved, contending that values might be hurt by the presence of a power plant. (Case No. 2002-00172)

COMPANY REFERENCED IN THIS ARTICLE:

Estill County Energy Partners

E-mail this story.

OPPD refutes reports it is considering third Nebraska City unit

by Ryan Self

The Omaha Public Power District is not considering building a third coal-fired power plant at its existing Nebraska City plant, spokesman Jeff Hanson said.

"We are nowhere on that idea, despite reports to the contrary," Hanson said on July 5. "There are no talks whatsoever to do this."

The *Lincoln* (Neb.) *Journal-Star* newspaper carried an Associated Press report in its July 4 editions saying that OPPD was considering whether to build a third unit at the Nebraska City site. A second unit is now under construction there.

In its most recent integrated resource plan, OPPD projected that new generation will be necessary by 2016 to meet the growing demand for power, and Hanson said that building a third plant at the existing Nebraska City site — even as the utility continues construction on the $629 million, 663-MW Nebraska City 2 unit on the same site — would be the "lowest cost, most reliable option." However, he added that OPPD has yet to reach even the earliest stages of discussions on whether a third Nebraska City unit is needed.

"As we do every year, we're looking at changes in the industry and alternative fuels," Hanson said.

Hanson added that OPPD has formed a new division to look at sustainability and at increasing renewable generation and energy efficiency.

"They're just getting their feet on the ground right now," Hanson said.

OPPD plans to bring the second Nebraska City plant online by spring 2009, with an accompanying 345-kV transmission line to be completed shortly beforehand. The utility serves 310,000 customers in southeastern Nebraska.

COMPANY REFERENCED IN THIS ARTICLE:

Omaha Public Power District

E-mail this story.

California agency's staff cites concerns with one of two plant proposals

by Wayne Barber

California Energy Commission staff has found no early red flags to stop development of a 400-MW power plant in Fresno County, but has concerns that a 600-MW plant in Alameda County could affect air traffic at a local executive airport.

The CEC staff said July 2 that it could not recommend approval of the 600-MW Russell City power plant in Hayward, Calif., for fear that plumes from the plant's heat recovery steam generator stacks and cooling tower could create a possible aviation safety hazard at the Hayward Executive Airport. The plume would be within the Hayward safety zone.

Days earlier, the CEC staff issued a preliminary assessment that the Panoche power plant, a 400-MW, simple-cycle facility in western Fresno County, could be licensed without causing significant environmental impact. Energy Investors Funds Group announced in April 2006 that it had been awarded contracts by Pacific Gas and Electric Co. to build two power centers in Fresno County, including the 400-MW Panoche unit.

The Russell City plant was originally certified by the CEC in September 2002. Without a power purchase agreement, however, construction was never begun. Now, project owners Calpine Corp. and GE Energy Financial Services have a power purchase agreement with PG&E, a subsidiary of PG&E Corp.

In November 2006, the owners filed a request with the commission to move the proposed project site 1,300 feet from its previously approved location. The new site is about four acres larger than the first one and does eliminate some infrastructure complications for the developers.

When it sought the change, Calpine said the relocation would eliminate the need to move certain radio towers, add more parking for construction workers and reduce certain environmental and visibility impacts. The proposed changes are based on information that Calpine learned after the project was first certified. Likewise, certain property had become available that was unavailable before, Calpine told the commission.

While the staff assessment asserts that approving proposed changes to the existing conditions of certification will reduce the potential environmental impacts to less-than-significant levels, in the areas of land use and traffic and transportation, staff has found a potential aviation safety hazard.

Due to the proposed change in plant location, the staff has also proposed various changes to original conditions for various environmental, safety, transmission and socioeconomic issues. The staff will produce supplements to the land use and traffic and transportation sections that incorporate revisions based on the comments received. The staff anticipates filing this supplement on July 18.

The CEC siting committee for Russell City, which includes two commissioners, will hold a prehearing conference and evidentiary hearing July 19 on the Russell City project.

As for Panoche, the commission said June 28 that a preliminary staff assessment found no environmental problems serious enough to block licensing the project. After a 30-day public comment period, a final staff assessment will be issued.

Panoche is to be located on a roughly 13-acre site about 12 miles from Mendota, Calif., in western Fresno County. The $300 million project will include four gas-fired combustion turbine generators.

The San Joaquin Valley Air Pollution Control District has determined that the project complies with the district's air quality rules. The applicant has identified all required emissions reduction credits needed for operation of the plant.

If permitting goes as planned, construction on the plant would start in January 2008 and operation could commence in the first quarter of 2009.

On another power plant siting issue, the CEC said that a public hearing and site tour for Reliant Energy Inc.'s proposed 656-MW San Gabriel power plant was scheduled July 6 in Rancho Cucamonga, Calif.

COMPANIES REFERENCED IN THIS ARTICLE:

Energy Investors Funds Group	
Calpine Corp.	CPNLQ
GE Energy Financial Services	
Pacific Gas and Electric Co.	
PG&E Corp.	PCG
Reliant Energy Inc.	RRI

E-mail this story.

Fitch finds reason for optimism on Calpine

by Wayne Barber

Tighter regulation of emissions from coal-fired power plants, the slowdown in construction of new plants and stabilization in gas markets should give Calpine Corp. an increased chance of success when it exits bankruptcy, Fitch Ratings said.

The slowdown in construction of new generating capacity could help a reorganized Calpine compete better when it emerges from Chapter 11 bankruptcy, expected by the end of 2007, Fitch Ratings said in its June 25 commentary.

In its analysis, Fitch also credited Calpine management's efforts to stabilize operations and simplify the capital structure of the company.

The spike in new generation capacity between 2000 and 2003 contributed to Calpine's financial distress, but "since 2003, there has been little new capacity added, while demand for electricity has risen and compressed capacity reserve margins across the United States," Fitch analysts noted. Also, Fitch said the Energy Information Administration expects nearly 40% of additional demand by 2030.

"Tightening capacity markets has improved the capacity utilization rates for Calpine's plants," Fitch said, adding that all types of energy assets are enjoying higher valuation now, and this helps Calpine.

Fitch thinks the outlook for independent generation companies is generally positive, especially for those with gas-fired, combined-cycle and peaking assets.

Meanwhile, emission standards have become stricter, and there is increasing momentum toward enactment of some type of greenhouse gas legislation, Fitch said. "As a general rule of thumb, natural gas-fired generation capacity has one half the carbon intensity of coal-fired capacity," Fitch said. Calpine's geothermal fleet also profits from government incentives for renewable energy.

"The value of the assets has increased as a result of the long-term expectation of more stringent regulations of carbon emissions," Fitch said.

The volatility of natural gas prices has also played with Calpine's business model and valuations for the past couple of years, Fitch said. Natural gas prices on the New York Mercantile Exchange were at an inflated level of $13.66/MMBtu on Dec. 5, 2005, when Calpine sought bankruptcy reorganization, and spark spreads were bottoming out, compared to late June 2007 prices of less than $7/MMBtu.

"High natural gas prices typically worsen the competitive position of gas-fired power plants and lower the plants' dispatch rates in markets with substantial amounts of coal and nuclear capacity," the Fitch report said. "However, Calpine's gas-fired assets tend to be in regions with narrow reserve margins where natural gas plants tend to be dispatched for more hours of the year. Also, Calpine owns some geothermal assets in the West that benefit more directly from higher gas prices.

"On balance, Calpine's assets are likely to gain value from high natural gas prices," the report said. "On the other hand, the gas price spike that began in late 2005 impaired Calpine's liquidity and solvency and was one impetus for the bankruptcy filing."

Currently, gas prices are well below their 2005-2006 peak, but high relative to long-term historical values, the report said. "Calpine's viability as a reorganized entity will depend on having effective arrangements to deal with volatile working capital and collateral requirements."

COMPANY REFERENCED IN THIS ARTICLE:

Calpine Corp.	CPNLQ

E-mail this story.

Duke Energy Carolinas updates plans for two gas-fired plants in North Carolina

by Andrew Engblom

Duke Energy Carolinas LLC expects to formally file in September for certificates of public convenience and necessity for two 600-MW to 800-MW, gas-fired power plants in North Carolina, the company said in two recent filings with state regulators.

The two filings on June 29 include updated "preliminary information" for a planned CPCN filing for the Buck combined-cycle project in Rowan County, N.C., and an initial filing for the Dan River combined-cycle project in Rockingham County, N.C.

The company said in both filings that it would make the CPCN filings after it submits its 2007 annual plan, currently under development

According to the filings, the Buck plant would come online as early as 2010, while the Dan River plant could come online as early as 2011. Both are designed to offer intermediate generating capacity.

The company's 2006 annual plan showed demand growth of approximately 1.7% per year, resulting in a need for 810 MW of additional capacity by 2010.

The company also said it is exploring the wholesale market to consider purchased-power options to "satisfy all or a portion of its intermediate needs," noting a request for proposals that it issued May 14 that seeks up to 800 MW of peaking and/or intermediate generation in 2010 and up to 2,000 MW of such generation by 2013.

Duke first filed its plans for the Buck project in May 2005, but a spokeswoman said the company had previously been able to hold off development of the project.

The new unit would join four coal-fired units and three combustion-turbine units currently operating at the Rowan County site, along with two units that are no longer in operation.

The Dan River site includes three coal-fired units and three combustion-turbine units.

Duke Energy Carolinas is a subsidiary of Duke Energy Corp. (Buck: E-7, sub 791; Dan River: E-7, sub 832)

COMPANIES REFERENCED IN THIS ARTICLE:

Duke Energy Carolinas LLC	
Duke Energy Corp.	DUK

E-mail this story.

Connecticut Consumer Counsel objects to three of four winning bids in capacity RFP

by Corina Rivera

The Connecticut Office of Consumer Counsel asked the state Department of Public Utility Control on June 29 to reject three of the four electric capacity contracts that the DPUC provisionally approved following completion of its request for proposals process.

The DPUC on May 3 formally accepted the four projects, totaling an aggregate 787 MW, as winning bidders in its RFP for new capacity. This portfolio of projects consists of a 620-MW, natural gas-fired, combined-cycle baseload plant; a 66-MW, oil-fired peaking facility; a 96-MW, gas-fired peaking facility; and a 5-MW statewide energy efficiency project.

The RFP process was mandated by the state's Energy Independence Act legislation and is intended to help resolve electrical capacity shortages in Connecticut, thereby reducing the special "federally mandated" charges that appear on Connecticut Light and Power Co. and United Illuminating Co. customers' bills, the OCC said in its June 29 statement.

The OCC said that while it strongly supports these policy goals, it has concluded that London Economics International LLC, the DPUC's expert consultant, has not justified final approval of the entire group of recommended projects.

"We have to be confident that these four projects are cost-effective before ratepayers are required to pay for them," Consumer Counsel Mary Healey said in the statement. "The total price tag for these projects could be almost 2 (two) billion dollars over the life of the contracts. That is why OCC undertook to thoroughly analyze the LEI Report."

The OCC said it believes that only one of the four projects — the 66-MW peaking plant — could be cost-effective. The OCC said it made its recommendations in a detailed report, prepared by its independent expert, Resource Insight Inc., and filed with the DPUC on June 29.

These electric capacity contracts, and the OCC's analysis of them, are expected to be the subject of DPUC hearings starting July 9 in Docket No. 07-04-24.

Resource Insight officials said in direct testimony on behalf of the OCC that a needs assessment found that locational installed capacity would be enough in Connecticut until 2018, but that roughly 625 MW of quick-start peakers would be needed to meet the state's requirement for forward reserves to ensure reliability and to reduce costs.

In the bid evaluations, Resource Insight said, London Economics increased the projected base-case locational forward reserve market shortfall to 650 MW in 2010, rising to 681 MW in 2012.

Instead of evaluating whether the proposed projects could economically contribute to satisfy the 650-MW reserve shortfall, London Economics assumed that this need is met with the addition of 700 MW of generic combustion turbines in the state in 2010, Resource Insight added.

Consequently, the evaluation does not consider the technical or economic feasibility of bringing on 650 MW of locational forward reserve market capacity, or the effects of achieving only part of that goal, according to Resource Insight.

Among other things, Resource Insight said that if the DPUC is to review the structure or results of a future RFP for new resources, the analysis should address such key issues as how much locational forward reserve market capacity is likely to be added in response to market prices.

DPUC spokeswoman Beryl Lyons said July 3 that a draft decision on the matter is slated for Aug. 1 and the final decision is scheduled for Aug. 15. She said the DPUC will make an official response to the OCC's filings in the docket.

Connecticut Light and Power is a subsidiary of Northeast Utilities. United Illuminating is a subsidiary of UIL Holdings Corp.

COMPANIES REFERENCED IN THIS ARTICLE:

Connecticut Light and Power Co.	
Northeast Utilities	NU
UIL Holdings Corp.	UIL
United Illuminating Co.	

E-mail this story.

CEGT contracts to build 16-mile pipeline to serve Arkansas power plant

by Hill Vaden

CenterPoint Energy Gas Transmission Co. said July 2 that it has contracted with Southwestern Electric Power Co. to construct about 16 miles of pipeline in Oklahoma and Arkansas that will serve a new 480-MW power plant in Washington County, Ark.

The pipeline and related compression will be built in two phases. Phase one consists of 2,300 feet of 12-inch-diameter pipeline and a delivery meter station at the Harry D. Mattison power plant. Phase one should come online in the third quarter of 2007.

Phase two involves adding a 15,000-horsepower compressor station near Poteau, Okla., and 15.5 miles of 24-inch-diameter pipeline looping of CEGT's Line OM-1. It should come online in the second quarter of 2009, pending FERC order.

The CenterPoint Energy Inc. indirect subsidiary said it plans to file an application with FERC for authorization of the second phase.

SWEPCO, a subsidiary of American Electric Power Co. Inc., is constructing two simple-cycle natural gas combustion turbines that will offer a combined capacity of 170 MW when complete in July 2007. Another two combustion turbines, with a combined capacity of 170 MW, are scheduled for completion in December 2007.

Details of the pipeline contracts are confidential.

COMPANIES REFERENCED IN THIS ARTICLE:

CenterPoint Energy Gas Transmission Co.	
American Electric Power Co. Inc.	AEP
CenterPoint Energy Inc.	CNP
Southwestern Electric Power Co.	

E-mail this story.

New Jersey becomes third state to make greenhouse gas reduction goals law

by Kelly Harrington

New Jersey Gov. Jon Corzine on July 6 signed legislation calling for a series of greenhouse gas emissions reductions by 2050.

The legislation, overwhelmingly backed by the General Assembly in June, requires New Jersey to cut greenhouse gas emissions to 1990 levels by 2020, a roughly 20% drop, followed by additional emissions reductions of 80% below 2006 levels by 2050. With Corzine's signature, New Jersey is the third state in the country to make greenhouse gas reduction goals law.

"In the absence of leadership on the federal level, the burden of reducing greenhouse gases has now fallen upon the states," Corzine said. "I'm proud that New Jersey is one of the first among a handful of states that are leading the nation to combat global warming and I hope more states will follow in our model."

The commissioner of the Department of Environmental Protection will work with the Board of Public Utilities, Department of Transportation, Department of Community Affairs and other stakeholders to find ways to reach and exceed the 2020 target reductions. This evaluation will be done in conjunction with the state's ongoing energy master plan, which will incorporate the new greenhouse gas reduction goal, the governor said.

DEP will also develop a 1990 greenhouse gas emissions inventory and a system for monitoring current greenhouse gas levels so that progress toward the goals can be accurately tracked. The department will report progress towards the target reductions to the governor and lawmakers no less than every two years and, if necessary, will recommend additional actions to reach the targets. The state will also develop targets and implementation strategies for reducing energy use by state facilities and vehicles fleets.

Supporters of the legislation, such as Environment New Jersey, Public Service Enterprise Group and the Sierra Club, echoed Corzine's remarks that the requirement will make the state a national leader.

"Because of its strong stand against global warming, New Jersey will be a laboratory of innovation for environmental benefit — a role that plays to its strength as one of the world's leading centers for technology-driven economic growth," said PSEG Chairman, President and CEO Ralph Izzo.

The requirements meet up with those outlined in an executive order from Corzine in February.

E-mail this story.

NRC consolidates new security rules for nuclear plants

by Wayne Barber

The U.S. NRC said June 27 that it has started consolidating existing security changes for each of the nation's nuclear power reactors, including requirements enacted since the Sept. 11, 2001, terrorist attacks.

The changes include a requirement that nuclear plant owners be prepared to handle the effects of fires and explosions that could result from a terrorist attack, including the impact of a large aircraft.

The site-specific safety evaluation reports are part of a broader agency effort over the past five years to upgrade plant safety and security, the commission said.

Most of the measures being required, through revisions to plant operating licenses, are already in place and have been verified by the NRC. Other measures will be completed by December 2007.

"From the outset we set very high standards for plants to meet," NRC Chairman Dale Klein said in a news release. "Today's action consolidates the steps we have required over the past five years."

In February 2002, the NRC ordered a series of security upgrades at nuclear plants nationwide. In addition to increasing physical security, the commission had plants add measures to mitigate the possible effects on spent fuel pools, reactor cores and containment buildings of a deliberate or accidental crash of a large commercial airplane.

Various public interest groups have been pushing for more analysis on the effects of a potential plane crash at a nuclear plant.

E-mail this story.

NRC considers FirstEnergy response on Davis-Besse data

by Wayne Barber

After a June 27 meeting with FirstEnergy Corp. officials, the staff of the NRC is continuing to evaluate the company's response to a "demand for information" letter for data surrounding corrosion that weakened the reactor at the Davis-Besse nuclear plant in 2002.

During the meeting, the NRC raised concerns with FirstEnergy over the company dragging its feet in sharing with the commission results of an analysis that the company paid for in pursuit of an insurance claim surrounding the vessel head replacement at Davis-Besse.

The NRC is now reviewing FirstEnergy's comments during the meeting to see if anything else needs to be done, said NRC spokesman Scott Burnell. The demand letter, issued to the company in May, helps the commission determine if it needs to take further enforcement action.

The NRC is sharing the information it has received from FirstEnergy with the U.S. Justice Department, Burnell said June 29, adding that no additional meetings are currently scheduled with the company.

FirstEnergy Nuclear Operating Co. agreed in 2006 to pay a fine of $28 million because of the problems at Davis-Besse. The Justice Department agreed not to seek a criminal indictment against the FirstEnergy unit. In April 2005, the NRC proposed a fine of approximately $5.5 million, which the company paid.

The principal NRC violation was that FirstEnergy restarted and operated the Davis-Besse plant in May 2000 without fully characterizing and eliminating leakage from the reactor vessel head, which led to significant corrosion damage.

"The unsatisfactory nature of FENOC's initial response" was discussed during the June 27 meeting, Burnell said.

NRC is not questioning the current safe operation standards of Davis-Besse or FirstEnergy's other nuclear plants, Burnell added.

The company took the Davis-Besse plant offline in 2002 to replace the damaged head, a project that took about two years, until April 2004. Expenses directly related to the physical plant improvements totaled roughly $300 million, and the company spent an additional $300 million on replacement power while the 939-MW reactor was offline.

FirstEnergy filed a $200 million insurance claim seeking to recoup the cost of the replacement vessel head and a portion of the replacement power costs. The insurance claim was denied in 2004 and FirstEnergy has been in arbitration over the claim's rejection.

FirstEnergy has acknowledged that it should have kept the NRC better informed about technical reports on problems at the pressurized water reactor. Company representatives could not immediately be reached for comment.

COMPANIES REFERENCED IN THIS ARTICLE:

FirstEnergy Corp.	FE
FirstEnergy Nuclear Operating Co.	

E-mail this story.

Cooperatives explore joint investments in renewables to reduce emissions

by Kathleen Hart

As the focus of the Congress has shifted to climate change, some rural electric cooperatives have started looking into the possibility of jointly investing in renewable resources with the goal of reducing greenhouse gas emissions.

"If the overall objective is to produce as much renewables as possible as a country, rural cooperatives are in a good position to do that," National Rural Electric Cooperative Association CEO Glenn English said in a meeting with reporters on July 2 in Washington, D.C.

"We've got a number of members mulling this over, trying to think, 'Is this possible? Is this an idea that should be advanced?' It's a concept right now," English said. Several larger member co-ops who are exploring the concept held a meeting in Kansas City, Mo., last week to explore how it would work.

If the United States has an objective of producing more renewable energy, "this may be a way we can make a contribution in that direction," he added.

The idea behind the concept would be to move power from the Great Plains and other regions of the country rich in wind to areas in the Southeast that lack wind resources. If electric cooperatives in disparate regions of the country came together to do that, transmission will need to be built to move power out of the areas that have wind and hook into the grid, English said.

"Why shouldn't the folks in the Southeast be a party to building that generation in the Great Plains?" English asked, suggesting that it could be done on the basis of incentives.

However, some existing laws stand in the way of electric cooperatives doing that, English said. Under current tax law, any co-ops that produced wind power and received money for generating the power, beyond the 15% revenue level currently allowed under the tax code, would jeopardize their tax-exempt status, he explained.

"If you had distribution cooperatives who invested in that, and that power got sold, the return that they got off it would likely put them over the 15% they are allowed," English said, adding that the law may need to be changed. "The law as it was originally written makes sense, but if you start trying to shift to different priorities, some laws may need to be tweaked."

In addition to possible changes in tax law, English said that the nation would need to grapple with how to get the transmission lines built to deliver the wind power.

"In trying to move wind power from the Dakotas into Chicago, some states have taken the position that if that power isn't going into their state, they don't want transmission built in their state," English said.

While a lot of what stands in the way is a NIMBY (not in my backyard) perspective, there is also a larger question of whether the nation actually has an overall plan to reduce carbon emissions and address climate change, English argued.

"The way we see everything now, everything is connected to climate change. I think that's where the Congress is," English said. "That's where their head is right now. They're focused on that, and I think anything you take up, you've got to assume there's going to be some kind of connection to climate change or you're going to have to address it in that fashion."

English urged Congress to back up a little and view the various pieces of the climate change issue as a package. "It is going to require a better understanding of this industry to do this wisely and some resistance to taking the easy way out," he said.

"The easy way out is to lump everyone together, give everyone a number and say you've got to meet that number by some arbitrary date," English added. "I think there's a learning curve that needs to take place among members of Congress over the next several months, and the debate will become more refined."

While English anticipates some kind of legislation getting through Congress this year, he expects that lawmakers will be addressing various pieces of the climate change issue for years to come.

"Normally, good legislation needs to cook awhile. People have got to thrash it around, get used to it," English, a former member of the House of Representatives from Oklahoma, said of the current fervor in Congress to pass legislation to address global warming. "I think the knowledge level is not up to the fervor."

English believes it is important to ask Congress "to back up right now and determine how to do this in the right way."

E-mail this story.

Sempra, Ormat among suppliers chosen to provide SoCalEd with renewables

by Wayne Barber

Southern California Edison Co. said July 2 that it has signed six long-term contracts with different providers for a total of 480 MW from renewable power sources.

The Edison International subsidiary will obtain power from wind, geothermal, biomass and photovoltaic sources. All six agreements, five of which are for 20-year terms, are subject to approval by the California Public Utilities Commission.

The larger of the two wind contracts is with Sempra Generation, a subsidiary of Sempra Energy, for up to 250 MW from the La Rumorosa wind facility being developed in Baja California, Mexico.

Under the contract, Sempra Generation could start delivering power to SoCalEd in 2010.

The La Rumorosa project is Sempra Generation's first venture into wind. On June 29, the company announced it had agreed to acquire the development rights associated with La Rumorosa under a co-development arrangement with San Diego-headquartered Cannon Power Corp. Sempra said it is also looking for solar and other renewable projects in the Southwest.

The La Rumorosa project would generate power from as many as 125 wind turbines to be installed along the easterly ridge lines of the Sierra Juarez mountains in the Ejido Jacume near the town of La Rumorosa, about 70 miles east of San Diego and south of the U.S.-Mexico border.

The second wind power contract is a 20-year deal with Granite Wind LLC for output from a wind facility in Apple Valley, Calif. The agreement calls for 42 MW initially and 81 MW eventually, SoCalEd said.

SoCalEd said it is signing two agreements for geothermal power. One is a 20-year agreement with ORMAT Technologies Inc. for 50 MW from the Brawley 1 project now under construction in Imperial County, Calif. The power purchase agreement with Ormat includes an option to increase capacity to 100 MW at Ormat's discretion.

Ormat said the SoCalEd agreement is its largest power purchase agreement to date. When completed, the Brawley 1 project will increase the total output supplied from Ormat to SoCalEd to roughly 190 MW.

The second geothermal agreement is another 20-year deal, this one with Caithness Energy LLC for 50 MW from the Dixie Valley power unit in Nevada.

Additionally, SoCalEd has signed a baseload biomass contract based on a new power contracting option that the utility introduced in May to help smaller biomass generators. Finally, solar energy was added to the portfolio through a photovoltaic proposal.

The latter two contracts are for less than 2 MW each and involve a 10-year biomass power contract with Los Angeles County Sanitation and a 20-year photovoltaic contract with the California Sunrise 1 project.

SoCalEd said it serves between 16% and 17% of its customers' needs with renewable energy and hopes to reach 20% by 2010.

COMPANIES REFERENCED IN THIS ARTICLE:

Southern California Edison Co.	
Caithness Energy LLC	
Edison International	EIX
ORMAT Technologies Inc.	
Sempra Energy	SRE
Sempra Generation	

E-mail this story.

Cape Wind report: Proposed project would generate 321 MW during peak periods

by Jennifer Zajac

Data from Cape Wind Associates' scientific data tower indicates that the developer's proposed offshore wind generation facility would have produced an average of 321 MW during the times of greatest electric demand in New England.

According to the report, dated July 2 and titled "Comparison of Cape Wind Scientific Data Tower Wind Speed Data with ISO New England List of Top Ten Electric Demand Days," the 130-turbine wind farm, if built, would have produced 76% of Cape Wind's total capacity of approximately 420 MW during the times of greatest electric demand in New England, according to ISO New England Inc.'s list of its top 10 demand days.

"By providing this substantial supply of clean energy during times of greatest electric demand, Cape Wind would improve electric reliability, reduce air pollution, reduce wholesale electricity costs and increase energy independence," the report states. "Previously, the U.S. Department of Energy also found that Cape Wind would improve electric reliability during extreme cold winter conditions when availability of natural gas to generate electricity is reduced due to increased heating demand."

The "sea breeze effect," according to Cape Wind's seven-page report, occurs on hot and sunny summer days when the land surface heats up faster than the ocean surface, which increases the difference in the temperature of the air above the land compared with the ocean. The air temperature difference creates a difference in the density of air over land and ocean, causing a sea breeze.

Cape Wind's production would also be strong during extremely cold times. A June 2004 U.S. Department of Energy study, "Natural Gas in the New England Region: Implications for Offshore Wind Generation and Fuel Diversity," examined a three-day severe cold snap in January 2004, during which rolling blackout conditions in New England were contemplated due to the lack of availability of natural gas for power plants.

"The DOE study noted that Cape Wind's data tower was reporting the offshore wind farm would have been operating at full capacity during most of that three-day period, improving regional electric reliability," the Cape Wind report states.

The report notes that the wind farm would reduce air pollution generated by existing power facilities in the region, improve reliability in the region, provide a major step toward energy independence and reduce power costs. "The Massachusetts Energy Facilities Siting Board estimated that Cape Wind would reduce wholesale electricity costs by $25 million per year in New England by displacing the highest price electric units that would otherwise have needed to operate without Cape Wind," the report states.

The offshore wind project continues, however, to face opposition. In a June 21 column in the *Cape Cod* (Mass.) *Times*, Charles Vinick, president and CEO of the Alliance to Protect Nantucket Sound, applauded Gov. Deval Patrick's renewable energy efforts, noting his administration's exploration of deep-water wind turbines. "Advances in deeper-water technology make many sites — like the one Cape Wind has disregarded off the south side of Tuckernuck Island — viable and technologically realistic. In fact, it is likely that many more sites like this one should be considered. The Massachusetts coastline offers twice as much feasible water sheet for wind projects in 65- to 100-foot depths as shallower ranges like those targeted by Cape Wind," the column states.

Cape Wind Associates is a subsidiary of Energy Management Inc.

COMPANIES REFERENCED IN THIS ARTICLE:

Cape Wind Associates

Energy Management Inc.

E-mail this story.

New Hampshire siting committee clears way for wind project

by Kelly Harrington

The developer of New Hampshire's first commercial wind farm can move ahead with plans to construct the facility, a state siting committee said.

The New Hampshire Site Evaluation Committee on June 28 said Lempster Wind LLC's proposed 24-MW wind facility, among other things, will not interfere with the "orderly development" of the region and will not have an "unreasonable effect" on the environment. Timothy Drew, administrator for public information and permitting of the New Hampshire Department of Environmental Services, said the panel's approval is the last needed for the project to move forward.

Lempster Wind is a wholly owned subsidiary of Community Energy Inc., itself owned by Iberdrola Renewable Energies. Iberdrola Renewable is a wholly owned subsidiary of Spain-headquartered utility company Iberdrola SA, which is now planning to acquire Energy East Corp.

In August 2006, Lempster Wind filed an application for a certificate of site and facility to construct and operate the project, which will consist of 12, 2-MW turbines along Lempster Mountain in Lempster, N.H. The project, to be built on privately owned land, will run parallel to New Hampshire Route 10 and take up 35 to 40 acres.

The project will interconnect with a 34.5-kV distribution line owned by Public Service Co. of New Hampshire, a subsidiary of Northeast Utilities.

In its order, the 14-member committee also determined the company had adequate financial, technical and managerial capabilities and that the project is consistent with state energy policy.

While a representative from Community Energy did not immediately return a request for comment on July 5, the company on its Web site said it expects the project to be operating in 2008.

COMPANIES REFERENCED IN THIS ARTICLE:

Iberdrola SA	
Community Energy Inc.	
Energy East Corp.	EAS
Iberdrola Renewable Energies	
Northeast Utilities	NU
Public Service Co. of New Hampshire	

E-mail this story.

WP&L purchases 41 Vestas turbines for Cedar Ridge wind farm

by Grier McCain

Alliant Energy Corp. subsidiary Wisconsin Power and Light Co. said July 2 that it purchased 41 wind turbines from Vestas Wind Systems for construction of the Cedar Ridge wind farm.

The project will cover a 12.2-square-mile area in the townships of Eden and Empire in Fond du Lac County, Wis.

Each Vestas V82 turbine is capable of producing 1.65 MW of electricity for a project total of nearly 70 MW.

The cost of the construction of the farm is expected not to exceed $180 million. Once completed, Cedar Ridge will become Alliant Energy's first fully owned and operated wind farm.

Construction is expected to begin in August 2007, with the installation of turbine access roads, foundations and the substation. Turbine erection, assembly and commissioning, along with public road improvements and cabling will take place in 2008. The wind farm is expected to be online by the end of 2008.

COMPANIES REFERENCED IN THIS ARTICLE:

Wisconsin Power and Light Co.	
Alliant Energy Corp.	LNT

E-mail this story.

West Virginia developing five-year energy plan

by Ryan Self

West Virginia energy officials say they are beginning work on a five-year state energy plan that will focus on developing both coal resources and renewable energy options.

The state Department of Commerce recently consolidated its energy programs into a single Division of Energy, led by Director Jeff Herholdt. Herholdt said the new office — which replaces the state Office of Coalfield Community Development, Energy Efficiency Office and Public Energy Authority — will be composed of seven employees who will focus on all types of potential energy sources for the state.

"The change lets us look at how to advance renewables, energy efficiency and fossil fuels in concert," Herholdt said July 3. "The state has a lot of opportunities here."

Herholdt said it was too early to speculate on how the new state energy plan might take shape, but he did single out coal-to-liquids technology, ethanol development, use of state wood resources and renewable energy sources as areas that he would like to focus on.

"It's too early to say what opportunities may arise," he said. "Coal is the crux of our generation, but we agree with other states that have found opportunities in renewables."

E-mail this story.

New Brunswick utility purchases small hydro station

by Dave Todd

Provincial government-owned utility NB Power Holding Corp., through its NB Power Generation subsidiary, has added 10.8 MW to its renewable energy portfolio through the purchase of the Great Falls hydroelectric station near Bathurst, New Brunswick, in the province's northeast.

The plant was formerly used to power a paper mill that Smurfit-Stone Container Corp. closed in 2005. Neither Smurfit-Stone nor NB Power would disclose the sale price.

Marc Beliveau, a spokesman for New Brunswick Minister of Energy Jack Keir, said that "for competitive reasons, we cannot provide the detailed analysis of this acquisition."

Discussing the terms of the contract, including the cost of the purchase, "could impact future discussions to acquire additional renewable energy," Beliveau said.

The Great Falls station's three generators produce about 52 million kWh per year and raise NB Power's hydro capacity to 895 MW. The provincial utility also recently signed agreements to purchase 96 MW of wind energy by 2008 and has issued a request for proposals to add an extra 300 MW of wind capacity by November 2010.

The addition of Great Falls to NB Power's fleet of six other hydro stations "will provide additional energy from a source other than oil, thereby decreasing generation costs," the utility said.

COMPANIES REFERENCED IN THIS ARTICLE:

NB Power Holding Corp.

NB Power Generation

E-mail this story.

AMP-Ohio to take from Prairie State *continued*

Peabody announced in June that is has entered the final phase of project development for Prairie State and is hoping to begin construction of the plant this fall. Project construction is scheduled for four years. The facility will be among the cleanest U.S. coal-fueled plants, with as little as one-fifth the regulated emissions rates of existing U.S. power plants. Its carbon dioxide emissions rate would be approximately 15% lower than the typical U.S. coal plant.

The announcement of AMP-Ohio's participation comes not long after two other partners, Wisconsin Public Power Inc. and CMS Energy Corp., withdrew from involvement.

AMP-Ohio is also seeking to develop its own coal-fired capacity. The company filed permit applications in May for a proposed 1,000-MW coal plant in Meigs County, Ohio. AMP-Ohio has said that it hopes to begin operation of the first unit at the plant in 2012 and the second in 2013. AMP-Ohio spokesman Kent Carson said the company's participation in Prairie State will not impact the Meigs County project. "One of the attractive aspects of Prairie State is that it is in the Midwest ISO, while the new plant we're looking to build is in the PJM Interconnection LLC, so we like the idea of adding capacity in both areas," said Carson, who noted that AMP-Ohio has members in both MISO and PJM.

Gerken noted in a July 2 press statement that AMP-Ohio is also exploring other potential capacity additions. "While we continue our efforts to site our approximately 1,000-MW coal-fired American Municipal Power Generating Station in Meigs County, Ohio, we also are planning several additional hydroelectric generation facilities and exploring the possibility of adding additional wind and natural gas generation to our portfolio," Gerken said. "All the while, we are aggressively exploring opportunities to generate — or purchase — the power that drives our members' and their customers' economic success."

COMPANIES REFERENCED IN THIS ARTICLE:

American Municipal Power Ohio	
CMS Energy Corp.	CMS
Illinois Municipal Electric Agency	
Indiana Municipal Power Agency	
Kentucky Municipal Power Agency	
Midwest ISO	
Peabody Energy Corp.	BTU
PJM Interconnection LLC	
Wisconsin Public Power Inc.	

E-mail this story.

Florida munis halt coal plant *continued*

The decision comes less than a month after the Florida Public Service Commission unanimously rejected FPL Group Inc. subsidiary Florida Power & Light Co.'s proposal to construct the 1,960-MW Glades Power Park, a decision that won praise from Florida Gov. Charlie Crist, who called for the cancellation of the coal-fired projects in his first State of the State speech in May.

Rather than pushing forward at the PSC, Lawson said the power agencies would instead join Crist at an upcoming summit on global climate change planned for mid-July.

"We look forward to the Florida Climate Change Summit this month hosted by Gov. Charlie Crist," Lawson said. "We are eager to further discuss workable solutions to meet the energy demands of Florida's citizens."

The utilities had studied a variety of possible coal supply options for the plant, and most recently had been leaning toward using a blend of South American coal and petroleum coke at Taylor, saying that combination would likely provide the lowest production costs. The utilities had also said that Central Appalachia and Powder River Basin coal could have been an option for the plant, which was expected to consume up to 2.9 million tons of solid fuel annually.

Up until July 3, the backers had been steadily moving forward with the project, which could have added much-desired fuel diversity to the state's power generation portfolio, heavily weighted toward natural gas. One recent development included the filing of a site certification application with the Florida Department of Environmental Protection on May 25. However, the utilities were also facing regulatory delays after discovering that they had overestimated the economic savings the facility would produce, a revelation that forced the utilities and the PSC to reopen the record for further discovery.

The Florida Municipal Power Agency said at the time that the project remained economically viable.

COMPANIES REFERENCED IN THIS ARTICLE:

Florida Municipal Power Agency	
City of Tallahassee	
Florida Power & Light Co.	
FPL Group Inc.	FPL
JEA	
Reedy Creek Improvement District	

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This Week's Generator Profile

Reliant Energy Inc. - Operating

Plant Name	State	Fuel	Technology	Nameplate Capacity MW	Operating Capacity '05	Operating Capacity '04	Capacity Factor '05	Heat Rate '05	Fuel Cost / MWh '05	Non-Fuel O&M / MWh '05
OPERATING COMPANY - Reliant Energy Mid-Atlantic Holdings LLC										
Blossburg	PA	Gas	Combustion Turbine	24	26	26	NA	NA	NA	NA
Conemaugh	PA	Coal	Steam Turbine: Boiler	1,872.0	279.7	279.7	86.89	9,539	13.46	4.93
Conemaugh IC	PA	Oil	Internal Combustion	11	2	2	0.19	10,879	85.46	NM
Hamilton	PA	Oil	Combustion Turbine	20	26	26	NA	NA	NA	NA
Hunterstown	PA	Oil	Combustion Turbine	60	81	81	NA	NA	NA	NA
Keystone	PA	Coal	Steam Turbine: Boiler	1,872	283	283	90.47	9,565	15.50	3.43
Keystone IC	PA	Oil	Internal Combustion	12	2	2	1.42	10,406	111.20	9.12
Mountain	PA	Oil	Combustion Turbine	54	54	54	NA	NA	NA	NA
Orrtanna	PA	Oil	Combustion Turbine	27	26	26	NA	NA	NA	NA
Portland	PA	Coal	Steam Turbine: Boiler	427	401	401	61.75	9,845	17.80	6.66
Portland CT	PA	Gas	Combustion Turbine	194	198	198	3.33	13,951	123.53	25.91
Shawnee CT	PA	Oil	Combustion Turbine	20	26	26	NA	NA	NA	NA
Shawville	PA	Coal	Steam Turbine: Boiler	626	618	618	59.11	11,007	17.74	6.66
Shawville IC	PA	Oil	Internal Combustion	6	6	6	NM	NA	NA	NA
Titus	PA	Coal	Steam Turbine: Boiler	225	249	249	58.37	10,627	18.55	9.38
Titus CT	PA	Oil	Combustion Turbine	36	39	39	0.23	16,875	147.50	277.58
Tolna	PA	Oil	Combustion Turbine	54	54	54	NA	NA	NA	NA
Warren CT	PA	Gas	Combustion Turbine	53	NA	79	NA	NA	NA	NA
Gilbert CC	NJ	Oil	Combined Cycle	351	384	384	3.67	10,634	84.52	50.08
Gilbert CT	NJ	Oil	Combustion Turbine	257	307	307	0.89	14,075	129.28	63.45
Glen Gardner	NJ	Gas	Combustion Turbine	160	208	208	NA	NA	NA	NA
Sayreville CT	NJ	Gas	Combustion Turbine	212	304	304	0.44	16,167	132.43	80.54
Werner	NJ	Oil	Combustion Turbine	212	292	292	0.36	18,819	179.56	99.59
OPERATING COMPANY - Reliant Energy Power Generation Inc.										
Reliant Energy Channelview	TX	Gas	Combined Cycle	918	856	856	68.38	10,252	77.88	2.01
Sabine Cogeneration	TX	Gas	Combined Cycle	101	51	51	NA	NA	NA	NA
Hunterstown CC	PA	Gas	Combined Cycle	898	810	810	10.07	8,218	76.71	13.23
Bighorn CC	NV	Gas	Combined Cycle	688	555	555	60.64	7,363	50.24	2.99
Choctaw County	MS	Gas	Combined Cycle	NA	726	726	NA	NA	NA	NA
Reliant Energy Aurora	IL	Gas	Combustion Turbine	1,275	995	995	3.53	10,552	87.64	13.63
Reliant Energy Shelby County	IL	Gas	Combustion Turbine	483	473	473	1.58	9,841	78.93	33.82
Indian River ST	FL	Oil	Steam Turbine: Boiler	609	619	619	12.17	12,041	90.02	21.18
Reliant Energy Osceola	FL	Gas	Combustion Turbine	600	534	534	8.78	11,407	95.52	6.57
Coolwater Generating Station	CA	Gas	Steam Turbine: Boiler	147	146	146	2.28	9,739	NA	NA
Coolwater Generating Station CC	CA	Gas	Combined Cycle	580	462	462	9.02	10,475	74.68	21.06

This Week's Generator Profile *continued*

Plant Name	State	Fuel	Technology	Nameplate Capacity MW	Operating Capacity '05	Operating Capacity '04	Capacity Factor '05	Heat Rate '05	Fuel Cost / MWh '05	Non-Fuel O&M / MWh '05
Ellwood Generating Station	CA	Gas	Combustion Turbine	58	54	54	NA	NA	NA	NA
Etiwanda Generating Station	CA	Gas	Steam Turbine: Boiler	666	640	640	12.92	11,957	94.15	25.33
Mandalay Generating Station	CA	Gas	Steam Turbine: Boiler	436	430	430	9.26	10,466	75.64	35.60
Mandalay Generating Station CT	CA	Gas	Combustion Turbine	NA	130	130	0.05	17,098	NA	NA
Ormond Beach Generating Station	CA	Gas	Steam Turbine: Boiler	1,612	1,516	1,516	3.88	11,511	81.47	78.35
OPERATING COMPANY - Orion Power Holdings, Inc.										
Brunot Island	PA	Oil	Combustion Turbine	77	66	66	NM	NA	NA	NA
Brunot Island CC	PA	Gas	Combined Cycle	341	311	311	0.30	22,727	NM	NM
Cheswick	PA	Coal	Steam Turbine: Boiler	637	588	588	56.10	10,065	17.56	6.27
Elrama	PA	Coal	Steam Turbine: Boiler	510	487	487	37.32	11,726	20.95	10.60
New Castle	PA	Coal	Steam Turbine: Boiler	348	333	333	45.08	11,479	19.48	8.07
New Castle IC	PA	Oil	Internal Combustion	6	5	5	0.11	11,445	NA	NA
Avon Lake	OH	Coal	Steam Turbine: Boiler	841	739	739	54.71	10,023	15.77	6.76
Avon Lake CT	OH	Oil	Combustion Turbine	29	29	29	0.38	23,663	235.13	201.33
Niles	OH	Coal	Steam Turbine: Boiler	250	216	216	53.64	11,574	17.03	11.55
Niles CT	OH	Oil	Combustion Turbine	35	30	30	NM	NA	NA	NA
OPERATING COMPANY - Other										
Seward Waste Coal	PA	Coal	Steam Turbine: Boiler	585	521	521	61.20	10,776	18.52	14.29

SNL includes in the above list all projects in the given region that have had a status update in the last six months.

Source: SNL Energy