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TVA votes to complete reactor at long-debated Bellefonte nuclear project

by Wayne Barber

After hearing from a deeply divided public, the Tennessee Valley Authority board voted unanimously Aug. 18 to pursue completion of one of two never-finished reactors at the Bellefonte Nuclear plant in Jackson County, Ala.

TVA board member Mike Duncan did amend the proposal to stipulate that any actual construction would not start at Bellefonte until the utility has loaded fuel at its nearly finished Watts Bar 2 plant in Tennessee. As with Bellefonte, construction was suspended years ago at Watts Bar 2. The amendment, included without debate, is meant to make TVA comply with its "one-at-a-time" nuclear construction strategy.

If everything goes well, including issuance of an operating license from the U.S. Nuclear Regulatory Commission, TVA could bring a completed 1,260-MW reactor into commercial operation at Bellefonte between 2018 and 2020 at an estimated cost of $4.9 billion. TVA COO Bill McCollum said completing unit 1 at Bellefonte would permit TVA to use about $1.9 billion worth of existing infrastructure.

At peak employment, about 2,800 workers would be involved in completing Bellefonte 1. New steam generators and various other upgrades would be made, officials said. TVA also said the refurbished plant would meet safety requirements for existing plants.

Bellefonte 1 would be revived under NRC's old "two-step" licensing process, unlike the new process that combines construction

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Ga. regulators approve H2'10 construction spending for Vogtle nuke

by Matthew Bandyk

The Georgia Public Service Commission on Aug. 16 approved Georgia Power Co.'s spending for its proposed Vogtle nuclear power plant expansion for the last six months of 2010. The order approving the construction spending will be made public by the commission no later than Aug. 18 or 19, PSC attorney Jeffrey Stair said.

The spending was related to a semiannual construction report that the Southern Co. subsidiary filed in February, the fourth such filing for the Vogtle project so far, Georgia Power spokeswoman Christy Ihrig said. The fifth request for approval of construction spending will be filed at the end of this month, Ihrig said.

While the exact amount of spending approved by the commission is confidential, the company had spent $1.3 billion on the project through the end of 2010, she said.

The proposed new units, each with capacity of about 1,100 MW, would be two of the first new nuclear units built in decades. But the project has faced claims from an engineer hired by the Georgia PSC that the construction could run over its certified

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EPA, North Dakota in standoff over pollution controls on coal plants

by Matthew Bandyk

In a move that opponents have dubbed a "federal takeover," the U.S. Environmental Protection Agency is expected to approve a plan on Aug. 18 that would force — over the wishes of state regulators — coal plants in North Dakota to spend hundreds of millions of dollars on pollution-scrubbing systems.

The outcry over the EPA's plan to issue a regional haze plan for North Dakota has joined coal producers, electric cooperatives and labor groups into a coalition of opposition. "The federal government would require expensive technology — nearly $700 million in unnecessary spending that couldn't help but affect ratepayers in a difficult economy," Partners for Affordable Energy said on a website created to counter the EPA's efforts.

The group supports coal-fired generation and counts among its supporters the Minnkota Power Cooperative Inc., which owns a stake in the coal-fired Milton R. Young power plant, and Basin Electric Power Cooperative, which owns the coal-fired Leland Olds power plant. Several labor

groups, including the North Dakota AFL-CIO and the North Dakota State Building & Construction Trades Council, also are part of the coalition assembled by Partners for Affordable Energy.

The resistance to the EPA in North Dakota has another unlikely ally. On July 13, U.S. Sen. Al Franken, D-Minn., along with Rep. Collin Peterson, D-Minn., sent EPA Deputy Administrator Robert Perciasepe a letter asking that the agency be "mindful" of the impacts that installing selective catalytic reduction systems at North Dakota coal plants could have on Minnesota ratepayers.

"Our constituents are concerned about possible increases in electricity rates, without proven health or environmental benefit, as a result of these requirements," the lawmakers said in the letter.

The Milton Young plant sells much of its power to electric cooperatives in Minnesota. Many of these cooperatives are also supporting the campaign against the EPA plan.

"Our average retail rates have almost doubled in the last eight years, due to rising wholesale power costs," said North Star Electric Cooperative Inc. Finance Manager Ann Ellis. "This latest EPA issue will add salt to a big wound, and it appears it could add another couple of cents per kWh to the rate."

The environmental groups that pushed for the EPA to crack down on North Dakota air emissions, meanwhile, have expressed disappointment with Franken's stance. "The unfortunate thing is a lot of misinformation is being swung around inside the Beltway," WildEarth Guardians Climate and Energy Program Director Jeremy Nichols said. "Franken unfortunately wanted to jump on the bandwagon."

But the debate over North Dakota's coal plants does not revolve solely around electric rates. Opponents of the EPA plan have also accused the federal regulators of ignoring "local knowledge" at the expense of technical feasibility, arguments that may reappear if the EPA plan is legally challenged by the state.

Debate over feasibility

The standoff between North Dakota and the EPA began in 2010 when the environmental group WildEarth Guardians petitioned the EPA to close a "clean air loophole" by forcing North Dakota's air quality regulations to come into compliance with federal standards. The group sued the EPA, demanding that it issue a plan to control regional haze from emissions sources in the state.

Previously, the National Parks Conservation Association and other environmental groups criticized the North Dakota Department of Health's draft regional haze plan for requiring only "lenient" emissions reductions from the state's coal plants, according to a December 2009 statement.

The EPA responded to the groups' protests. A June 6 settlement in the U.S. District Court for the District of Colorado between the EPA and WildEarth Guardians said the agency would either approve North Dakota's state implementation plan for regional haze requirements or promulgate its own federal implementation plan.

The EPA chose to propose its own federal implementation plan that it believes will reduce NOx emissions by 12,000 tons at one unit at the Leland Olds plant and two units at the Milton Young station through the installation of SCR technology, according to EPA Region 8 Air Quality Unit Chief Monica Morales. The EPA's regional administrator will likely sign off on the plan Aug. 18 with a notice in the Federal Register, she said.

But the EPA's plan is at odds with the conclusions of the North Dakota Department of Health. "EPA has an ongoing disagreement with North Dakota concerning the appropriate technology needed to comply with the federal regional haze regulations for nitrogen oxides," Morales said.

The North Dakota department determined in a November 2010 findings of fact that SCR should not be considered "best available control technology" for the purposes of complying with the federal standards.

Instead, the state regulators said they want Minnkota Power and Basin Electric to install selective noncatalytic reduction systems at their plants, North Dakota Department of Health Senior Environmental Engineer Tom Bachman said.

"We have some issues with the technical feasibility" of SCR, he said. The findings of fact concluded that SCR is not "available" as a technology to be considered because it has not been proven to work with facilities that burn North Dakota lignite coal. The state regulators are concerned that the high sodium content of this specific type of coal might prove to be unworkable with the catalyst component that these pollution control systems use to absorb pollutants.

"Sodium in the coal can plug the holes of the catalyst and even poison the catalyst," Bachman said. According to the findings of fact, two potential SCR catalyst vendors, CERAM Environmental Inc. and Haldor Topsoe Inc., have refused to provide "life guarantees" for their catalysts in the case of North Dakota lignite coal and would require up to one year of pilot testing before they can offer this guarantee.

The plant owners are rallying behind these findings as evidence that the state plan is preferable to the EPA plan. "The SCR is unproven to work on North Dakota lignite coal," Minnkota Power spokesman Kevin Fee said. The company is willing to install [selective noncatalytic reduction] technology instead. "We're definitely backing the state plan," he said.

Basin Electric also supports selective noncatalytic reduction over SCR. Company spokesman Daryl Hill said the potential problems with lignite coal and SCR is an example of how the "local knowledge" of state regulators should hold sway over the EPA's. "The health department knows very well the types of plants that are here and knows the technology that will work for reducing nitrogen oxide with lignite," he said.

Partners for Affordable Energy, which includes the Lignite Energy Council as a supporter, takes a stronger position. Spokesman Steve Van Dyke said that SCRs are proven not to work on coal plants like Milton Young and Leland Olds. He pointed to testing performed by the Energy & Environmental Research Center in Grand Forks, N.D., a group affiliated with the University of North Dakota. In an Aug. 5 letter to the *Bismarck Tribune*, several members of the research center wrote that a pilot study of North Dakota lignite coal it performed with the U.S. Department of Energy, the Electric Power Research Institute and catalyst vendors concluded that "installing an SCR system on a cyclone-fired power plant burning high-sodium North Dakota lignite will simply not work."

But the EPA disagreed with these results. "EPA's preliminary determination is that a more effective technology for removing nitrogen oxides, SCR, is technically feasible and cost effective," Morales said. "Although this represents our current view, if new information is presented to us during the comment period or before we make a final decision we could change direction on our preliminary determination," she said. A comment period will follow the approval of the new regional haze plan.

Debate over cost, benefits

But technical feasibility is not the only reason the North Dakota Department of Health disagrees with the EPA. Bachman said the

department's state implementation plan also found that selective noncatalytic reduction should be considered best achievable control technology "based on excessive cost of SCR and little visibility improvement over [selective noncatalytic reduction]."

According to Basin Electric spokeswoman Mary Klecker-Green, both Basin Electric and Minnkota Power have estimated that the installation of SCRs for both companies would cost about $700 million more than the $691 million plan proposed by the state regulators.

Milton Young's share of the additional cost would be about $500 million, and the SCRs would lead to a 20% increase in rates for members of the cooperative, Fee said. Square Butte Electric Cooperative Inc. also owns a stake in the Milton Young plant.

Modeling by the North Dakota department concluded that the visibility benefits from installing SCR instead of selective noncatalytic reduction would not be discernible to the human eye, Klecker-Green said.

But the department's claims about the differences between SCR and selective noncatalytic reduction are "incorrect," according to National Parks Conservation Association attorney Stephanie Kodish. The percentage of pollution that can be reduced by selective noncatalytic reduction — about 20% to 25% of NOx emissions — are "dwarfed" by the reductions possible from SCR systems, which can control about 90%, she said.

According to Kodish, the EPA plan is an "adequate" solution to the regional haze problems her group identified in 2009.

In response to the concern about the costs to ratepayers posed by the EPA plan expressed by Franken and others, representatives of several groups, including the Sierra Club, the National Parks Conservation Association and WildEarth Guardians, sent a letter to the EPA answering the claims. "Regarding costs, for example EPA, among others, has demonstrated that Minnkota's estimates are 'inflated and unreasonable,'" the letter said. "Depending on the configuration of the system, a more accurate estimate of capital investment would be 30-50% less than $500 million."

Once the EPA approves the plan, the debate may continue well past the comment period. According to Van Dyke, the plan will be challenged in a lawsuit filed by the state, and the North Dakota Legislature has already set aside money for this purpose.

COMPANIES REFERENCED IN THIS ARTICLE:

Basin Electric Power Cooperative

Minnkota Power Cooperative Inc.

North Star Electric Cooperative Inc.

Square Butte Electric Cooperative Inc.

Industry Document: Findings of Fact

Industry Document: Letter to Robert Perciasepe

Industry Document: Consent Decree

Industry Document: Letter from Al Franken and Collin Peterson

Industry Document: Parks and Conservation Groups Urge North Dakota to Protect National Parks and Forests from Coal Plant Haze

Industry Document: WildEarth Guardians Takes Aim at North Dakota Clean Air Loopholes

E-mail this story.

EPA delays decision on regional haze plan for North Dakota

by Matthew Bandyk

The U.S. Environmental Protection Agency's deadline for approving a controversial regional haze plan for North Dakota has been pushed to Sept. 1, EPA Region 8 Air Quality Unit Chief Monica Morales said Aug. 18.

The EPA's proposal would force selective catalytic reduction systems to be installed at the Milton R. Young and Leland Olds coal-fired plants, owned by Minnkota Power Cooperative Inc. and Basin Electric Power Cooperative, respectively, to control NOx emissions. Both companies have publicly opposed the plan, arguing that it would

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force $700 million in extra spending and lead to rate increases for electricity customers in the region.

Instead, Minnkota Power and Basin Electric favor the state implementation plan proposed by the North Dakota Department of Health. This plan would require the installation of less expensive selective noncatalytic reduction systems at the plants.

But earlier this year, the EPA notified North Dakota regulators that it would overrule the state implementation plan by approving its own plan that favored SCR over selective noncatalytic reduction.

The previous deadline for approval of the EPA plan was Aug. 18. But the EPA told the North Dakota department that it needed more time "to cross some T's and dot some I's," North Dakota Department of Health Senior Environmental Engineer Tom Bachman said Aug. 18.

A public comment period will follow the EPA's approval.

Square Butte Electric Cooperative Inc. also owns a stake in the Milton Young plant.

COMPANIES REFERENCED IN THIS ARTICLE:

Basin Electric Power Cooperative

Minnkota Power Cooperative Inc.

Square Butte Electric Cooperative Inc.

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CRS: Is EPA's regulation of coal plants a 'train wreck' coming?

by Kathleen Hart

In a report considering whether there is a "train wreck" coming for coal-fired power in the United States from numerous new rules proposed by the EPA, the Congressional Research Service found that the answer depends on the individual plant.

"Older, smaller, less efficient units already face a train wreck. In 2010, 48 of them with a combined capacity of 12 GW were retired," the Congressional Research Service said in an Aug. 8 report titled "EPA's Regulation of Coal-Fired Power: Is a 'Train Wreck' Coming?"

The CRS noted that one source "identifies 149 coal-fired units with a combined capacity of 19.7 GW whose retirement has been announced or implemented in the past few years. In recent weeks, as utilities weigh the cost of retrofitting and operating their older units, more retirements have been announced." However, the report concluded that this does not mean newer coal plants that have invested in pollution controls over the years will be shuttered.

Most coal plants built after 1970 already comply with many of the proposed EPA rules or "can do so with modest modifications to their pollution control equipment," the CRS said, adding that a "train wreck" for this group of plants seems unlikely.

However, the CRS noted that "between the two ends of the spectrum are facilities that are efficient enough or play a sufficiently vital role in meeting regional demand that the economics likely would justify their retrofit. For these facilities, the key questions are whether there will be sufficient time to act, and whether the reliability of the electric grid will be affected as they are taken off-line for modification."

Noting that it is hard to make generalizations about timing and system reliability issues, the report pointed to several utilities that have stated they will have trouble meeting the deadlines for new EPA regulations. Southern Co. Chairman, President and CEO Thomas Fanning said in congressional testimony in April that the "reliability of the nation's electric generating system is at risk because of the number of new rules and regulations applicable to power plants. The stringency of these regulations, the lack of flexibility likely to be provided within these regulations, and, above all, the compliance schedules that will be required put reliability at risk."

In particular, Fanning told Congress that accelerated plant retirements and shutdowns "triggered by the Utility MACT rule will cause reserve capacity to plummet, increasing the likelihood and severity of service disruptions."

The CRS also highlighted an announcement in June by American Electric Power Co. Inc. Chairman and CEO Michael Morris that nearly 25% of the company's coal-fired generation would be retired.

"We support regulations that achieve long-term environmental benefits while protecting customers, the economy and the reliability of the electric grid, but the cumulative impacts of the EPA's current regulatory path have been vastly underestimated, particularly in Midwest states dependent on coal to fuel their economies," Morris said in a news release. "We have worked for months to develop a compliance plan that will mitigate the impact of these rules for our customers and preserve jobs, but because of the unrealistic compliance timelines in the EPA proposals, we will have to prematurely shut down nearly 25% of our current coal-fueled generating capacity, cut hundreds of good power plant jobs, and invest billions of dollars in capital to retire, retrofit and replace coal-fueled power plants."

However, the CRS report noted that studies sponsored by industry groups such as the Edison Electric Institute and the North American Electric Reliability Corp. "were written before EPA proposed most of the rules whose impacts they analyze, and they assumed that the rules would impose more stringent requirements than EPA proposed in many cases."

Of the EPA regulations proposed so far, the utility MACT rule, which will set standards for power plant emissions of mercury and other hazardous air pollutants, "appears to be the most expensive. EPA's analysis concluded that it will impose annual costs of $10 billion to $11 billion annually," the CRS report said.

Sen. James Inhofe, R-Okla., ranking Republican on the Senate Environment and Public Works Committee, raised concerns that the EPA exaggerated the extent of its collaboration with FERC to assess how the utility maximum achievable control technology, or utility MACT, rule could affect electric reliability.

"It is critical that EPA clearly display the specific level of outreach and consultation that is stated in the Utility Air Toxics Rule preamble so that we can better understand the extent to which reliability concerns were evaluated," Inhofe wrote in an Aug. 16 letter to EPA Administrator Lisa Jackson. "Given the scope of this proposal, and the nearly $11 billion annual costs that EPA estimates from this one rule, American citizens quite literally cannot afford to have you get this wrong."

The CRS said other rules the industry expected to impose major costs "now appear less likely to do so. The Cooling Water Intake rule, for example, proposes a less costly, more flexible regulatory option than [Edison Electric Institute] and NERC anticipated."

In comments filed with the EPA on Aug. 17, EEI voiced support for some elements of the EPA's proposed rule on cooling water intake

structures at existing power plants but urged the agency to modify parts that it considers unnecessary, infeasible and too costly.

COMPANIES REFERENCED IN THIS ARTICLE:

American Electric Power Co. Inc. **AEP**

Edison Electric Institute

Southern Co. **SO**

Industry Document: EPA's Regulation of Coal-Fired Power: Is a "Train Wreck" Coming?

E-mail this story.

Public power groups call Moody's ratings changes inappropriately specialized

by Kerry Bleskan

Public power interest groups protested proposed changes to Moody's ratings on Aug. 15, saying the changes could "unfairly isolate public power in the minds of investors."

The charge came in joint comments from the American Public Power Association, which represents more than 2,000 publicly owned electric utilities, and the Large Public Power Council, which represents 25 of the largest publicly owned power systems.

Public power utilities are more like other types of municipal entities than investor-owned or cooperative utilities, the two groups said. "We recognize the need to continually review historical analytical approaches and explore new methodologies that may provide more accurate and meaningful information for investors and issuers alike," they said. "We can appreciate a desire to compare public power utilities to other electric utilities such as investor owned utilities and electric cooperatives. However, investors will be better served by comparing public power to the other enterprises in which they invest — such as the broader base of municipal revenue bonds. Creating a unique methodology for public power has as much potential to confuse as to inform the investor."

On June 17, Moody's issued proposed changes to three metrics and gave interested parties 60 days to comment. The rating agency said the changes would allow for more direct comparison of different types of public power utilities.

In effect, Moody's is using some of the proposed changes to adjust public power utilities' ratings, said Jim Fuller, senior vice president and CFO of the Municipal Electric Authority of Georgia and a representative of the LPPC's tax and finance committee. When Moody's recently downgraded some Florida Municipal Power Agency bonds, Fuller said, the rating agency mentioned liquidity concerns that are "on point with some of the proposed new metrics."

Possible changes to debt, cash ratios

In Moody's proposed new adjusted debt service ratio metric, the surplus revenue payments — called transfer payments that utilities make to their municipal governments — would be treated as operating expenses. When utilities finance assets off their balance sheet using joint power agency contracts, those obligations would be treated like debt and incorporated into the metric using a new "fixed obligation coverage charge ratio."

Because there is wide variety in public utilities' approaches to cash reserves, Moody's proposed to adjust the cash-on-hand ratio by subtracting collateral posting requirements and accounting for the difference between actual debt service reserve funding and fully funded debt service reserve. "Additionally, Moody's will evaluate external liquidity sources such as bank lines of credit, but will only include them as available cash and investments if they are undrawn and meet our more stringent credit standards," the firm said.

Public power groups: Those factors already considered

Transfer payments, the "take or pay" contracts associated with joint power agencies, and the funding of reserves are already taken into account when determining a public utility's credit rating, "just not as a component of the key metrics," APPA and LPPC said. "Moody's should continue its practice of relying on a mixture of quantitative and qualitative assessments, and resist the impulse to fine-tune key metrics only as they apply to the public power sector. The key metrics should remain the same across the municipal finance industry," the groups said.

Moody's said it wants to consider transfer payments an operating expense because, "while the transfers come after debt service in the legal flow of funds, practically the transfer is a requirement and in many cases the transfer is made on a monthly basis." The utility groups said the transfer payments are a flexible tool and, as far as either group knows, debt service payments are always prioritized over transfer payments. "Transfer payments serve as a buffer that can be reduced in difficult times as opposed to a requirement that must be met prior to debt service," APPA and LPPC said. "Given this legal structure, the existing, traditional debt service coverage calculation should serve as the key coverage metric for public power and other revenue-based credits that make governmental transfers."

The existing metric is the norm for the industry, the groups said, used by public power utilities, investors, analysts and other rating agencies. "Moody's proposed adjusted debt service coverage ratio would produce materially different results from those calculated by the rest of the industry and could be an inaccurate representation of the funds that are legally available and mandated to meet debt service obligations," the utility groups said.

No 'best' debt service funding level

The proposed change to the cash-on-hand metric mixes up liquid assets and debt service reserves and muddies the metric's usefulness as a measure of liquidity, APPA and LPPC said. "Moody's could address debt service reserves through a separate metric or in a qualitative assessment as part of its credit rating. Including information on debt service reserves as part of a liquidity measure, however, is inappropriate. … Moody's proposed adjusted days cash on hand ratio seemingly values non-restricted cash and investments as equally available to cover cash flow variability as monies held in a highly restricted debt service reserve. Neither issuers nor investors view debt service reserve funds as readily and routinely available to be used for debt service payments, let alone to be used for operating payments," the utility groups said.

Flexibility also is key in deciding levels of debt service, APPA and LPPC said, and appropriately varies from utility to utility. "There is no 'proper' or 'best' level of funding of debt service reserves," they said. "The proposed adjusted days cash on hand ratio will likely encourage utilities to increase the level of funding of debt service reserves, and this may not be the best decision for some utilities and their ratepayers."

Carrying reserves can cost as much as 4% to 5% annually, for instance. Some highly rated utilities are able to leverage that strong rating to enable lower reserve requirements. "The benefit could disappear if Moody's expects all utilities to carry large, virtually inaccessible, reserve funds," they said. "Moody's should continue to use the standard days cash on hand ratio, which is the measure of liquidity used throughout the municipal finance industry, and allow public power managers the flexibility to determine the most appropriate reserve funding for the utility."

COMPANIES REFERENCED IN THIS ARTICLE:

Florida Municipal Power Agency

Municipal Electric Authority of Georgia

Industry Document: Request for Comment: Moody's Considers Use of New Financial Metrics In U.S. Public Power Electric Utility Rating Methodology

E-mail this story.

Exelon's Rowe: Nuclear power is business, not 'religion'

by Wayne Barber

Exelon Corp. Chairman and CEO John Rowe, whose company has the largest nuclear fleet in the United States, cautioned the American Nuclear Society on Aug. 15 that new nuclear has become less economic over the past two years.

Nuclear is vital if the nation is to have reliable baseload generation and still tackle global warming, Rowe told the gathering in Hollywood, Fla., "but we must keep our hopes for new nuclear generation harnessed to facts. Nuclear power is a business and not a religion."

"Here at home, support for nuclear power is waning and although still relatively strong, recent polls show nearly a 20% drop in support for nuclear power from pre-Fukushima levels of support," Rowe said, referring to the nuclear plant disaster that occurred in Japan in March following an earthquake and tsunami. "While not Chernobyl, Fukushima is a tragic event and the worst to hit the nuclear industry outside Russia. I would solemnly ask all of you to remember Fukushima in your jobs every day," Rowe said.

In a speech, Rowe described four criteria that he said must be met before a "nuclear renaissance" can happen. While the industry now has one of those criteria, the right passive reactor designs, it still needs a workable solution to the waste problem; increased demand for electricity; and stable, higher prices for power to make it economical to build a new nuclear plant.

Rowe has been very involved in the nuclear waste issue. He has served on a blue ribbon advisory panel to the U.S. Department of Energy that issued a draft report this summer that called for creating a quasi-governmental agency to oversee spent nuclear fuel.

The Blue Ribbon Commission on America's Nuclear Future recently released a schedule of public meetings during September and October to take public comment on the draft report.

"As you may know, I am nearing the end of a four-decade career, most of which has been spent in the utility and nuclear industries," Rowe said. "Having seen the good and the bad, I still have never met a nuclear plant I don't like. I am a 'nuke' through and through. But — we nukes are best served by cold-blooded analysis."

A combination of energy efficiency and increased generation through uprates both remain economic options for Exelon, Rowe said. But other much-discussed power options can get pricey.

Wind looks attractive with a carbon price of between $80 and $120 per tonne, according to 2010 figures, Rowe said. New nuclear needs a carbon price of $100 per tonne to break even. While solar costs are down, it still comes in at about $450 per tonne, and a proposed coal plant "without carbon capture and sequestration in Illinois requires $500/tonne to be economic," Rowe said.

Federal subsidies help but do not remake the overall economics, he said.

In addition, electricity demand is not expected to return to 2008 levels until the middle of the decade, and major U.S. natural gas finds have changed the energy landscape.

The American Nuclear Society is a nonprofit, international scientific and educational organization.

COMPANY REFERENCED IN THIS ARTICLE:

Exelon Corp. **EXC**

PR: Exelon CEO Says Nation Needs Nuclear Power, But Cites Economic Challenges to New Build

Misc: Exelon Corp. (EXC)

Industry Document: BRC Announces its Public Meetings for Input on Draft Report

E-mail this story.

NRC cites Prairie Island nuke for battery charger problems

by Matthew Bandyk

The Nuclear Regulatory Commission issued a violation of low to moderate safety significance against Xcel Energy Inc.'s Prairie Island nuclear plant in Minnesota, the NRC said Aug. 17.

During routine inspections, NRC inspectors discovered that the safety-related battery chargers at unit 1 of the plant had the potential to perform incorrectly under certain scenarios. The batteries are needed to provide alternate power to remotely operate plant safety equipment.

The regulators characterized the finding as "white" in their four-tiered color-coded system. White implies "low to moderate" safety significance and is above green but below yellow and red in terms of significance, the NRC said.

Site personnel discovered in the mid-1990s that the chargers might not start automatically in some conditions, Xcel Energy spokeswoman Mary Sandok said. Manual procedures were put in place to require the restarting of the chargers, and these procedures were updated in 2010, she said.

The NRC said in the statement that Xcel Energy has taken actions to address the potential malfunction. The need for the manual procedures has been removed by the installation of a new model of battery chargers that are not susceptible to the malfunction, Sandok said. These chargers were installed in May at unit 1, she said, and will be installed at unit 2 during the spring 2012 outage.

The company is reviewing the NRC's action and has until Sept. 16 to contest it, Prairie Island Site Vice President Mark Schimmel said in an emailed statement.

The Fukushima Dai-ichi nuclear disaster in Japan brought to the forefront the issue of batteries at nuclear plants and the role they play in case of a loss of power. The Nuclear Energy Institute, the Institute of Nuclear Power Operations and the Electric Power Research Institute have launched an investigation into "lessons learned" from the Fukushima incident and have said nuclear plants may need to extend the lives of their emergency batteries as part of these lessons.

NRC Chairman Gregory Jaczko also has said the regulators may need to revisit rules on station blackout and potentially increase the amount of time plants can run without off-site power.

The NRC granted Prairie Island a 20-year extension of the operating licenses for both units in June.

COMPANY REFERENCED IN THIS ARTICLE:

Xcel Energy Inc. **XEL**

Industry Document: NRC Cites Prairie Island Unit 1 Nuclear Plant for an Issue Involving Battery Chargers

E-mail this story.

Tritium detected in Connecticut River near Vermont Yankee nuke

by Matthew Bandyk

Separate tests by Entergy Corp. and the Vermont Department of Health reached different results about the level of tritium detected in the Connecticut River near the Vermont Yankee nuclear plant.

The department said Aug. 17 that it discovered tritium contamination in the river after tracking a plume of tritium-contaminated groundwater that had been moving into the river from a shoreline near Entergy's plant. Water samples from July 18 and July 25 measured tritium at 534 and 611 picocuries per liter, which is just above the lower limit of what is considered a detectable amount, the department said in a statement.

On Aug. 18, Entergy Nuclear Vermont Yankee LLC spokesman Laurence Smith said testing by Entergy's own laboratory of the same samples show levels of tritium below that lower limit.

"We are very interested in working with the state to understand the discrepancy in the test results," Smith said. "As such, we have proposed to the state that we send both our samples and theirs to an independent third-party laboratory for an additional round of testing."

But the Vermont Department of Health does not see Entergy's proposal for third-party testing as necessary, department Radiological and Toxicological Sciences Program Chief Bill Irwin said Aug. 18. "We stand by our laboratory results," he said.

According to Irwin, the samples tested by Entergy were not identical to the department's samples. "We did not actually count the same containers of river water. We took samples from the same location in the river," he said. The differing results from the two laboratories are not surprising, given tritium's long radioactive half-life, Irwin said

Vermont Gov. Peter Shumlin asked the department to begin obtaining weekly samples of water from the Connecticut River. That request was prompted by the Aug. 2 discovery of strontium-90,

another type of radioactive material, in fish nine miles upstream from Vermont Yankee.

Following the finding, the governor also called for an increase in the number of extraction wells to prevent contamination from reaching groundwater supplies. In a statement released Aug. 17, Shumlin said "confirmation that tritium has reached the shoreline of the Connecticut River is further evidence of the immediate need for more extraction wells and increased monitoring of the situation."

Small amounts of tritium were discovered at a monitoring well near the plant in January 2010. Since then, the tritium issue has been cited by Vermont Yankee's numerous opponents as another reason to close the plant.

Entergy has sued the state of Vermont for refusing to renew a state license for Vermont Yankee. Without this license, the plant must shut down after the first quarter of 2012.

COMPANIES REFERENCED IN THIS ARTICLE:

Entergy Corp. ETR

Entergy Nuclear Vermont Yankee LLC

Industry Document: Tritium Detected for First Time at Connecticut River Shoreline

E-mail this story.

Newfoundland counts on Lower Churchill hydro plant to lower greenhouse gas emissions

by Susan Nelson

The province of Newfoundland and Labrador is counting on the proposed 824-MW Lower Churchill Falls hydroelectric project to lower its greenhouse gas emissions.

The reason is not because of the emissions-free hydroelectric power that will be generated but because the project, if approved, will allow the 500-MW Holyrood thermal generating station in Newfoundland, operated by provincial government-owned Nalcor Energy, to be shuttered.

Power generation accounts for 9% of the province's greenhouse gas emissions, which were 9.5 megatonnes in 2009, or 1.4% of Canada's greenhouse gas emissions.

Those figures mean the province has the second-lowest overall greenhouse gas emissions among provinces, according to Newfoundland and Labrador's "Climate Change Action Plan — 2011," released Aug. 16.

In terms of per-capita emissions, Newfoundland and Labrador is in fifth place among the provinces, due to a low population and a large resource-based economy. In fact, greenhouse gas emissions have grown in the province since 1990 by 2.7% because of the growth of the offshore oil industry and other large industries.

Without the Muskrat Falls facility, the first of two generating units to be built as part of the Lower Churchill Falls project, greenhouse gas emissions in the province are projected to increase above 10 megatonnes around 2014.

With Muskrat Falls, greenhouse gas emissions in Newfoundland and Labrador are expected to drop below 10 megatonnes around 2014 and continue back down to its current amount of 9.5 megatonnes around 2017.

The second generating station planned under the Lower Churchill Falls project, the 2,250-MW Gull Island station, might then lower greenhouse gas emissions further in coming years. However, growth in the oil and gas sectors could cause an increase in emissions in the province.

COMPANY REFERENCED IN THIS ARTICLE:

Nalcor Energy

Industry Document: New Action Plans Released on Climate Change and Energy Efficiency

Industry Document: Climate Change Action Plan 2011

E-mail this story.

Enviros lay out case against Sunflower coal permit in Kan. Supreme Court

by Dan Lowrey

Environmental groups are asking the Kansas Supreme Court to revoke an air permit granted by state regulators for an expansion of a coal-fired power plant sought by Sunflower Electric Power Corp.

In a recent brief filed with the state supreme court, the groups allege the permit issued falls short of the requirements of the Clean Air Act and will not adequately protect human health or the environment. Additionally, the environmental groups claim the permit provides no enforceable limits on nitrogen oxides and sulfur dioxide pollution, and it does not require best available control technology be used at the plant as prescribed by law.

In an Aug. 15 news release, Todd True of Earthjustice said, "Kansans deserve clean energy and clean air. Despite numerous attempts by coal-boosters to push through this project, we believe the permit will not withstand the scrutiny of judicial review.

Earthjustice, on behalf of the Kansas chapter of the Sierra Club, had previously appealed to the Kansas Court of Appeals to have the Kansas Department of Health and Environment's air permit for the proposed 895-MW Holcomb Expansion coal plant declared invalid. But the case was later moved to the Supreme Court.

The Kansas agency issued the air permit for the western Kansas project Dec. 16, 2010, after a contentious review process in which outgoing Kansas Gov. Mark Parkinson publicly denied that he had to speed up the permit's approval.

The groups claim the final permit was "rammed through largely due to political pressure by the legislature and governor's office" despite facing widespread public opposition.

A representative for the Kansas Department of Health and Environment could not immediately be reached for comment.

In addition to questions about the permit's legality, the environmental groups argue that the coal-fired plant would primarily serve residents and businesses in Colorado, while emitting "massive amounts of air pollutants ... on downwind Kansans"

The Kansas Department of Health and Environment, in a July 20 order, granted Sunflower's request to "stop the construction clock" on its air permit for the expansion project, essentially waiving a

deadline for construction to begin on the project until the Supreme Court weighs in on the Sierra Club's legal challenge.

COMPANY REFERENCED IN THIS ARTICLE:

Sunflower Electric Power Corp.

Industry Document: Groups Ask KS Supreme Court to Overturn Sunflower Coal Plant Permit

E-mail this story.

Electric trade groups call EPA cooling water intake rule too costly

by Kathleen Hart

The Edison Electric Institute voiced support for elements of the U.S. Environmental Protection Agency's proposed new rule on cooling water intake structures at existing power plants but urged the agency to modify parts that it considers unnecessary, infeasible and too costly.

"We urge EPA to address the technical issues raised in industry's comments in order to contain costs to electricity consumers and avoid potential reliability impacts in some areas," EEI President Tom Kuhn said in an Aug. 17 news release.

Kuhn said EEI is committed to reducing "potential harmful effects of impingement and entrainment and to protect the environment as an integral component of generating electricity for the nation. But we also believe strongly that EPA can and should produce a final rule that is reasonable, streamlined and imposes only requirements whose costs are commensurate with expected benefits."

EEI filed comments Aug. 17 in response to a sweeping EPA proposal to establish national requirements applicable to the location, design, construction and capacity of cooling water intake structures at existing power plants. The proposal is intended to minimize adverse environmental impacts that may be occurring.

Impingement occurs when fish or shellfish get caught against a screening device when water is drawn through the intake screen. Entrainment happens when smaller fish, eggs and other life-forms are sucked through the screens and into a cooling water system.

In comments filed Aug. 18, the Nuclear Energy Institute said that while the proposed EPA rule has some sensible features, other aspects have "serious flaws" and would be costly to implement.

NEI noted that hundreds of natural gas- and coal-fired power plants and 62 of the nation's 104 commercial nuclear reactors are affected by the proposed cooling water rule, which EPA is expected to finalize in July 2012.

"Numerous scientific studies demonstrate that in many cases cooling water intake structures have had no adverse impact on the overall health of the fish populations near nuclear power plants. These include independent studies that have been reviewed and accepted by state environmental permitting agencies," NEI said in an Aug. 18 news release.

"Without changes, the agency's proposed requirements could force costly, multi-year plant modifications at many of America's power plants, and may even lead to premature closure of some facilities," NEI said in the news release. "Moreover, these measures will not necessarily achieve the overall environmental gains that EPA seeks in this phase of its implementation of Section 316(b) of the Clean Water Act."

NEI noted that the EPA issued the proposed rule last March and has received tens of thousands of comments from members of Congress, governors, state lawmakers, state utility commissions, labor unions, water authorities and others "who share the nuclear energy industry's concerns about the potential economic impact on consumers from higher electricity prices and other unintended consequences that would result from the proposed regulation."

EEI said one of its main concerns is that the EPA's proposal to develop two independent standards, one for impingement and another for entrainment, for which compliance is required during different time frames, "would create uncertainty and wasted investment. EPA should allow state environmental agencies to evaluate impingement and entrainment requirements jointly, incorporating site-specific factors and cost-benefit analysis when deciding whether additional technology is needed at an existing facility."

EEI endorsed the agency's decision not to require utilities in every case to install "closed-cycle cooling" facilities at power plants. It also supported the EPA's decision to direct state environmental agencies to safeguard fish from entrainment after consideration of each site's unique characteristics, weighing costs and benefits and taking into account information provided by plant owners.

In addition, EEI welcomed the agency's proposal to treat rebuilt, repowered and replacement units at existing power plants as "existing facilities," which allows companies to make environmental and energy efficiency upgrades at their facilities "without being subject to requirements that are not feasible or cost effective," the news release added.

However, EEI noted that the proposal would impose a uniform, nationwide mandate to meet "rigid" impingement standards. "These standards are based on the false assumption that they are achievable at all existing facilities," the news release said. "[T]here is no valid environmental or biological justification for precluding the use of the same site-specific flexibility for impingement that the proposed rule provides for entrainment."

EEI encouraged the EPA to modify the proposal to provide permit writers the same flexibility to determine the need for additional impingement measures the proposal provides for entrainment measures.

COMPANIES REFERENCED IN THIS ARTICLE:

Edison Electric Institute

Nuclear Energy Institute

Industry Document: Nuclear Energy Industry Files Comments on EPA's Proposed Rule on Cooling Water Systems

Industry Document: EEI Supports Elements of EPA Cooling Water Intake Structures Proposal, Urges Agency to Revise Others

E-mail this story.

Fla. PSC weighs nuclear expansion plans of NextEra, Progress subsidiaries

by Wayne Barber

The Florida Public Service Commission continued hearing testimony Aug. 17 into rate recovery for potential new nuclear generation capacity planned by utility subsidiaries of NextEra Energy Inc. and Progress Energy Inc. No decision is expected until October, a PSC spokeswoman said.

NextEra's Florida Power & Light Co. is undertaking projects that qualify for cost recovery under the state's Nuclear Cost Recovery Clause process. The company is pursuing an extended power uprate project at its St. Lucie and Turkey Point plants. It is also seeking the development of two new nuclear units, Turkey Point 6 and 7.

In addition to questioning the adequacy of cost controls for the FPL projects, the state Office of Public Counsel questioned if Progress Energy can complete its planned Levy County Nuclear project by 2022 or so.

The office wants the commission to withhold any recovery for the Levy County project that is not directly linked to securing a combined construction and operating license, or COL, from the U.S. Nuclear Regulatory Commission. "By doing this, the commission will limit the ratepayers' losses in paying for PEF [Progress Energy Florida] to achieve nothing but a COL for a staggering $1 billion cost even if PEF cancels the [Levy County Nuclear] project after receipt of the COL," the office argued.

Progress Energy hopes to receive its combined license from the NRC in 2012 or early 2013, company spokesman Tim Leljedal said Aug. 17. "We will continue to reassess the project on a regular basis," the spokesman said.

Progress Energy has already scaled back the rate recovery levels for both the Levy project as well as a multiphase power upgrade at the troubled Crystal River plant that remains offline while it undergoes repairs. Florida ratepayers who paid $5.53 per 1,000 kWh toward the projects in 2010 would pay $4.65 per 1,000 kWh in 2011, Leljedal said.

Meanwhile, Progress Energy is also seeking a phased-in, extended power uprate at its Crystal River nuclear plant. The uprate plans have been complicated, however, by Progress Energy's ongoing concrete problems at Crystal River, which are expected to keep the nuclear plant offline until 2014.

Progress Energy is expected to complete its merger with Duke Energy Corp., another major Southeast nuclear operator, by the end of the year.

The Florida Industrial Power Users Group, White Springs Agricultural Chemicals Inc. d/b/a PCS Phosphate White Springs, Southern Alliance for Clean Energy, and the Federal Executive Agencies have each been granted intervention in the Florida PSC proceedings.

"No intervenor has demonstrated that a single dollar was imprudently incurred" on the FPL project, the PSC said in the order.

FPL is seeking more than $196 million. For a typical residential customer consuming 1,000 kWh per month, this amount equates to an approximate monthly bill impact of $2.09, the PSC noted.

But the Office of Public Counsel argued that FPL has failed to use some traditional cost controls and wants the commission to order the utility to do a "breakeven calculation that includes all capital costs."

The proposed nuclear expansions have been touted as a way to reduce Florida reliance on fossil fuel generation and in the process avoid significant carbon dioxide emissions.

COMPANIES REFERENCED IN THIS ARTICLE:

Duke Energy Corp.	DUK
Florida Power & Light Co.	
NextEra Energy Inc.	NEE
Progress Energy Inc.	PGN

Misc: Florida Power & Light Co.

E-mail this story.

FERC approves Riverstone affiliate's purchase of 7 New England, mid-Atlantic power plants

by Marcy Crane

Finding that the transaction is consistent with the public interest, FERC on Aug. 16 approved Sapphire Power Acquisition LLC's plan to buy a portfolio of seven gas-fired, combined-cycle power plants in New Jersey, Pennsylvania and Massachusetts from Morris Energy Group LLC subsidiary MEG Holdings.

Under the deal, Sapphire, a portfolio company largely controlled by Riverstone/Carlyle Renewable and Alternative Energy Fund II, will acquire MEG Holdings' 100% indirect common equity ownership interest in the 172.8-MW Bayonne plant in Bayonne, N.J.; the 172.9-MW Camden facility in Camden, N.J.; the 74.1-MW Dartmouth Power Associates facility in Dartmouth, Mass.; the 65-MW Elmwood Park Plant in Elmwood Park, N.J.; the 140-MW Newark Bay facility in Newark, N.J.; the 140.2-MW Pedricktown plant in Pedricktown, N.J.; and the 52.3-MW York facility in York, Pa.

The Dartmouth plant sells its output into the ISO New England Inc. wholesale market, while the other six sell their output into the PJM Interconnection LLC market.

Riverstone/Carlyle Renewable and Alternative Energy Fund II is an investment fund managed by Riverstone Holdings LLC. Riverstone holds direct and indirect interests in a number of generating facilities in locations including California, New York, Texas, the Carolinas and Manitoba.

When the parties in July asked FERC to approve the transaction, the financial terms of the deal were not disclosed.

The parties did, however, explain that Riverstone and its affiliates have no holdings in the PJM region and three units with a combined capacity of less than 150 MW in the ISO New England region. They also noted that affiliates control a natural gas-gathering system in Pennsylvania and two intrastate natural gas storage facilities — one in California and one in Oklahoma — although they insisted that none of those holdings create any market power concerns.

In approving the uncontested deal, FERC found that it will have no adverse effects on competition, rates or regulation, and that it raises no cross-subsidization concerns. The commission apparently was satisfied by the applicants' assurances that post-transaction, Sapphire and its affiliates still will own or control less than 0.5% of the total installed capacity in the ISO New England market of approximately 32,000 MW.

The applicants have said that they expect the deal to close on or about Sept. 1. (EC11-96)

COMPANIES REFERENCED IN THIS ARTICLE:

Morris Energy Group LLC

PJM Interconnection LLC

Riverstone Holdings LLC

Riverstone/Carlyle RAE Fund II

Sapphire Power Acquisition LLC

Merger App: Bayonne Plant Holding, LL

E-mail this story.

Inhofe: EPA exaggerated FERC collaboration on reliability impact of utility MACT rule

by Kathleen Hart

U.S. Sen. James Inhofe, R-Okla., ranking Republican on the Senate Environment and Public Works Committee, raised concerns that the U.S. Environmental Protection Agency exaggerated the extent of its collaboration with FERC to assess how EPA's utility maximum achievable control technology, or utility MACT, rule could affect electric reliability.

In an Aug. 16 letter to EPA Administrator Lisa Jackson, Inhofe said it "appears that the Environmental Protection Agency (EPA) has grossly exaggerated the amount of coordination that has occurred" with FERC concerning the utility MACT rule, also known as the utility air toxics rule, and its implications for electric reliability.

"It is critical that EPA clearly display the specific level of outreach and consultation that is stated in the Utility Air Toxics Rule preamble so that we can better understand the extent to which reliability concerns were evaluated," Inhofe wrote in the letter to Jackson. "Given the scope of this proposal, and the nearly $11 billion annual costs that EPA estimates from this one rule, American citizens quite literally cannot afford to have you get this wrong."

Inhofe noted in an Aug. 17 news release that the EPA reported this year that the agency and FERC were jointly modeling the potential for coal-fired power plant closures prompted by the utility MACT rule, "but as FERC's response to a May 17 letter from Senator Lisa Murkowski (R-AK), Ranking Member of the Senate Energy Committee, revealed, nothing as extensive as joint modeling has occurred."

The EPA closed the comment period Aug. 5 on the utility MACT rule, which one industry observer has called "the biggest, most expensive and probably most difficult-to-understand EPA regulatory issue." The agency is expected to issue the final rule in November.

Several major electric power generators filed comments in the first week of August with the EPA on the utility MACT rule, with reactions ranging from strong support to harsh criticism. Southern Co. said the rule is "irredeemably flawed" and urged the EPA to "start anew" with different data and assumptions. On the other hand, a group of utilities and generators, including Constellation Energy Group Inc., Sempra Energy and Public Service Enterprise Group Inc., said the rule provides "the business certainty the electric sector needs to move forward with capital investment and decisions." The group, the Clean Energy Group, said it supports the EPA finalizing the rule by November. It also said the three-year schedule is sufficient without creating "significant impacts" on system reliability.

But Inhofe argued that there is "bipartisan concern" in Congress that the EPA's utility MACT rule "will result in a significant number of plant closures, increase electricity rates for every American, and, along with the transport rule, destroy nearly 1.4 million jobs."

"Now we have learned that EPA has failed to collaborate with FERC to consider how Utility MACT will affect electric reliability," Inhofe said. "In fact, FERC Commissioner [Philip] Moeller went as far as to say that 'the Commission has not acted or studied or provided assistance to any agency, including EPA.'"

In an Aug. 1 letter to Murkowski, Moeller added, "I do not believe that the meetings that have been held between staff in the Office of Electric Reliability and EPA constitute an Inter-Agency Task Force as described" in the senator's question to FERC.

Inhofe pressed Jackson to provide detailed information on the extent to which EPA considered electric reliability in several other proposed rules, including the Cross-State Air Pollution Rule finalized in July and the January 2010 proposed reconsideration of the standards for ground-level ozone.

In his seven-page Aug. 16 letter, Inhofe asked for a list of all the public utility commissions that the EPA consulted with on reliability issues, including copies of correspondence and a schedule of all meetings between both parties. He also asked Jackson to provide information on correspondence and meetings dealing with reliability issues between the EPA and RTOs, the North American Electric Reliability Corp., the U.S. Department of Energy and FERC.

"EPA is pursuing its war on affordable energy without regard to the nation's economy or energy needs," Inhofe said in the news release. "EPA should halt this process and finally engage in a comprehensive regulatory analysis of Utility MACT and all its pending train wreck rules."

COMPANIES REFERENCED IN THIS ARTICLE:

Constellation Energy Group Inc.	CEG
Public Service Enterprise Group Inc.	PEG
Sempra Energy	SRE
Southern Co.	SO

Industry Document: Inhofe Questions EPA Over Failure to Consider Electric Reliability for Utility MACT

Industry Document: Letter from James M. Inhofe to Lisa Jackson

Industry Document: Letter to Lisa A. Murkowski from Philip D. Moeller

E-mail this story.

Business Roundtable: EPA ozone standards would damage US economy

by Kathleen Hart

Joining the U.S. Chamber of Commerce, numerous industry groups and many members of Congress, the Business Roundtable warned that the new ground-level ozone standards proposed by the U.S. Environmental Protection Agency would "negate any progress on creating jobs in the private sector."

In a motion filed Aug. 12 with the U.S. Court of Appeals for the District of Columbia Circuit, the EPA said that the Obama administration is reviewing its proposed Clean Air Act health standard for ground-level ozone and plans to issue the rule "shortly." The EPA's draft final rule reconsidering National Ambient Air Quality Standards for ozone is still undergoing interagency review under Executive Order 12866, the agency said in the court filing.

"The administration is obviously making a serious review of these damaging regulations, and we're encouraged by that. President Obama again … pointed to jobs as his administration's priority, and the EPA's proposals would negate any progress on creating jobs in the private sector," Business Roundtable President John Engler said in an Aug. 12 news release. "In reality, the rules would be the equivalent of posting signs on the U.S. economy, 'Closed for business.'"

The EPA's decision to seek "further delay on its proposed ozone rules tells us the Obama administration recognizes the disastrous consequences that more restrictive ozone regulations would have on the economy and jobs creation," Engler said. The court filing "is significant news. While it relates to the EPA's revised air quality standards issued in 2008, the EPA's motion announcing its inability to act

yet also casts doubt on the merits of the agency's 2011 proposed standards."

EPA Administrator Lisa Jackson is "fully committed to finalizing EPA's reconsideration of the Clean Air Act health standard for ground level ozone, which is currently going through interagency review led by the White House Office of Management and Budget," an EPA spokesman said Aug. 12. "Following completion of this step, EPA will finalize its reconsideration. We look forward to doing so shortly."

The EPA's court filing came as the proposed new ozone rule faces increased scrutiny. Citing a "fragile" economy, the U.S. Chamber of Commerce and more than 170 other business groups wrote a letter to President Barack Obama on Aug. 11, urging him to stop the EPA from moving ahead with new standards for ground-level ozone, which is the main component of smog. In July, Sens. Jeff Sessions, R-Ala., Mary Landrieu, D-La., and 32 other members of the Senate wrote to Jackson urging the agency not to finalize its proposed new standards.

As pressure mounts on the administration to delay issuing new ozone standards, the EPA also has been asked to reconsider aspects of another rule, namely the agency's final Cross-State Air Pollution Rule. The EPA issued the final version of the Cross-State Air Pollution Rule on July 7, roughly one year after the agency published its proposed transport rule. Citing reliability concerns in Texas, Luminant Generation Co. LLC on Aug. 5 filed a request with EPA to reconsider aspects of the rule and stay the rule's effective date of Jan. 1, 2012.

COMPANY REFERENCED IN THIS ARTICLE:

Luminant Generation Co. LLC

Industry Document: Environmental Protection Agency's Move on Ozone Recognizes Threat to Jobs, Economy

E-mail this story.

FERC approves Duke Energy Vermillion's sale of stake in Ind. gas plant

by Marcy Crane

Noting that the deal was uncontested, FERC on Aug. 12 approved Duke Energy Vermillion LLC's proposed sale of its stake in the Vermillion generating facility and associated interconnection facilities in Indiana to Duke Energy Indiana Inc. and Wabash Valley Power Association Inc.

In doing so, the commission found that the transaction will have no adverse effects on competition, rates or regulation, and that it raises no cross-subsidization concerns.

The parties in June asked FERC to sign off on their proposed transaction. According to their filing, Duke Energy Indiana and Wabash Valley would acquire Duke Energy Vermillion's 75%, undivided ownership interest in the 720-MW, gas-fired merchant peaking facility in Vermillion County, Ind., for $81.6 million. Duke Energy Indiana will pay about $68 million of the purchase price, and Wabash Valley will pay the $13.6 million balance.

Upon closing of the transaction, expected in the first quarter of 2012, Duke Energy Indiana will own a 62.5% undivided interest in the plant as a tenant in common with Wabash Valley, which already owns a 25% stake in the facility and will expand its ownership interest to 37.5% upon consummation of the deal.

Approving the sale, FERC noted that the applicants must comply with a hold harmless commitment requiring them to secure commission approval through a Federal Power Act Section 205 rate proceeding should they seek to recover transaction-related costs through their wholesale power or transmission rates. Before doing so, applicants would be required to specifically identify which costs they seek to recover and demonstrate that those costs are exceeded by the savings produced by the transaction.

"Such a hold harmless commitment will protect customers' wholesale power and transmission rates from being adversely affected by the proposed transaction," the commission said.

FERC further noted that compliance with reliability and cybersecurity standards "is mandatory and enforceable regardless of the physical location of the affiliates or investors, information database, and operating systems," and that applicants must report "any change in status that would reflect a departure from the characteristics the commission relied upon in granting market-based rate authority."

Duke Energy Vermillion and Duke Energy Indiana are subsidiaries of Duke Energy Corp. (EC11-90)

COMPANIES REFERENCED IN THIS ARTICLE:

Duke Energy Corp. **DUK**

Duke Energy Indiana Inc.

Duke Energy Vermillion LLC

Wabash Valley Power Association Inc.

Merger App: Duke Energy Indiana Inc.

E-mail this story.

FERC/NERC report outlines steps to avoid winter outages in Southwest

by JP Finlay

Six months after a severe cold spell caused rolling blackouts and natural gas curtailments in the Southwest, FERC and the North American Electric Reliability Corp., as part of a joint investigative task force, concluded that power generators were generally reactive in their approach to winterization and preparedness and failed to take proactive steps that could have prevented the outages.

FERC and NERC issued a report Aug. 16 that included a series of recommendations designed to avoid similar blackouts and gas curtailments should extreme cold temperatures hit the region again.

"Generators and natural gas producers suffered severe losses of capacity despite having received accurate forecasts of the storm," the report said. "Entities in both categories report having winterization procedures in place. However, the poor performance of many of these generating units and wells suggests that these procedures were either inadequate or were not adequately followed."

FERC Office of Enforcement Director Norman Bay addressed reporters during an Aug. 16 news briefing to discuss the more than 200-page report. The severe weather, which wreaked havoc on power and gas systems in early February, affected 4.4 million electric customers and 50,000 gas customers. The affected area stretched from Texas to Arizona. At the peak of the severe weather, about one-third of the available generation in the Electric Reliability Council of Texas Inc. territory was unavailable.

"We believe many of the outages suffered by residents in Texas, Arizona and New Mexico could have been prevented," Bay said.

The best means for prevention, according to the report, would come from increased winterization. "The task force has identified several pro-

active steps that can be taken by state regulators, electric generators and natural gas suppliers in the Southwest to improve the reliability of energy supply for customers during extreme cold weather," FERC Chairman Jon Wellinghoff said in a news release. "We urge them to carefully consider those recommendations and to work together to implement them before another cold weather event hits the region."

The report recommended that states in the region consider mandatory winterization programs. NERC plans to work on addressing winterization within its reliability standards.

"The task force attributed most of the natural gas shortages and outages to prolonged freezing weather that resulted in dramatically reduced supply and unprecedented high demand," the news release said. "Most electric outages were caused by weather-related mechanical problems such as frozen sensing lines, equipment, water lines and valves."

Tom Galloway, chief reliability officer and senior vice president for NERC, said that though the extreme weather presented a significant challenge, a similar winter storm in 1989 could provide context to the outages. "The weather was unusually severe but not without precedent. Several generators that failed in 1989 failed again in 2011," he said.

"This joint report demonstrates the high priority both NERC and FERC place on reliability," NERC President and CEO Gerry Cauley said in the release.

Both FERC staff and Galloway pointed out during the briefing that the purpose of the report was not to assign blame but to look at the causes of the outages and figure out the best ways to prevent them in the future. In addition to winterization, the report said generation owners and operators should ensure freeze protection of equipment, obtain data on temperature limits for equipment, and review distribution of reserves to ensure deliverability during contingencies. The report also recommended that states work together to adopt minimum standards for weather-related production shortages.

"We're not looking to point fingers," a FERC staffer said. "We were interested in making recommendations" to prevent future outages.

Galloway said the first goal is to "make sure we thoroughly communicate findings of the report and consider follow-up visits. … There are a range of actions we can take." He would not speak to any specific violations or potential violators.

FERC staff said that because of the intense heat the Southwest encounters in summer months, the design of generation facilities is more susceptible to severe winter weather.

Electric Transmission Texas LLC submitted plans to build new transmission lines in an effort to increase capacity in the Rio Grande Valley region of Texas. In a previous interview with SNL Energy, Electric Transmission Texas President Calvin Crowder said his company moved as fast as possible to apply for new lines in the area after the severe February weather left many of the region's customers without power. According to the report, on Feb. 3 alone 180,000 customers in the Rio Grande Valley lost power, with temperatures remaining below freezing for hours.

COMPANIES REFERENCED IN THIS ARTICLE:

Electric Reliability Council of Texas Inc

Electric Transmission Texas LLC

Industry Document: Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011

Industry Document: FERC and NERC Release Task Force Report on Southwest Outages

E-mail this story.

Groups sue EPA over biomass rule, citing CO2 emissions from burning wood

by Kathleen Hart

Several conservation groups filed a lawsuit with the U.S. Court of Appeals for the District of Columbia Circuit challenging a U.S. Environmental Protection Agency rule that exempts large-scale biomass facilities from carbon dioxide limits under the Clean Air Act for the next three years.

In an Aug. 12 petition for review, the Center for Biological Diversity, Conservation Law Foundation, Natural Resources Council of Maine, Georgia ForestWatch and Wild Virginia asked the court to overturn the CO2 exemption for wood-fired power plants and other biomass incinerators.

"EPA's unlawful rule will cause immediate harm as it will encourage a rush to build biomass power plants and other facilities without accounting for or controlling carbon pollution that contributes to global warming," the conservation groups said in an Aug. 15 news release.

The EPA signed a final rule July 1 deferring by up to three years the consideration of CO2 emissions when permitting stationary sources of emissions that burn biomass. In the rule, the EPA said the deferral is intended to allow the agency time to complete its work to determine what, if any, treatment biomass-burning sources of emissions should be in the Prevention of Significant Deterioration and Title V programs.

"This is not EPA's final determination on the treatment of biogenic CO2 emissions in those programs," the rule said. "The agency plans to complete its science and technical review and any follow-on rulemakings within the three-year deferral period and further believes that three years is ample time to complete these tasks."

The conservation groups said the EPA's ruling is particularly important for the Southeast, where utilities and independent power producers "are moving briskly forward with dozens of large wood-fired power plants and re-purposed power plants. Local demand from existing and proposed plants for wood fuel could easily outstrip the supply of available wood waste, meaning the facilities would need standing trees to meet the demand."

The Biomass Power Association and the National Alliance of Forest Owners strongly support the EPA's decision to defer biomass from its greenhouse gas "tailoring rule" for three years while the agency further studies the carbon cycle of biomass.

"The EPA has recognized that fossil fuels and biomass emissions should be regulated differently and they need to take a step back and review the science because public policy should reflect scientific fact," National Alliance of Forest Owners spokesman Dan Whiting said Aug. 16. "We don't think the scientific review should be thwarted by the litigation. We'll act to support EPA where we can in the lawsuit."

Whiting said the National Alliance of Forest Owners "will most likely intervene."

Biomass traditionally has been considered a renewable form of energy and is included in most state renewable portfolio standards along with solar, wind and geothermal power. The impetus for many renewable energy programs was to address the threat of global warming by reducing emissions of CO2 and other greenhouse gases.

However, wood contains less energy than coal, "so you have to burn more of it to get the same amount of energy out, and that leads to greater CO2 emissions per unit of energy produced," Kevin Bundy,

senior attorney for the Center for Biological Diversity, said in an Aug. 16 interview.

"Biomass has had this reputation as a clean and green and renewable fuel, but I think that a lot of recent scientific information shows that it doesn't deserve that reputation. The widespread development of bioenergy will increase CO2 concentrations in the atmosphere and also put a lot of pressure on forests to produce the volumes of wood that are necessary to produce a lot of electricity," Bundy said.

"I think that there's a strong likelihood that it would be harmful if we turn to it on a really wide scale, and the concern is that policies like EPA's policy of just looking the other way and refusing to regulate for a few years will encourage exactly that kind of rush to development," he said. "If we build these plants, they're going to be there for a long time, and they're going to generate a long-term demand for fuel. And they're going to be pumping CO2 into the atmosphere for a very long time as well."

Whiting countered that it is unlikely that "there's going to be this mad rush to permit and build biomass facilities before the three-year review is done."

Whiting said he hopes there will be some biomass plants built in the next few years, "but I don't expect to see a big rush."

Dylan Voorhees of the Natural Resources Council of Maine said biomass energy should continue to be an important part of Maine's energy mix. "However, it is essential that we use tools like the Clean Air Act to ensure that we use biomass efficiently to minimize pollution and ensure that our forests are managed sustainably," he said. "If we don't, our air, water and forests will suffer."

Industry Document: Petition for Review

Industry Document: Lawsuit Challenges Clean Air Act Exemption for Biomass Burners

E-mail this story.

Zachry to build Warren County, Va., gas plant for Dominion

by Wayne Barber

Dominion Resources Inc. has selected a subsidiary of San Antonio-based Zachry Holdings to build its 1,300-MW Warren County combined-cycle gas power plant near Front Royal, Va.

During its last quarterly earnings call, Dominion executives said they had signed an engineering, procurement and construction, or EPC, contract for the $1.1 billion plant in Virginia's Shenandoah Valley. Then Zachry said in an Aug. 1 news release that it has been selected for "turnkey" EPC services.

The Warren County project hopes to receive a full notice to proceed in May 2012, with a completion in 2014, Zachry said. Mitsubishi will provide much of the major technology for the power plant, Zachry said. No financial terms were disclosed.

The Warren County project, less than 70 miles from Washington, D.C., is part of a major generation building spree that Dominion and its Virginia Electric and Power Co. utility subsidiary are conducting in Virginia between now and 2015.

Projects including Warren County, the recently completed Bear Garden gas plant in Buckingham County and the nearly complete Virginia City Hybrid coal-and-biomass plant in Wise County should add more than 2,400 MW of capacity to Dominion's Virginia fleet.

The Warren County plant still needs final approval, including rate recovery authority, from Virginia's State Corporation Commission, said Dominion spokesman Dan Genest. A hearing is set for December. Dominion has said previously that if approved, the monthly bill of a residential customer who uses 1,000 kWh each month would increase by 75 cents beginning April 1, 2012, to pay for the financing costs of the power station's construction for a 12-month period.

Dominion's generation plans are fleshed out further in a recent investor presentation.

The company also noted in its last quarterly earnings call that VEPCO expects to file its integrated resource plan with the Corporation Commission by Sept. 1.

Dominion caught a break when the U.S. EPA's new Cross-State Air Pollution Rule excluded both Massachusetts, where its Brayton Point 1-3 complex is located, along with Rhode Island, where its Manchester Street plant is located, Dominion Chairman, President and CEO Thomas Farrell said in the earnings conference call.

"We are evaluating our compliance options for our generating fleet in Virginia including installing control equipment, replacing some of our existing generation with new gas-fired facilities, adding additional transmission capacity or some combination of all three," Farrell said. Expect such issues to be addressed in the Virginia IRP, Farrell said.

Also during the earnings call, Farrell declined to give any update on the company's effort to sell its Kewaunee nuclear plant in Wisconsin.

COMPANIES REFERENCED IN THIS ARTICLE:

Dominion Resources Inc. D

Virginia Electric and Power Co.

Transcript: Dominion Resources Inc. (D)

Presentation: Dominion Resources Inc. (D)

PR: Zachry selected to build Dominion's Warren County Project

E-mail this story.

Dominion power plant construction program to bring about $3.3B in benefits to Virginia

by Wijdan Khaliq

Dominion Resources Inc. subsidiary Virginia Electric and Power Co. d/b/a Dominion Virginia Power's nine recent major power projects completed, under way or planned are expected to produce more than $3.3 billion in economic benefits for Virginia by 2015.

Dominion's power plant investments will support more than 14,200 construction jobs in Virginia from 2007 through 2015. Additionally, once the projects are completed, their ongoing operations will produce annual economic benefits of more than $290 million and generate more than 750 jobs beginning in 2015, according to a study by the Richmond, Va.-based economic research and consulting firm of Chmura Economics & Analytics.

"As the gap between demand and supply widens, the best way to secure Virginia's energy independence is to build more power generating facilities in our commonwealth," Virginia Chamber of Commerce president and CEO Barry DuVal said in a statement issued Aug. 15 by Dominion. "The [2007] re-regulation act is designed to help ensure capital is available to invest in new power production

while also restoring Virginia to regulatory oversight by the State Corporation Commission."

The study measured benefits attributed directly to the construction, including spending for labor, materials, equipment and professional services. It also measured indirect and induced economic benefits from construction, according to the news release.

The nine projects in the study are the 580-MW Bear Garden facility in Buckingham County, Va., which began commercial operation this year; the 585-MW Virginia City Hybrid Energy Center in Wise County, Va., which is scheduled to become operational next year; Warren County, a 1,300-MW station projected to begin commercial operations in late 2014; Halifax Solar, a 4-MW solar development in Halifax County, Va., for which the company expects to apply for state regulatory approval in the spring of 2012; Bremo, a Fluvanna County, Va., station the company will convert from coal to natural gas; coal-burning facilities in Altavista, Hopewell and Southampton counties, Va., each of which will be converted to operate on waste wood generated by the timber industry to produce about 150 MW from biomass; and Chesterfield Power Station, where a scrubber has been installed to reduce emissions from three coal-powered units. One unit has been connected, and the other two will be connected to the system by the end of the year. This scrubber joins one at the station that began operating in 2008.

The new generating facilities will add more than 2,400 MW of capacity to Dominion's roster of power plants, the news release stated.

COMPANIES REFERENCED IN THIS ARTICLE:

Dominion Resources Inc. **D**

Virginia Electric and Power Co.

PR: Dominion Virginia Power's Construction Program Brings Virginia More Than $3 Billion in Economic Benefits

E-mail this story.

Heat pushes ERCOT to temporarily re-activate mothballed units

by Peter Marrin

To help address emergency situations during the extreme heat and drought, and at the request of Public Utility Commission of Texas Chairman Donna Nelson, the Electric Reliability Council of Texas Inc. announced Aug. 16 it has executed short-term contracts with two generation owners to re-activate four "mothballed" units.

The grid operator said in a news release, NRG Energy Inc. and Garland Power and Light will return two natural gas-fired units each for a total of approximately 400 MW, which will be available if needed through October "to reduce the risk of rotating outages across the ERCOT region."

"We don't know if, or how much, these units will be needed, but if needed, the cost will be minor when divided by the 23 million consumers in the region and when compared to the much higher costs and problems from statewide rolling blackouts which these units will help avoid," ERCOT CEO Trip Doggett said.

Nelson addressed the urgency of the situation in an Aug. 12 letter and urged ERCOT to take actions necessary to address the extreme circumstances.

"The record breaking heat and drought have placed increased stress on the generation facilities operating within ERCOT, increasing the likelihood of the unplanned mechanical breakdown of generation units at a time when our electric demand is soaring," Nelson said, directing the grid operator to "look at all available options to ensure the reliability and adequacy of the ERCOT transmission grid at this critical juncture."

According to ERCOT media representative Dottie Roark, the process began in mid-July by asking the owners of the mothballed units how long it would take them to come out of retirement.

"All but two plants said it would take two months or longer, so they would not be available until well after summer," Roark explained. "So these two plants (four units total) are the ones that we worked with to work out an arrangement to return them to service."

Roark identified the units as Garland's Spencer 4 and Spencer 5 in Denton County, Texas, each rated at 61 MW, as well as NRG's SR Bertron Unit 1 and SR Bertron Unit 2 in La Porte, Texas, rated at 118 MW and 174 MW, respectively. The temporary contracts are based on the pricing methodology used for reliability-must-run units under the ERCOT market rules. The payments will be figured on a cost-recovery model, meaning the owners get paid for their fixed costs, including staff, maintenance and even fuel.

To minimize the impact of this temporary reliability tool on other market participants in the competitive market, Doggett said the four units will be called on only when necessary to avoid emergencies so the units will not displace units that are on line and bidding into the market.

"This has been a highly unusual year for ERCOT with record-breaking temperatures — starting as early as May — plus an increasing demand for electricity as the state's economy and population growth fuel greater energy use," Doggett said.

"In addition, we are facing the worst drought in Texas history. Without rainfall in the near future, we anticipate increased generation outage rates because of power plant cooling water issues," he said.

COMPANIES REFERENCED IN THIS ARTICLE:

Electric Reliability Council of Texas Inc

NRG Energy Inc. **NRG**

Company Notice: ERCOT

PR: ERCOT Announces Temporary Contracts to Add Generation during Current Extreme Heat, Drought

E-mail this story.

KBR gets contract for air controls at Scherer plant

by Barry Cassell

Construction contractor KBR Inc. announced Aug. 15 that it has been awarded a contract by Southern Co. for the installation of flue gas desulfurization, or FGD, and selective catalytic reduction systems and related equipment at two units of the coal-fired Scherer plant in Georgia.

The new equipment will be installed on two 880,000-kW units at the plant, KBR said. Scherer, with a total 3,520 MW of coal-fired capacity, is one of the largest single generating stations in the nation, KBR noted in a statement.

Scherer is co-owned by various parties, including Southern's Georgia Power Co. unit and regional generators such as Southern subsidiary Gulf Power Co., JEA and the Municipal Electric Authority of Georgia. The plant co-owners are under a 2007 mandate by the state of Georgia to install FGD and SCR equipment on all four coal units at the plant on a defined schedule.

Georgia Power spokesman Jeff Wilson said in June that Georgia Power is in construction on SO2 scrubbers (also known as FGD), SCR for NOx control and baghouses to limit particulates at units 1, 2 and 4 at Scherer, with those controls finished on unit 3.

KBR will provide installation of all equipment and associated piping, steel, ductwork, electrical, instrumentation and related work, KBR said in the Aug. 15 statement. KBR also will be responsible for other tasks including procurement of piping and valves. The contract award follows the completion of various projects for Southern Co. by KBR, most recently a heavy structural steel construction project at Scherer.

"This project continues a successful relationship with Southern Company and expands KBR's presence in the U.S. domestic power industry," said Danny Hicks, senior vice president of KBR Construction.

Scherer was switched in the 1990s from burning eastern U.S. bituminous coal to subbituminous coal out of the Powder River Basin, sending shock waves through the eastern U.S. coal industry due to the sheer number of tons of coal involved and the long rail haul to get PRB coal to Georgia. Gulf Power has told the Florida Public Service Commission that the plant will likely stay on PRB coal, even with the FGD equipment installed, because it is likely it will remain the least-cost fuel.

The SNL database shows Scherer with 3,416 MW (operating) of coal capacity and having taken delivery of 4.45 million tons of coal in the first four months of this year from several PRB mines, including the Belle Ayr and Eagle Butte mines of Alpha Natural Resources Inc. and the Antelope mine of Cloud Peak Energy Inc.

COMPANIES REFERENCED IN THIS ARTICLE:

Alpha Natural Resources Inc.	ANR
Cloud Peak Energy Inc.	CLD
Georgia Power Co.	
Gulf Power Co.	
JEA	
KBR Inc.	
Municipal Electric Authority of Georgia	
Southern Co.	SO

Industry Document: KBR to Execute Equipment Installation at One of the Nation's Largest Power Generating Stations

E-mail this story.

Maxim Power gets final approval for 500-MW Alberta coal plant

by Susan Nelson

The Alberta Utilities Commission has given final approval to a 500-MW coal-fired plant proposed by Maxim Power Corp. after being satisfied that the C$1.5 billion facility will be in the public interest and that the company would mitigate whatever environmental problems might occur.

The Pembina Institute, a Canadian environmental group, immediately denounced the commission's Aug. 10 decision as not safeguarding the public interest but helping the plant avoid compliance with impending federal regulations on pollution from coal-fired plants.

The AUC gave interim approval to the plant June 30 after the company pleaded that new generation was urgently needed in Alberta, private investors expected regulatory action on its application and a provincial decision was needed to address the potential impact of pending federal action.

Pembina and another environmental group, Ecojustice, have already filed a motion for leave to appeal to the Court of Appeal of Alberta over the interim approval and said they are considering their options. The regulators' decision sets no conditions on the plant's potential greenhouse gas emissions, the groups contend.

Maxim Power plans to bring the plant online before July 1, 2015, when Pembina expects federal pollution regulations to go into effect. The plant was approved by the AUC as meeting or able to meet provincial standards.

The plant is to be built adjacent to Maxim's 150-MW H.R. Milner plant and is known as M2. It will have a pulverized coal combustion system, a supercritical high-pressure steam generator, a high-efficiency steam turbine generator, air emissions control equipment and a water treatment system. The original unit, operating since 1972, is to be decommissioned once its operating license expires in 2017.

The AUC said that through the design of the plant, commitments Maxim Power has made to mitigation measures and oversight by Alberta Environment, it was "satisfied that Maxim has provided credible evidence showing that the air quality, ambient air quality, criteria air contaminants and potentially acidifying air emissions issues have been addressed."

Ambient air quality in the area of the plant site will now occasionally exceed the Alberta Ambient Air Quality Objectives for sulfur dioxide, total particulate matter and respirable or very fine particulate matter, the environmental impact assessment stated, according to the AUC.

When the second plant comes into operation, sulfur dioxide, nitrogen dioxide, total particulate matter and respirable particulates are "predicted to exceed the one-hour exposure duration; SO2 PM2.5 and TPM were predicted to exceed the 240-hour exposure duration; and dust fall was near the 30-day exposure duration," the AUC said.

"The commission is satisfied that the power plant is designed, and can be constructed and operated, to meet all applicable provincial air emission standards," the AUC said.

The two areas of concern to the AUC were the capture and disposal of ash as well as fogging and icing in the vicinity of the power plant, particularly on Highway 40, which runs adjacent to the power plant.

Within one year of operation, the existing disposal facility for the ash could be at capacity and, therefore, Maxim Power must prepare a new Alberta Environment-approved ash disposal facility as a condition of approval for the new power plant.

Another condition calls for Maxim Power to monitor and if necessary mitigate the effects of fogging and icing on Highway 40 to the satisfaction of Alberta Transportation, the AUC said.

Maxim Power on Feb. 3, 2009, applied to the AUC to construct and operate the plant. The Pembina Institute had asked for a hearing on the application on behalf of two people living in the area, but the

commission said the individuals, when contacted, had no interest in a hearing. No public hearing was held on the application.

According to Maxim Power, the new plant will add C$3.2 million per year to the local economy when in operation, employing 30 full-time positions. (Decision 2011-337)

COMPANY REFERENCED IN THIS ARTICLE:

Maxim Power Corp. **MXG**

Regulatory Filing: Maxim Power Corp (MXG)

Industry Document: Alberta Utilities Commission Fails to Protect Public Interest with Final Coal Plant Approval

E-mail this story.

FERC issues final impact statement for proposed removal of PG&E hydro project

by Wijdan Khaliq

FERC on Aug. 16 issued a final environmental impact statement for the proposed surrender of license of Pacific Gas and Electric Co.'s Kilarc-Cow Creek Project.

The project consists of two developments with a combined capacity of 4.67 MW and is on Old Cow Creek, South Cow Creek and tributaries in Shasta County, Calif. The two hydro facilities are each more than a century old.

The report by FERC listed three alternatives other than the company's proposal, which is to decommission the generating facilities and remove most of the components. Action alternative one was to surrender the Cow Creek development, as proposed by PG&E, and retain sufficient infrastructure at the Kilarc development to maintain the Kilarc forebay for recreation. Action alternative two proposed to surrender the Kilarc development, as proposed by PG&E, and retain sufficient infrastructure at the Cow Creek development to maintain flow in Hooten Gulch so that the Abbot Ditch users can continue to access their water right at the current point of diversion. As a last option, FERC recommended continued project operation with no changes.

If continuing operations is not an option, the project would be decommissioned as proposed by PG&E with the inclusion of all of its proposed mitigation measures.

Determining that the cost of installing required new fish passage facilities would outweigh the economic benefit of generation at the project over the life of a new license, PG&E Corp. subsidiary PG&E in March 2005 reached an agreement with interested parties to surrender the project's license once the current license expired. It agreed to continue to operate the project thereafter on an annual license basis until the project was either acquired by another party or decommissioned.

Unable to find another party interested in taking over the project, PG&E in March 2009 filed an application at FERC to surrender the project's license and decommission the facility over a three-year period. (P-606)

COMPANIES REFERENCED IN THIS ARTICLE:

Pacific Gas and Electric Co.

PG&E Corp. **PCG**

Regulatory Filing: Pacific Gas and Electric Co.

E-mail this story.

NY PSC approves sale of 50-MW coal unit at Fort Drum for biomass conversion

by Wayne Barber

The New York Public Service Commission has approved transferring the ownership a 50-MW coal plant at the Fort Drum Army post to an affiliate of ReEnergy Holdings LLC, which plans to convert the facility to burning chiefly biomass.

The sale of the plant from Black River L.P. has been approved, although no written order has been executed yet by the PSC, a commission spokesman said. SNL Energy records indicate that Black River is an affiliate of Energy Investors Funds Group.

The buyer, ReEnergy Holdings, an affiliate of Riverstone/Carlyle RAE Fund II, could not be immediately reached for comment.

In July 2010, the PSC approved transfer of the plant from the current owner to Catalyst Renewables, but the transaction was never consummated, according to a petition filed with the PSC by ReEnergy and Black River.

Catalyst, however, held an option to acquire an interest in the Black River business, which it will now transfer to the new buyer, ReEnergy, according to the April 22 document.

Once the deal becomes final, ReEnergy plans to convert the facility from coal to primarily wood biomass along with other solid fuels, including "tire-derived" fuel. The new buyer also seeks a "lightened regulatory regime" until it starts using the renewable fuels and becomes a "non-jurisdictional alternate energy production facility" under state policy, according to the petition.

ReEnergy is a limited liability company organized under Delaware law to buy, own and run facilities that convert biomass and waste fuels to produce electric power.

While ReEnergy has recently reported deals to acquire more biomass capacity in New York and the Northeast, its share of the New York generation market will remain minimal and have no impact on regional market power, according to the April filing. Of the roughly 39,000 MW of generation in the New York market, ReEnergy will hold less than 1%.

The power plant is on about 12 acres of land leased from the U.S. Army at Fort Drum, which is in Jefferson County, N.Y. The facility started operation in 1988 as a qualifying cogeneration facility. It also had a long-term contract to sell power to Niagara Mohawk Power Corp., which is now part of the National Grid Group Plc. But that contract was terminated in 1998 and the facility became an exempt wholesale generator, selling its output to the wholesale market.

COMPANIES REFERENCED IN THIS ARTICLE:

Black River L.P.

Catalyst Renewables

Energy Investors Funds Group

National Grid Group Plc

Niagara Mohawk Power Corp.

ReEnergy Holdings LLC

Riverstone/Carlyle RAE Fund II

Regulatory Filing: U.S. Power Fund LP

Company Notice: U.S. Power Fund LP

E-mail this story.

Vogtle spending approved *continued*

budget of $6.1 billion. To deal with this risk, PSC staff proposed that the commission retain the right to disallow the approval of construction spending even after such spending has been approved through the semiannual report process. Georgia Power opposed this position, arguing that the semiannual reviews cannot be challenged once spending has been approved as prudent.

Earlier this month, the commission approved a deal in which Georgia Power agreed to the staff's position in return for the staff dropping a proposed risk-sharing mechanism for the Vogtle project.

"The project is on track and the targets are achievable," Ihrig said. Georgia Power has targeted Vogtle unit 3 for commercial operation in 2016 and Vogtle unit 4 in 2017. Oglethorpe Power Corp., the Municipal Electric Authority of Georgia and the city of Dalton, Ga., also own stakes in the plant.

COMPANIES REFERENCED IN THIS ARTICLE:

Dalton City of

Georgia Power Co.

Municipal Electric Authority of Georgia

Oglethorpe Power Corp.

Southern Co. **SO**

✉ E-mail this story.

Bellefonte to be completed *continued*

and operating licenses. TVA already holds a dormant construction license for the site. It evidently would still need to obtain an NRC operating license.

In early 2010, NRC approved TVA's request to change the unfinished Bellefonte units 1 and 2 to "deferred" status. The commission ruled it has the authority to reinstate construction permits for reactors that the holder of the permits voluntarily surrendered. The reinstatement decision came in a split opinion in which NRC Chairman Gregory Jaczko dissented.

Construction of two partly built reactors at the site was suspended in the late 1980s. TVA terminated the construction permits for the units just a few years ago.

During the board meeting, TVA board member Marilyn Brown vowed that no safety shortcuts would be taken. She said that when Bellefonte 1 was first suspended it was considered more than 80% complete. But so much of the existing facility will be replaced or updated that it is now considered only 50% complete, she said.

Finishing Bellefonte was recommended through TVA's integrated resource plan. While the capital cost of completing Bellefonte plant is high, it is offset by low operational and fuel costs, said Kimberly Greene, TVA's group president for strategy and external affairs.

The Southern Alliance for Clean Energy and other groups have opposed completion of the nuclear plant on cost and safety concerns. A recent SACE report questioned, among other things, the wisdom of reviving a nuclear plant with a foundation that is already decades old and expecting it to run for 40 or more years.

A stream of residents and representatives from various business, government and public interest groups spoke for about three hours, both supporting and opposing the project. Both the public comment session and the regular TVA business meeting lasted from 8:30 a.m. ET to after 4 p.m. ET.

Sequoyah, coal, gas issues addressed

TVA also plans to relicense its Sequoyah nuclear plant near Chattanooga, Tenn. The licenses for the two Sequoyah units are scheduled to expire in 2020 and 2021. TVA would seek to license the plants for an additional 20 years.

TVA's renewed embrace of nuclear power is connected to its planned retirement of large amounts of coal-fired generation to comply with various U.S. EPA mandates. During the meeting, TVA acted to endorse new environmental controls at both the Thomas H. Allen and Gallatin coal plants.

A series of nuclear plant refueling outages, along with tornadoes in April, contributed to the federal utility's $240 million net loss during its fiscal third period. Outages at three of TVA's six reactors contributed to lower net income for the three-month period that ended June 30.

At the meeting, TVA CEO Tom Kilgore said construction of cooling towers is going well at the Browns Ferry nuclear plant in Alabama.

The TVA board also is expected to give final approval to purchasing the Magnolia natural gas-fired, combined-cycle plant in Mississippi. Greene said the plant already has access to a major TVA transmission line.

COMPANY REFERENCED IN THIS ARTICLE:

Tennessee Valley Authority

PR: Weather, Nuclear Refueling, Storm Impact TVA's 3rd Quarter

✉ E-mail this story.

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This Week's Generator Profile

ALLETE Inc. - projects

Plant	State	Fuel	Technology	Plant Owner	Expected Completion	Capacity (MW)	Plant Last Verified Date	Development Status Month/Year	Status
Bison Wind Project	ND	Wind	Wind Turbine	ALLETE (Minnesota Power)	2012	570	Jun-2011	Jun-2011	Construction Begun

Virginia Carolinas - region developments

Altavista	VA	Coal	Steam Turbine: Boiler	Virginia Electric and Power Co	Dec-2013	NA	Jul-2011	Apr-2011	Advanced Development
Cape Charles Offshore Wind Project	VA	Wind	Wind Turbine	Gamesa Technology Corp. Inc.	Dec-2012	5	Apr-2011	Apr-2011	Advanced Development
Columbia Biogas Project	SC	Biomass	Internal Combustion	W2E-Organic Power LLC	2012	2	May-2011	May-2011	Advanced Development
Covington Facility	VA	Biomass	Steam Turbine: Boiler	MeadWestvaco Corp.	NA	75	Jul-2011	Jun-2011	Announced
Crosspointe Power Plant	VA	Gas	Combustion Turbine	Gateway Green Energy Holdings LLC	Dec-2011	30	May-2011	May-2011	Announced
Desert Wind Power Project	NC	Wind	Wind Turbine	Iberdrola Renewables Inc.	Oct-2012	300	Jun-2011	Jun-2011	Advanced Development
Dixon Dairy Road Solar Project	NC	Solar	Solar: Photovoltaic	Strata Solar LLC	Dec-2011	5	Apr-2011	Apr-2011	Announced
Gaston County	NC	Biomass	Internal Combustion	Gaston County	2011	5	Jun-2011	Jun-2011	Construction Begun
Green Mountain Solar Project	NC	Solar	Solar: Photovoltaic	Clean Energy Pathways Inc.	NA	4	Apr-2011	Apr-2011	Announced
GrowGreen Co-Generation Plant	NC	Biomass	Steam Turbine: Boiler	GrowGreen Power Inc.	Aug-2012	44	Jun-2011	May-2011	Announced
Hopewell - Polyester	VA	Coal	Steam Turbine: Boiler	Virginia Electric and Power Co.	Dec-2013	NA	Jul-2011	Apr-2011	Announced
Jet Assembly Solar Plant	SC	Solar	Solar: Photovoltaic	South Carolina Electric & Gas Co.	2011	3	Apr-2011	Apr-2011	Announced
Richmond Energy Project	VA	Biomass	Internal Combustion	Fortistar LLC	Nov-2011	6	May-2011	May-2011	Construction Begun
Southampton VA	VA	Coal	Steam Turbine: Boiler	Virginia Electric and Power Co.	Dec-2013	NA	Jul-2011	Apr-2011	Advanced Development
Suffolk Landfill	VA	Biomass	Combustion Turbine	GPC Green Energy LLC	Feb-2012	20	May-2011	Feb-2011	Construction Begun
Sutton CC	NC	Gas	Combined Cycle	Carolina Power & Light Co.	Dec-2013	625	Jul-2011	May-2011	Construction Begun
William States Lee III Nuclear Station	SC	Nuclear	Nuclear: PWR	Duke Energy Carolinas LLC	2021	2,234	Jun-2011	Feb-2011	Advanced Development

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