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Electric Utility Week

February 21, 2011

Geomagnetic storms flare up, put utilities on guard, as NERC announces task force

As experts appeared last week in Washington to warn state energy regulators of the high probability of geomagnetic storms associated with solar flares that could damage the power grid, the National Oceanic and Atmospheric Administration said the sun was exiting a period of calm and issued an advisory about a geomagnetic storm.

And North American reliability officials announced a new task force charged with improving the ability of the grid to withstand low-frequency, high-impact events like geomagnetic storms and malicious electromagnetic pulse attacks.

The likelihood of such events, at least those of natural origin, is high, experts say. Avi Schnurr, president of the Electrical Infrastructure Security Council, told a Washington meeting last week that statistically, severe geomagnetic storms occurring, on average, once every 100 years are "basically a certainty, it depends how long we have." Such storms, associated with coronal mass ejections from the sun, could create outages lasting five to 10 years.

And because of increasing digitization, automation and ini-

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Message keeps coming: Utilities can handle EPA rules, and agency not out to 'punish'

Coal-fired utilities are pleading for more time to meet what they call an unprecedented level of environmental regulation, but at least some financial analysts expect utilities will recover their environmental control investments and suggest that delay is not necessarily a good thing.

"Rate-based growth of fair regulation translates into better earning power for utilities," said Dan Eggers, Credit Suisse managing director of US power and electric utilities.

Under the Environmental Protection Agency's new regulatory regime, utilities that have already invested to clean up their supply portfolios will be rewarded in the energy markets, and those that have to spend capital to meet the rules should recoup costs through their rate bases, as has been the precedent, Eggers said.

Even as Republicans in Congress, particularly the House, appear headed to blocking EPA's new and upcoming greenhouse gas control rules in some way, some see the prospect of all the regulation as less dramatically onerous than others do.

"The expectation would be that the regulated utilities would be able to get recovery on the capital they invested in environ-

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Experts advise expanded use of securitization by utilities to finance range of cost recovery

Customers would benefit if electric utilities significantly expanded use of securitization, a "powerful financing tool" that regulators and others said last week gives flexibility in paying for such big-ticket items as environmental mitigation, nuclear plant cost overruns and smart grid installations.

So far, however, securitization has generally been limited to cost recovery for such non-routine events as hurricanes.

Securitization bonds, also known as ratepayer obligation charge bonds, typically get high credit ratings because debt service is covered by legally committed revenue streams from retail rate surcharges. Securitization provides utilities with immediate cost recovery once the bonds are sold, instead of the gradual cost recovery they would see through a rate rider not tied to the bonds.

But ROC bonds traditionally have seen only limited use by utilities because of utility reluctance to remove assets from rate base. Instead, securitization has been used in recent years mostly for recovery of costs associated with major storms in the South and in Texas for stranded cost recovery tied to deregulation.

Until last week, that is, when Entergy Louisiana said it

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EPA greenhouse gas program would be axed by House spending bill; Senate fate uncertain

The House of Representatives was poised Friday to strip the Environmental Protection Agency of its authority to regulate greenhouse gases and reduce the agency's budget by more than $3 billion, as part of a bill funding the federal government for the rest of fiscal year 2011.

As of Friday afternoon, the measure was still unfinished after four days of wide-ranging debate on more than 580 amendments, with a vote expected Friday night or Saturday. The so-called continuing resolution would take effect March 4, when an existing CR ends, and would fund federal programs through September 30.

If the CR becomes law, it could cause major uncertainty for industries about how EPA greenhouse gas regulations will be enforced, said Bill Becker, executive director of the National Association of Clean Air Agencies. Because the CR would not change the underlying regulation, some companies seeking EPA permits requiring pollution control technology would be essentially blocked from starting their projects.

"In close to 10 states they will face a *de facto* construction ban, where the federal government issues the permit and there is no funding," Becker said. "It also creates a tremendous amount of uncertainty in states where they themselves issue the permits because there's no technical assistance, there's no guidance, there's no resolution to any kind of environmental appeal should it occur, so there's never really total certainty with regard to federal agency support should a state act on its own."

Frank Maisano, an energy policy specialist at the Washington law firm Bracewell & Giuliani, argued that an amendment by Texas Republican Representative Ted Poe that passed Friday would essentially reverse the EPA's underlying authority and prevent a *de facto* construction ban.

Becker disagreed that Poe's amendment would solve the permitting problem. "The amendment still leaves the underlying requirements in effect. It merely takes away EPA funding to implement them," he said.

But Maisano said Poe's amendment has the support of industries that oppose the EPA climate regulations and would be affected by a permitting ban. "There's a pent-up frustration that EPA is going around Congress to regulate greenhouse gases," Maisano said. "They're looking for an opportunity to rectify that problem."

Among scores of other changes to federal energy programs and policy, the bill also would also cut billions from federal energy research, heating aid and environmental oversight budgets.

The White House threatened to veto the fiscal 2011 spending bill, saying proposed spending cuts would hurt the country's ability to "out-innovate the rest of the world."

The bill faces dim prospects in the Senate, which is expected to begin debate the week of February 28. Democratic leaders there said they would not accept the deep spending cuts set by the House.

If lawmakers do not reach an agreement and pass a spending bill by March 4, most federal operations would shut down.

House Speaker John Boehner, an Ohio Republican, ratcheted up tension over a possible shutdown, in a press conference Thursday. Boehner said he would not pass a stopgap spending measure that would give lawmakers more time to negotiate a bill for the rest of fiscal 2011.

"I am not going to move any kind of short-term CR at current levels," Boehner said. "When we say we're going to cut spending, read my lips, we're going to cut spending."

The measure would cut several Department of Energy research and loan programs compared with the Obama administration's 2011 budget request. DOE's Office of Science would receive $1.1 billion less than Obama's request, while the Office of Energy Efficiency and Renewable Energy would see an $899 million cut.

The bill gives ARPA-E, which funds high-risk, high-reward energy research, $50 million for the remainder of 2011 — $250 million less than requested by President Barack Obama in his 2011 budget request. The 2009 stimulus bill gave the program,

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GENERATION

Duke's Rogers says 'bias' is to sell 7,000 MW of Ohio assets; says regulatory model 'broken'

Duke Energy, hemorrhaging retail electric customers and frustrated by an Ohio regulatory system it believes is deeply flawed, is leaning towards divesting more than 7,000 MW of coal-fired generating assets controlled by its Duke Energy Ohio subsidiary instead of operating them on a merchant basis.

James Rogers, chairman, president and CEO of the Charlotte, North Carolina-based company, said during a February 17 earnings conference call, "the regulatory model in Ohio is broken and we need to find a way to revise it." He was referring to S.B. 221, the state's 2008 electric restructuring law that ushered in a pair of rate plan choices for investor-owned utilities: An electric security plan, a form of re-regulation, or a market rate option, both of which must be approved by the Public Utilities Commission.

In endorsing only ESPs so far, the commission has eschewed MROs, claiming they represent more of a rate risk for consumers. Duke Energy Ohio is seeking approval for a market plan, but the PUC staff earlier this year recommended its rejection "in its entirety" (*EUW*, 7 Feb, 20). Duke's existing three-year ESP expires at the end of 2011.

Duke Energy Ohio clearly has not fared well under the three-year-old law. The utility has lost more than 60% of its load to competitive suppliers who have been able to undercut Duke Energy Ohio's prices, although the company says retail customer switching began to stabilize in the third quarter of 2010.

Under an MRO, the price of power from Duke Energy Ohio's generating fleet would shift to pure market-based rates by June 2014. The utility owns 6,080 MW of "scrubbed" coal-fired capacity, as well as 1,336 MW of "unscrubbed" coal capacity.

Rogers said Duke Energy Ohio is suffering from "asymmetrical risk," explaining the utility's generating assets "currently serve an essentially regulated function in that they must stand ready to serve our retail customers. However, under the ESP structure, we are not adequately compensated for this obligation."

The proposed MRO, he said, "would eliminate some of the asymmetrical risks we now experience under the ESP framework. Our MRO is designed first to give us flexibility to deliver competitive and fair rates to customers; secondly, to provide mechanisms that give us opportunities to earn more adequate returns on our investments in Ohio; and lastly, to provide more long-term clarity for our Ohio generation business."

The MRO is "the best option available given the commission's position on the ability to get a non-bypassable charge that allows us to earn a fair return on the generation that we're required to have on standby to provide power if and when customers come back," he added. "In a sense, customers in Ohio have a free option, and as you know in commercial markets there are no free options. So we need to get the rules right."

Under Ohio law, the commission must issue a final order on Duke Energy Ohio's application by the end of February, although the timetable could be extended under certain circumstances.

In the coming weeks, he said, the company plans to file a request to transfer its Ohio coal generating assets to an affiliate of Duke Energy Ohio, providing Duke with more flexibility for its future generation. While no final decision has been made, Rogers said his current "bias" would be to eventually sell those assets rather than operate them as merchant facilities.

Duke first publicly broached the notion of selling the plants last fall (*EUW*, 27 Sept '10, 9), confirming a divestiture was among several options on the table.

Nationally, wholesale power prices have been slumping because of the extended economic downturn. In Ohio, meanwhile, Duke's residential electric rates are among the highest in the state — about 14 cents/kWh, a factor that has weighed heavily in the migration of its customers to competitive suppliers.

Supporters of electric competition argue the Ohio law is working as intended and is benefitting consumers.

"Ohio consumers are seeing the benefits of competitive markets, which transparently reflect record low fuel prices, new innovations like demand response, and broad access through organized markets like PJM and MISO," said Joel Malina, executive director of the Compete Coalition, a group of 540 electricity stakeholders, including customers, suppliers, generators, transmission owners, trade associations, environmental organizations and economic development corporations.

Under the existing regulatory paradigm in Ohio, the risk is on shareholders, not consumers, Malina maintained. "Consumers appreciate the ongoing effort of Ohio regulators and FERC [the Federal Energy Regulatory Commission] to ensure that well-functioning wholesale and retail markets continue to benefit Ohio consumers."

Alicia Moran, spokeswoman for the Retail Energy Supply Association, a trade group, said RESA did not "feel comfortable" commenting on Rogers' remarks because its top officials had not heard them.

— Bob Matyi, Housley Carr

Washington seeks answers on power outages, as FERC launches inquiry, Senate sets hearing

The fallout from the power and natural gas outages in Texas and the Southwest reached Washington last week, with the Federal Energy Regulatory Commission launching a staff inquiry into the events and the Senate Energy and Natural Resources scheduling a hearing.

The Senate committee will hold a field hearing Monday in Albuquerque, taking testimony from officials with FERC, the North American Electric Reliability Corp., the natural gas and power industries and elected officials.

The hearing will examine natural gas supply disruptions in New Mexico and elsewhere, and the reliability of energy infrastructure in the region, the committee said late last week.

In addition to representatives from the interstate pipeline sector, the Electric Reliability Council of Texas and local elected officials in New Mexico, US House of Representatives members Ben Ray Lujan and Martin Heinrich, both Democrats from New Mexico, will testify, according to the committee, which is chaired by Senator Jeff Bingaman, Democrat from New Mexico.

With unusually cold weather across the nation during the first week of February, "the bulk power system in Texas and Arizona experienced a significant number of outages at generating facilities during a period of high demand for electricity from its customers," FERC said in its February 14 order (Docket No. AD11-9). Also, "deliveries of natural gas were disrupted in Texas, New Mexico and elsewhere in the Southwest," it said, noting that the outages "affected many customers throughout the region."

The interdependence of gas and electricity came into play during the cold snap, especially in Texas, where gas pipeline compressor stations powered by electricity were shut down, and thus were unable to feed gas-fired power plants, further exacerbating the problems.

In Texas last week, more than a dozen elected officials who grilled power industry representatives on Tuesday expressed frustration over the events that led to widespread power outages and statewide rolling blackouts early this month, but rallied around a common theme: fix the problems.

The Texas Senate Committee on Business and Commerce and the Senate Committee on Natural Resources jointly hosted in Austin a hearing at which 14 representatives from government and regulatory entities, generators, wires companies and natural gas producers and distribution companies offered their views on the events of February 2.

That day, sub-freezing temperatures, snow, sleet and ice knocked out 82 generating units, or about 15% of ERCOT's total units, with more than 11,000 MW of capacity, at different times throughout the day. "We've got to figure out a way to somehow incentivize the generators to be prepared. Eighty-two outages, I think, is unacceptable," said state Senator Troy Fraser, the Republican chairman of the Committee on Natural Resources.

"I know we had a cold night and it was an unusual event, but they have a lot of cold nights in the East and a lot of these generators operate in both places," he said.

ERCOT CEO Trip Doggett reiterated the main factor he has given over the past two weeks: that inadequate weatherization was the major culprit in knocking generating units offline or preventing them from coming online. Problems did not affect any one type of generation or plant units of any particular age.

Many committee members expressed disbelief that generators could not have prepared for weather conditions that appear with more regularity elsewhere in the country. However, "if you tried to insulate, confine and surround our units like they do up there then that boiler platform in the middle of August is going to be around 100 degrees," said Barry Smitherman, chairman of the Public Utility Commission of Texas.

While FERC has jurisdiction over the interstate pipeline sector, the Railroad Commission of Texas has jurisdiction over the state's oil and natural gas sector, including intrastate pipelines. RRC Chairman Michael Williams agreed with his counterparts at ERCOT and the PUC that February 2 "was not a gas issue for those with firm contracts." Still, power generators that had interruptible contracts for natural gas — in which they might pay less for natural gas but with the knowledge it could be interrupted — did have supply issues, though how many is not yet known.

The supply issue was affected by a nearly 40-year-old RRC rule that Fraser called "unacceptable." The 1972 rule, Docket No. 489, states that during a natural gas shortage, supply to power generators will be cut off in favor of supplying the public. In this event, Fraser noted, electricity could be shut down, which would then affect electric compressors that pump the natural gas. "I think the commissioners have been well advised that it is in the interest of this body to rethink Docket 489," Williams said.

Looking at information available so far, Smitherman said, there does not appear to be any malfeasance or market manipulation, but he noted that ERCOT's independent market monitor, Potomac Economics, has been asked to look into possible attempts at gaming or manipulation. That report is due by April, but Smitherman said he would push to expedite its progress.

FERC staff would have subpoena power

Along with state agencies and NERC, FERC decided to delve into the situation. FERC staff will attempt to identify the causes of the service disruptions and then "identify any appropriate actions for preventing a recurrence of these disruptions." The commission made clear that it was "not at this time initiating an investigation into whether violations of applicable regulations, requirement or standards under the commission's jurisdiction may have occurred."

Its priority "at this moment is to gather the relevant facts, identify the problems and fix them, to the extent possible."

Staff will have subpoena power and authority to compel the production of documents and records "in order to bring the inquiry to a resolution as promptly as possible," said the order. "Any decisions on whether to initiate enforcement investigations will be made later," it added.

FERC noted that its jurisdiction included oversight of NERC, but "is also broader than NERC's role in these circumstances." FERC has responsibilities and authorities under the Natural Gas Act and Natural Gas Policy Act "that apply here beyond and apart from any effects on the bulk power system."

At the February 17 FERC meeting, Chairman Jon Wellinghoff emphasized that the commission was not conducting an enforcement action, but rather was intent on gathering enough information to determine whether such an investigation is warranted.

He added that FERC was "uniquely situated to oversee this inquiry" thanks to its dual power and gas jurisdiction, and that he had been in contact with several state regulators about coordinating fact-finding efforts.

For his part, Commissioner John Norris related that he was in Texas during the outages. "I'm sympathetic to what folks in Texas went through," he related, adding that "health and human safety" had been placed "at risk," while businesses "lost business." Under such circumstances, it is common for "the blame game" to start, Norris said. But pointing fingers "doesn't help address any of the problems," he said.

— Chris Newkumet

Three Southwest coal plants totaling 6,090 MW facing greater EPA scrutiny and other issues

Regulators and others took steps last week to help determine the fate of three southwestern coal-fired plants whose combined capacity totals 6,090 MW.

The three stations — the San Juan, Four Corners and Navajo plants — face similar challenges, including pending Environmental Protection Agency requirements aimed at cutting regional haze, expiring leases and California utility owners limited by state law in investing in coal plants.

In New Mexico, EPA held public meetings February 17 in Farmington on its proposal to add selective catalytic reduction equipment to the San Juan plant. PNM Electric, which operates the 1,800-MW plant, strongly opposes the plan, and said last week that it will not improve visibility in the region though costing about $750 million. The San Juan County Commission approved a resolution last week opposing EPA's plan because it said it could hurt the local economy.

Environmental and other groups, however, urged EPA to move ahead, partly out of concerns that emissions from the plant are hurting people and the environment.

Meanwhile, the Navajo Tribal Council last week approved extension of a lease for the 2,040-MW Four Corners plant near Farmington, a key requirement in Arizona Public Service's plan to shut the three oldest units totaling 550 MW.

Phoenix-based APS proposed retiring them by 2014 while buying Southern California Edison's 739-MW share of the remaining two units for $294 million. APS expects to spend another $315 million adding pollution control equipment to the remaining units by 2018.

EPA said the utility plan was more effective and less expansive than the agency's October proposal to add SCRs (*EUW*, 11 Oct '10, 17): It would lower the plant's nitrogen oxide emissions by 87%, compared with 80% under EPA's proposal, the agency said February 11.

The Four Corners plant has six owners: APS, SCE, PNM, Salt River Project, Tucson Electric Power and El Paso Electric.

EPA is taking comments on APS' proposal in addition to its October proposal until May 2. It also plans to hold public hearings in the Four Corners area during the week of March 28.

In Arizona, a stakeholders group met February 18 to hash out a vision for the 2,250-MW Navajo plant. The effort was organized by SRP, the Phoenix-based public power utility that operates the plant in Page.

The group hopes to reach "a widely accepted agreement" on how to best cut NOx, particulate matter and hazardous air pollution from the Navajo plant. SRP expects the agreement to serve as a "foundational document" for a best available retrofit technology determination by EPA and as a basis for other possible actions by plant owners, public agencies and interested parties, according to EN3 Professionals, a consulting firm that is running the stakeholders process.

The Navajo plant has six owners: the US Bureau of Reclamation (547 MW), SRP (488 MW), Los Angeles Department of Water and Power (477 MW), APS (315 MW), NV Energy (254 MW) and TEP (169 MW). LADWP plans to divest its 21.2% share by 2014.

While the Navajo plant supplies baseload power to utilities in three states, it also is used to run pumping stations for the Central Arizona Project, which supplies about 20% of the water in Arizona.

The EPA started a rulemaking process on regional haze issues related to the plant. It tentatively recommended that SCR equipment be added to cut NOx. The agency is expected to issue a proposal for Navajo this summer.

The utilities that own the three plants all have argued that SCRs offer little or no benefit to air quality compared with less expensive options. SRP estimates it would cost $544 million to add the SCRs to the Navajo plant and $1.13 billion to add SCRs and baghouses.

— Ethan Howland

Connecticut governor proposes $58 million tax on generation to help reduce budget deficit

Connecticut for the second year is looking to the electricity sector to help close a state budget deficit, this year through a tax on generation new Governor Dan Malloy hopes will raise $58 million.

Malloy, a Democrat, proposed the tax to help close a $3.2 billion deficit when he unveiled his $18 billion annual state budget proposal last week. The tax would be 0.2 cents/kWh generated.

The idea drew immediate outcry from generators and businesses, which said it will lead to higher electricity costs in an already pricey state. Connecticut's rates average 17.42 cents/kWh across all customer classes, second only to Hawaii, where rates are 25.03 cents/kWh, according to the Energy Information Administration.

Angela O'Connor, president of the New England Power Generators Association, said the new tax would raise rates without bringing in the revenue Malloy expects.

"The new cost of doing business will cause the state's plants to run less, leading to lower income tax and property tax revenue, and not even coming close to producing $58 million in new revenues. The proposed generator tax is a classic lose-lose proposal," O'Connor said.

Last year, Connecticut helped close its budget gap by continuing a utility stranded-cost charge set to expire and using the money to securitize a $1 billion bond.

"Electricity rates were part of the mix last year and they are

(continued on page 7)

PLANTS AND PROJECTS

Tessera Solar February 16 said it sold its 709-MW Imperial Valley solar project to joint venture **AES Solar**. Plant development has been held up by a Native American group which opposes it because it crosses traditional lands. "AES Solar intends to move the project forward and is committed to working with **San Diego Gas & Electric** to fulfill its obligations under the power purchase agreement," Tessera said in a statement. Tessera did not disclose a sales price for the purchase by the joint venture of **AES Corp.** and **Riverstone Holdings**. It referred additional questions to AES Solar, whose spokesperson was not available for comment. A US Magistrate in San Diego in early January ordered the tribal council of the Quechan Tribe of the Fort Yuma Indian Reservation to begin settlement talks over its opposition to the development. Talks were postponed from February 14 to March 3. The tribe had won a preliminary injunction halting the project from a US district court judge December 15. The Imperial Valley project is planned on about 6,500 acres of federally owned land known as the **California Desert Conservation Area**. The **Department of Interior** manages the area. The tribe said the project will cross its "traditional territory" that "contains cultural and biological resources" of significance. This sale also comes after Tessera sold in late December its largest and fully permitted proposed solar installation — the long-planned and long-delayed 850-MW Calico plant in California.

... Environmentalists appealed an air permit issued by the **Ohio Environmental Protection Agency** for **Dayton Power & Light**'s plans to burn biomass with coal at the 600-MW Killen coal plant near Wrightsville in Adams County. DP&L, a subsidiary of **DPL Inc.**, can use a 7% blend of sawdust and grass with coal under the permit approved December 29. Although the permit says "clean cellulosic biomass" would be used, three groups — **Sierra Club**, **Ohio Environmental Council** and **Buckeye Forest Council** — remain skeptical. So they appealed the permit to the Ohio **Environmental Appeals Commission**, which handles appeals from Ohio EPA. "The permit issued did not adequately take into account potential emissions of various pollutants from biomass and did not identify the kinds of biomass to be used," maintained Nachy Kanfer, Midwest representative for Sierra Club's Beyond Coal Campaign. "Also, while this might back out some coal, the reality is this will add a revenue stream to a coal plant." That is because DP&L would receive potentially lucrative renewable energy credits for using biomass at Killen. DP&L said it is attempting to comply with Ohio's 2008 renewable portfolio standard law, S.B. 221, that requires utilities to get at least 25% of their power by 2025 from traditional renewables such as wind and biomass and advanced energy like clean coal and nuclear. It also includes a small carve-out for solar. Because ERAC appeals can take up to two years to resolve, Kanfer conceded that could make the challenge something of a moot point.

... Geronimo Wind Energy asked the **Minnesota Public Utilities Commission** for permission to double a proposed wind farm to up to 200 MW to take advantage of market conditions. Geronimo, based in Edina, Minnesota, in May asked for permission to build the 101-MW Prairie Rose wind farm in the southwestern part of the state. "Since that time, however, increasing constraints in the Midwest ISO system, have created additional near-term market opportunities for projects such as Prairie Rose, that have a combination of available transmission access and strong wind resources," the company said in a filing with the PUC. Also, Geronimo said, extension of federal incentives for renewable energy allow the project to provide competitively priced power. The developer has over 27,300 acres under lease in the project area with over 200 participating landowners. The developer plans to use either **General Electric** or **Vestas** turbines, allowing the wind farm to produce power with a 42.6% to 45.7% capacity factor, up somewhat from its original estimate. The larger project would cost $330 million to $350 million, or $1.65 million/MW to $1.75 million/MW. Reflecting a drop in wind power prices since the first application, federal incentives and economies of scale, the larger project would cost about $310,000/MW less than the original request, according to the company. Geronimo plans to start construction late this year and bring the wind farm online by 2013. In late 2009, **Enel North America** took a minority stake in Geronimo, which is developing roughly 4,000 MW in the northern Midwest states. Not counting the Prairie Rose project, Geronimo has five projects in advanced development stages in Minnesota totaling 250 MW (nameplate).

... The **Environmental Protection Agency** has until mid-April to decide whether to formally object to a draft clean air permit issued for an aging 626-MW coal plant in western Pennsylvania. The **Sierra Club**'s Pittsburgh chapter February 14 asked EPA to object to the draft operating permit issued in the fall by the **Pennsylvania Department of Environmental Protection** for the Shawville plant. The plant is owned by **GenOn Energy**, the Houston-based company formed by the merger of **Mirant** and **RRI Energy**. The draft permit fails to comply with the requirements of the Clean Air Act and the Pennsylvania site implementation plan, the Sierra Club said. It asked EPA to require DEP to modify the draft permit to include adequate compliance methods required by the federal law. EPA and the Sierra Club filed comments on the draft, Jamie Legenos, a spokeswoman for the DEP, said. EPA recommended that the draft be more specific in monitoring requirements for sulfur dioxide, nitrogen oxides and CO_2 to meet CAA requirements, Legenos said. Shawville's four units came online between 1954 and 1960. GenOn now owns the plants, but it was RRI Energy Mid-Atlantic Power Holdings that applied for a new operating permit in April. Meanwhile, **PennFuture**, an environmental public policy group, on January 28 asked the EPA to object to the draft permit for another GenOn plant — the 637-MW Cheswich power station in Springdale. The draft permit does not impose limits on mercury emissions and does not apply to the ash disposal site associated with the plant, PennFuture said. GenOn is still reviewing the Sierra Club's and PennFuture's requests to EPA, spokesman Mark Baird said.

... Duke Energy Indiana still needs the capacity and energy to be provided by its 618-MW integrated gasification combined-cycle project in Edwardsport, and is striving to complete the project within its $2.88 billion estimate despite upward pressure on

PLANTS AND PROJECTS

costs, Duke Energy Chairman, President and CEO James Rogers said. "[S]everal groups have opposed the continued use of coal in general and Edwardsport in particular, [and] have raised objections to both the plant and its revised cost estimate," which replaced Duke's earlier estimate of $2.35 billion, Rogers said during the 2010 earnings conference call February 17. "Although estimated construction costs have increased over the original estimate, our [integrated resource plan] analysis confirms that we need additional capacity and completing the plant is the best solution for our customers," he added. Duke and other utilities may need to shut down roughly one-third of their older coal capacity by 2020 as environmental rules tighten, and that "due to the long lead times required" to build new baseload capacity projects like Edwardsport must be built now, Rogers said. The IGCC project in Edwardsport was 80% complete at the end of last year, and is scheduled to begin commercial operation in the summer of 2012.

... **CMS Energy** plans to invest $1.5 billion in environmental upgrades at several of its largest coal-fired power plants. "We have some very large plants, on the coal side, and we need them for the capacity and the low-cost baseload generation," Thomas Webb, executive vice president and CFO, said during his presentation at the **Credit Suisse** Energy Summit February 8. "They are hands-on great facilities to have." Webb did not identify the plants in question, but a CMS spokesman later confirmed they include four baseload coal plants: 2,100-MW Karn-Weadock, 1,450-MW J.H. Campbell, 328-MW Whiting and 320-MW Cobb. Webb was asked about the rationale for such expenditures when the **Midwest Independent Transmission System Operator** currently has excess capacity. "These are sound investments, and we will need that capacity and it will provide the lowest-cost service to our customers or we wouldn't do it," Webb replied. "On the existing plants, it's a terrific thing to do." Last year, he noted, CMS deferred plans for a new 830-MW baseload coal plant at the Karn-Weadock site at Bay City because of declining electric sales and lower natural gas prices. "We did say 'deferred' because we are watching that spot and it may turn out to be one of the better investments in the future." The new plant is estimated to cost about $2.3 billion. Michigan's new Republican governor, Rick Snyder, is thought to be more supportive of new coal plants than his predecessor, Jennifer Granholm, a Democrat.

... **Wind Capital Group** is in the early stages of developing a 150-MW wind farm in Palm Beach County, Florida, that could begin commercial operation as soon as late 2012, the St. Louis-based wind developer said. The proposed $250 million wind farm would be the first utility-scale project of its type in Florida. Wind Capital Group, which has developed several wind farms in the Midwest, believes improvements in wind-turbine technology and lower turbine costs make the development of wind farms feasible in areas such as southern Florida where wind resources are considerably less robust, said spokesman Tony Wyche. The turbines for the Palm Beach County project would be sited on more than 10,000 acres of agricultural land now used for growing sugar cane, Wyche said. Farming operations would continue without major effect, he said. Wyche said Wind Capital Group has held preliminary discussions with potential offtakers, but he did not name them. Palm Beach County is served by **Florida Power & Light**, whose affiliate, **NextEra Energy Resources**, is the nation's largest wind farm developer. Wind Capital Group also has been meeting with local officials and environmental groups to discuss the Florida project.

... **Constellation Energy** plans to buy a 7.8-MW solar photovoltaic project in New Jersey from developer **Community Energy**, the companies said. Terms of the deal were not disclosed. The electricity is to be sold to the Vineland, New Jersey, municipal utility under a 25-year power purchase agreement obtained by Community Energy and assigned to Constellation's retail business. Constellation would finance as well as build and operate the solar installation that would be among the three largest in New Jersey, which is second to California in terms of installed solar capacity. The project is to be ground-mounted on two sites in Vineland, totaling about 40 acres, and is expected to generate about 1,000 GWh/year. It is slated to be online this summer. With this project, Constellation has completed or has under construction 60 MW of solar nationwide, according to spokeswoman Kelly Biemer.

(continued from page 5)

unfortunately getting dragged back into it this year," said Kevin Hennessy, assistant counsel for the Connecticut Business and Industry Association.

Hennessy said his organization is concerned because generators are large employers in Connecticut, and are likely to be less competitive regionally with the tax in place. No other state in ISO New England taxes generators.

In addition, he said the tax will be passed on to businesses that are already shouldering the added stranded-cost payments. For some CBIA members, the stranded-cost charge adds "tens of thousands of dollars" to their annual electricity bill, he said.

O'Connor said that ratepayers also have been strapped with high transmission costs because of new infrastructure built in the state.

Generation costs have dropped recently, but a new tax would reverse that trend, according to O'Connor. "After years of paying for transmission infrastructure investment, most Connecticut ratepayers realized real rate relief this year. To now take that rate relief back by adding at least $60 million to the ratepayer's bill does not make sense," O'Connor said.

Malloy's office did not immediately return phone calls. However, in a prepared statement, Malloy said he proposed $1.5 billion in new taxes in all.

"I've spoken at length about shared sacrifice, and I think this budget explains what that means — I'm asking for a little from everyone to avoid overburdening any one group," he said.

Malloy pegs the budget deficit at $3.2 billion, the ninth worst in the nation.

The budget now goes before the joint Appropriations

Committee of the Connecticut General Assembly. Malloy is working with a Legislature that is also controlled by Democrats.

— Lisa Wood

Michigan regulators approve air permit for 78-MW Holland coal plant

A Michigan state agency reconfigured under new Republican Governor Rick Snyder is moving quickly to reverse former Governor Jennifer Granholm's outspoken opposition to new coal plants.

The Department of Environmental Quality, once again a stand-alone agency after a Snyder edict split it from the Department of Natural Resources, issued a long-awaited air permit for the Holland Board of Public Works' proposed 78-MW baseload coal plant, essentially an expansion of the city's 60-year-old James DeYoung coal plant.

Last August, the Department of Natural Resources and Environment denied the permit application after concluding the power was not needed. The decision was based on Granholm's February 2009 executive order, largely viewed as a *de facto* moratorium on new coal plant applications. Holland appealed to the Ottawa County Circuit Court (*EUW*, 6 Sept ' 10, 14). Late last year, Judge Jon Van Allsburg ruled the state had overstepped its legal boundaries and remanded the permit case back to the state agency.

The permit clears the way for Holland, a city of 35,000 near the eastern shore of Lake Michigan, to construct a $250 million plant in the planning stages for several years. The initial permit application was filed with DEQ in January 2007, during the administration of Granholm, a Democrat whose two, four-year terms ended at the close of 2010.

In issuing the permit, DEQ spokesman Brad Wurfel said the agency plans to "continue to work with the city of Holland and EPA" on the issue. "EPA has changed some of its guidelines between the time the permit was supposed to be issued in August and now."

Loren Howard, general manager of Holland Board of Public Works, praised the DEQ's about-face. "Over the past month and a half, we've worked cooperatively with the DEQ here in Michigan and the Snyder administration has been very responsive," he said. "The administration has a different take on what the state is allowed to do" in terms of approving new coal plant applications.

The city is conducting an independent energy evaluation, he said, and a final decision on constructing the plant probably will come by the end of this year. It is possible the plant also could burn wood waste and/or tire-derived fuel in addition to coal, he said. Holland also is considering "a combined heat and power project that would produce district heating as well as electricity," Howard said.

Wurfel said his agency is poised to issue a final air permit for Wolverine Power Cooperative's 600-MW coal plant proposed for Rogers City. That application also was denied last year by the DEQ, and another judge overturned the ruling in January.

Wurfel said the DEQ has been in contract with Wolverine, a Cadillac-based generation and transmission co-op, and is waiting for Wolverine to say it still wants the permit for the $2.5 billion baseload project.

— Bob Matyi

TRANSMISSION

Big-region transmission planners identify challenges, including funding uncertainty

Uncertainty is the watchword for transmission planning in 2011, participants in interconnection-wide planning processes said last week, noting the challenges presented by changing regulations, policy perspectives and competing stakeholders.

Part of that uncertainty is financial, as members of the Eastern Interconnection Planning Collaborative expressed concerns about what will happen once the government stimulus funding used to launch the group is gone in a few years. EIPC is one of the major transmission planning efforts going on at an interconnection-wide level.

Kevin Gunn, chairman of the Missouri Public Service Commission and a member of the EIPC Executive Committee, said transmission planning is a challenge, with many different fuel types and regions that have varying perspectives and needs.

The interconnection-wide planning process is "almost like a constitutional convention for transmission planning," he said, where stakeholders must consider broader perspectives and compromise their local needs or needs of their states for the greater good.

"In some ways you may need 'founding father' moments," he said, when decisions must be made based on what is better for a broader region. Gunn, on a panel at the National Electricity Forum in Washington, said stakeholders might have their own financial or policy objectives, but in the interconnection-wide process "we have to put some of that aside, and come to a compromise, and push people in the right direction."

Panelists discussed the challenges facing the Federal Energy Regulatory Commission as it develops rules on transmission planning and cost allocation, as well as uncertainties faced by participants in the Department of Energy-funded interconnection-wide planning processes happening in the Eastern and Western interconnections.

David Whiteley, a consultant with the EIPC, said the group is dealing with the uncertainty by performing a number of analyses based on various future scenarios, including those involving carbon constraints, renewable portfolio standards and other issues that can affect transmission, such as energy efficiency and demand response.

"We are not focused on one particular view of the future," Whiteley said. "We are starting with really a wide view with a lot of data points in it." The problem, he said, "is trying to figure out what to do with all the information."

FERC commissioner and panelist Cheryl LaFleur said that over her 25 years of industry experience there has always been major uncertainty, even though planners often think the climate they are functioning in is the most uncertain in history. Uncertainties include changing public policies such as renewable electricity standards and emerging energy resources and technologies, she said.

LaFleur said state and federal policy makers "are lucky to be involved in delivering an absolutely essential service that people need. We are just going to have to deal with the uncertainty."

EIPC concerned about funding

The EIPC and a separate but related grid planning effort involving state regulators, the Eastern Interconnection States Planning Council, have been meeting and using $30 million in stimulus funding to study and inform policymakers on the cost, environmental attributes and other factors involved in transmission planning across the entire interconnection.

"I hope funding continues," but it will be tough to count on federal money given the serious budget concerns, said Charles Gray, executive director of the National Association of Regulatory Utility Commissioners. Gray and others commented on the effort at NARUC's winter committee meetings in Washington and the National Electricity Forum.

Douglas Nazarian, chairman of the Maryland Public Service Commission and vice president of the EISPC, noted that as new entities with a broad scope, the groups' findings will inform regulators, but will not be too specific on what plans to follow. "It is not going to result in a map, or a list of projects to build," he said.

Grid planning on a broader scale will be needed to carry out national energy goals, but at this point the work still is in the early stages, and it is facing some challenges, Nazarian said. Besides the funding concerns, meeting what may be too-high expectations for the groups' results may be a concern, he said.

"We are taking a broad look at a variety of cases," such as use of renewable resources closer to populous areas rather than building transmission lines to carry that power long distances, and it marks the first time such planning has been done beyond the boundaries of regional transmission organizations in the Eastern Interconnection, Jon McKinney, a member of the West Virginia Public Service Commission, pointed out.

"I can't change expectations," but EISPC is not going to be putting lines on a map for the industry to build, he added.

State regulators are accustomed to integrated resource planning within their borders, and even that process can drag out and involve questions about environmental attributes of renewable resources, costs associated with tapping those resources and adding transmission lines, panelists said at the NARUC committee meeting. Carrying that out on the broad scale envisioned by the EIPC and EISPC has never been done before, but "I'm anxious to see how it all comes together," said Steve Whitley, president and CEO of the New York Independent System Operator.

— Jason Fordney

Senate bill, led by Corker, challenges FERC on approach to transmission cost allocation

A bipartisan group of senators introduced a bill last week intended to ensure that consumers are not forced to pay for new power lines "for which they receive no direct or meaningful benefit."

Offered by Republican Senators Bob Corker of Tennessee, Lisa Murkowski of Alaska, Richard Burr of North Carolina and Lindsey Graham of South Carolina, along with Democrat Ron Wyden of Oregon, the legislation is aimed at FERC's pending rulemaking on transmission planning and cost allocation.

Designed to help expand and modernize the national grid, the commission's proposed rule (Docket No. RM10-23) would encourage interregional planning of infrastructure, ensure that incumbent transmission providers could not block new entrants from building transmission, promote transmission to serve public policy interests such as the development of renewable power, and tie cost allocation to regional transmission planning in a way that would assign costs to those who would benefit from the new facilities.

The senators' Electric Transmission Customer Protection Act, S. 400, would provide that "no rate or charge for or in connection with the transmission of electric energy ... shall be considered just and reasonable unless the rate or charge is based on an allocation of costs for new transmission facilities that is reasonably proportionate to measurable economic or reliability benefits projected, as determined by the commission, to accrue to the one or more persons that pay the rate or charge."

According to the sponsors, the proposed FERC rule would give the commission "sweeping authority to broadly spread the associated costs to customers outside of the area immediately serviced" by the new transmission lines.

According to a background document released with the legislative language, FERC "broadly defines benefits to include meeting public policy goals, which could result in consumers in one state or region being charged for transmission from which they receive no direct benefit." The sponsors pointed to language in the proposed rule, and a recently approved Midwest Independent Transmission System Operator tariff order, that would create a new category of transmission projects "that will be evaluated to determine if the projects support a public policy requirement, such as a renewable energy standard."

Corker called for "federal policies that promote viable domestic energy production and innovation in the fairest, most cost-effective manner possible." He said "governors and utilities from across the country have spoken out against FERC's attempt to shift transmission costs from states that benefit to those that don't."

Recent FERC decisions "could put Oregon ratepayers on the hook for the cost of electric transmission projects they can't really use," Wyden maintained, saying the bill would "send a message to FERC that I am prepared to step in to protect Oregon ratepayers from regulations that fly in the face of common sense."

The principle that cost burdens should be directly related to the benefits ratepayers receive from new transmission infrastructure "needs to be absolutely clear in FERC's regulations, and right now it isn't," he added.

In May 2009, Corker succeeded in offering a similar amendment to an energy bill that was approved by the Senate Energy and Natural Resources Committee. Murkowski is the ranking Republican on that committee and Corker and Burr are also members.

— Chris Newkumet

Proposed formula for frequency regulation compensation aims to give fairer treatment

The Federal Energy Regulatory Commission, aiming to compensate frequency regulation services more fairly, has proposed to require organized power markets to use a two-part payment for those services. It sought comments, however, on exactly how the payment would be determined and potential tariff issues.

Frequency regulation services generally refer to advanced technologies that provide ancillary services and follow the instant needs of a transmission dispatch signal more quickly, efficiently and accurately than some generation sources that take longer to ramp up and down.

"Frequency regulation is critical to maintaining grid reliability," FERC Chairman Jon Wellinghoff said. Minor deviations from the standard 60 Hertz grid frequency can affect devices that use electricity, and major deviations cause generation and transmission equipment to cut off from the grid, leading in the worst cases to cascading blackouts.

Today, frequency regulation is largely provided by generators, such as hydro, steam and combustion turbines that are specially equipped for this purpose, the proposed rule says (Docket No. RM11-7). But these services also can come from such emerging technologies as energy storage, electric vehicles, demand-side resources and possibly even residential water heaters, Wellinghoff said.

"The organized markets may not be capturing the value of this faster and more accurate service because currently, compensation to the providers is not typically based on performance," he explained.

FERC is concerned that frequency regulation compensation practices of regional transmission organizations may be resulting in rates that are unjust and unreasonable and unduly discriminatory or preferential, the notice of proposed rulemaking says. The scope of the rulemaking is limited to RTO markets.

The commission based much of its concerns on what RTO officials and frequency regulation providers said in a May 2010 technical conference and in comments filed later. "With regard to market designs for frequency regulation service, participants at the technical conference generally agreed that compensation for regulating resources ought to reflect the service they perform for the system operator," the NOPR says. "However, there was disagreement regarding whether current market designs accomplish this objective."

Nevertheless, FERC preliminarily "finds that slower, larger resources are being given a compensatory advantage for their size while faster, smaller resources do not similarly receive compensation for their ramping speed." Compensation should take into account the greater amount of service provided by faster-ramping resources, through more frequent provision of up and down frequency regulation, the commission suggests. This greater amount of frequency correction is not reflected in payments because the resource's generation and withdrawal contributions are often netted, making it look as if the resource provided less service than it did.

The proposed rule "is agnostic with respect to which technologies can take advantage of this pay-for-performance framework," Commissioner John Norris said. He also pointed out that the proposed rule does not address frequency response, which was the subject of a recently issued FERC study. The commission is currently taking comments on those study results.

Frequency response is the automatic, autonomous and rapid action of a turbine to change a generator's output or of a demand response resource to change consumption in response to changes in transmission frequency. Frequency regulation, in contrast, requires a dispatch signal from a grid operator.

Of the RTOs, only the Southwest Power Pool does not have a frequency regulation market to compensate these resources. Outside of organized wholesale markets, frequency regulation is served by the transmission provider on a cost-of-service basis through a rate schedule, with the transmission provider selecting the mix of resources it uses to perform this task.

Some RTOs, including PJM Interconnection, are discussing changes to their frequency regulation markets, Commissioner Philip Moeller said at FERC's open meeting Thursday. He asked staff how the proposed rule might interplay with those efforts.

"It's pretty much good timing," said Bob Hellrich-Dawson of the Office of Energy Policy and Innovation. The proposed rule will give PJM something concrete to look at in considering its own reforms.

FERC proposes to require a two-part payment for resources providing frequency regulation service to RTOs and ISOs. It also seek comments on exactly how providers should be compensated for their performance under this two-part payment so that these resources have incentive to invest in frequency regulation capability and participate in organized wholesale markets. "Properly designed, these markets will provide the efficient and least-cost mix of resources for regulation service," Wellinghoff said.

Rewarding resources providing frequency regulation for quickly responding to system needs "should in turn, spur innovation in new technologies that provide this quick response, promote efficiency" in the transmission system and result in lower energy costs to consumers, Norris said.

The first part of the compensation formula would be a capacity, or option, payment. While most RTOs and ISOs currently provide capacity payments for frequency regulation service, the proposed rule would refine existing practices by requiring that offers into a frequency regulation market include all opportunity costs, and that a uniform market clearing price be paid to all cleared resources.

FERC asked for comments on its proposal to require each regulating resource to be provided a uniform capacity payment that includes the supplier's opportunity costs. Typically, opportunity costs are the difference between what a resource could have made by providing a standard electricity product, but did not make because the resource was on stand-by to provide frequency regulation service.

The second portion of the payment would require that all resources that are dispatched to provide frequency regulation service be compensated for performance. That is, for each megawatt a unit is dispatched up or down, the absolute value of the movements would be summed. An RTO would make a calculation to determine compensation. FERC asked for comment on whether there are alternative payments for performance that would address concerns of undue discrimination.

Noting that the rules would not apply to entities outside of RTOs and ISOs, Norris suggested FERC take a separate look at how these resources are procured and compensated in non-organized markets.

Although he voted in favor of the proposed rule, Commissioner Marc Spitzer dissented in part out of concern that the existing record on frequency regulation services was not robust enough for the commission to propose a rule, he said in a statement attached to the proposal. "I am concerned that the limited participation [in the technical conference and follow-up comments] from entities other than the RTOs/ISOs and non-traditional technologies undermines the record on which to base a change to our regulations."

"I believe there is no basis to propose a single, one-size-fits-all approach for frequency regulation compensation," Spitzer said. "In fact, several commenters caution specifically against such an approach."

He is also concerned that the proposed rule could distract from, or otherwise delay, ongoing RTO efforts on the frequency regulation compensation issue. FERC should have had gathered more information and input through a notice of inquiry or advanced notice of a proposed rulemaking before moving forward with a specific proposal, Spitzer said.

— Esther Whieldon

FERC OKs rate incentives for muni groups' participation in CAPX2020 grid projects

So that two municipal utilities will receive returns on their transmission project investment comparable to those of investor-owned utilities, the Federal Energy Regulatory Commission has approved incentive rate treatment for them for their participation in a 345-kV power line proposed in Minnesota and South Dakota.

Central Minnesota Municipal Power Agency and Midwest Municipal Transmission Group initially committed to pay for about $13.2 million of the Brookings Project, a 240-mile, 345-kV line between Brookings County, South Dakota, and the Twin Cities in Minnesota, as well as a 10-mile, 230-kV line between two substations in Minnesota. The project's original price tag was $598 million; it is now estimated at $794 million

Now the muni groups have offered to invest as much as $35 million, to approximate more closely the load ratio share of their members, Central Minnesota spokeswoman Lori Frisk-Thompson said Thursday. She said the offer would be considered this week at a meeting of CapX2020, of which the Brookings Project is a part.

CapX2020 is a transmission expansion initiative by 11 Midwest utilities that are seeking to build five major lines for about $1.7 billion by 2020.

For the investments of Central Minnesota Municipal and Midwest Municipal, FERC approved full recovery of the costs of construction work in progress and of the facilities if they are abandoned or canceled for reasons beyond the developers' control. It also granted a hypothetical capital structure of 50% equity and 50% debt to be applied during the construction and the term of bond financing for the project.

The muni groups "face significant risks and challenges in developing and constructing their interest in the Brookings project ... and we find that they are eligible for the package of incentives that we are granting," FERC ruled. The commission explained that it has permitted municipals and cooperatives to use a hypothetical capital structure for ratemaking purposes when they have relied on non-equity financing for a project. Without it, there would be no meaningful return on investment once the construction period ends, FERC said (Docket No. EL08-32).

The municipalities did not seek to change the existing FERC-approved 12.38% rate of return on equity applicable to transmission owners in the Midwest Independent Transmission System Operator region.

By obtaining FERC's approval, the groups said, they are not waiving their status as nonjurisdictional to FERC. In its order, the commission explained that it has committed to entertaining, as much as it can, public power requests for incentive rates for transmission investments when the munis or other public power entities participate in new projects with FERC-jurisdictional entities.

Plus, FERC said, it can look at a nonjurisdictional entity's rates if necessary to determine that jurisdictional rates are just and reasonable. "Central Minnesota will derive its transmission revenue requirement using Midwest ISO's ... formula rates, and as a result, its revenue requirements will be subject to commission review to ensure that rates for service provided by Midwest ISO, a public utility, are just and reasonable," the commission said.

Commissioner John Norris dissented from the majority in the order, which said his statement would be issued later.

— Esther Whieldon

Court agrees FERC was wrong to OK plan for reactive power compensation in MISO

A federal appeals court has sided with generating companies that objected to the Federal Energy Regulatory Commission's approval of a reactive-power compensation rate schedule proposed by transmission owners in the Midwest Independent

Transmission System Operator.

Reactive power creates stable voltage so that power can flow across the grid.

Dynegy, FirstEnergy Solutions and Exelon had told the US Court of Appeals for the District of Columbia Circuit that FERC improperly relied on its policy on compensation for reactive power supply in approving the MISO rate schedule known as Schedule 2A (*Dynegy Midwest Generation, et al. v. FERC,* Docket No. 09-1306). A group of transmission owners in MISO had proposed the rate schedule.

But the generators told the court that the new compensation mechanism allows transmission providers to discriminate unduly against similarly situated generators within MISO by opting out of compensating generators in one zone but not in another.

In addition, they said, FERC did not address their arguments that the tariff change was unduly discriminatory and allowed preferential rates for generators.

The three-judge panel agreed, and vacated FERC's approval decision.

FERC "paid virtually no attention to petitioners' independent argument that its order allowed undue discrimination" in violation of Section 205 of the Federal Power Act, said the opinion written by Judge Stephen Williams and agreed to by Chief Judge David Sentelle and Judge Janice Brown.

The court went on to question whether FERC even understood the companies' discrimination complaint. The commission "insisted that so long as the proposed Schedule 2A requires transmission owners to treat affiliated and unaffiliated generators comparably, ... resulting zonal variations in compensation would not be unduly discriminatory," said the court.

"This completely disregards the core of petitioners' theory," the court said. Generators in MISO compete across zonal boundaries. "If transmission owners in one zone offer cost-based compensation for reactive power under [one rate schedule], while transmission owners in another zone invoke Schedule 2A and therefore withhold compensation for reactive power within the deadband, generators in the latter zone appear to be competitively disadvantaged."

The court also rejected FERC's claim that the incremental costs of reactive power within a deadband range is minimal. "There is ... no finding to that effect in this case, and no evidence in the case that would support such a finding," the opinion said.

— Esther Whieldon

FERC approves service agreement for line NU and NStar plan to build from Quebec

Northern Pass Transmission, which plans to build a 140-mile, 1,200-MW DC line designed primarily to bring hydropower from Quebec to the New England market, has won federal approval of

Kentucky Power seeks PSC permission to form state's first independent transmission company

Kentucky Power, an American Electric Power subsidiary, asked the Public Service Commission last week to approve its formation of an independent transmission company (Case No. 2011-00042).

If approved, it would be Kentucky's first transco, according to PSC spokesman Andrew Melnykovych.

The application by the Frankfort-based utility represents another step along the path of implementing a long-held strategy of Michael Morris, AEP president, chairman and CEO, to establish transcos in most of the 11 states where the Columbus, Ohio-based company operates (*EUW*, 8 March '10, 8). Morris says transcos "capitalize on capital markets by not burdening the operating companies with extensive capital needs" in constructing new transmission projects.

Indeed, that is the argument Kentucky Power is making to the PSC.

"The reason for creating a transco is so we can go out and get financing for those transmission projects at a rate that basically the investment community has told us they are more willing to invest in when it's a single entity," Ranie Wohnhas, Kentucky Power managing director, regulatory and finance, said.

In testimony filed with the commission, Wohnhas said a transco could devote all of its capital resources to the transmission development while Kentucky Power "would have to allocate its scarce resources among the various functions of a vertically integrated utility." By having a transco finance certain transmission investments that otherwise would be built by the utility, "[i]t will help alleviate some of the financial pressures" on Kentucky Power.

Kentucky Power, added Wohnhas, is facing "significant pressure to maintain its credit ratings while, on the other hand, its projected capital spending needs are significant across all areas of its utility business. If these significant projected capital spending needs were to be constructed and financed through Kentucky Power, the increased debt burden could adversely affect its financial condition and credit profile."

Over the past four years, Kentucky Power has spent the following amounts on transmission projects: $16 million in 2007, $26.5 million in 2008, $12.6 million in 2009, and $15 million in 2010. Those amounts accounted for up to 28.2% of the company's total annual capital expenditures, he said.

Wohnhas, who said Kentucky Power's 175,000 customers in eastern Kentucky would not be adversely affected by a transco, nevertheless expects several parties to intervene in the case, including the Kentucky Industrial Utility Consumers, a statewide trade group, and Attorney General Jack Conway.

KIUC attorney David Boehm confirmed his group does, in fact, intend to intervene, although it still is compiling information on the request and has not yet staked out a position.

Conway's office could not be reached for comment.

— Bob Matyi

its transmission service agreement and return-on-equity requests.

The company, a joint venture owned by subsidiaries of Northeast Utilities Service and NStar Electric, has a TSA with H.Q. Hydro Renewable Energy, a unit of Hydro-Quebec, under which Northern Pass will sell 1,200 MW of firm transmission service to the HQ unit. The TSA will also allow HQ to deliver power from New England to the US border for export to Quebec.

The Federal Energy Regulatory Commission approved the company's application for a 12.56% overall rate of return on equity for the project prior to its commercial operation. The figure consists of a base ROE of 10.4% plus ROE adders of 50 basis points for regional transmission organization membership and 166 basis points for investment in new transmission (Docket No. ER11-2377).

After commercial operation of the estimated $1.1 billion project begins, the approved ROE may still be 12.56% as requested, FERC said. It includes the 50 points for RTO participation and 92 basis points for investment in new transmission. The incentive adders would be on top of the base ROE under ISO New England's open-access tariff, which FERC notes is now 11.14%.

FERC approved the ROE proposals although it quarreled with Northern Pass' exclusion of some companies from the proxy group used to calculate the rate of return; the exclusions did not affect the result, the commission said.

FERC accepted the TSA for filing to be effective February 14. That effective date is "necessary to trigger various provisions of the TSA that commit the parties to move forward with the design, siting and construction of the NPT Line," Northern Pass had said in its December application.

Next up for the developers of the line, which would run from the Des Cantons substation in Quebec to Franklin, New Hampshire, is a series of five March scoping meetings, NU spokesman Al Lara said, adding that the first of these is scheduled for Pembroke, New Hampshire, March 14.

The line must also pass muster with ISO New England, which will look at the technical merits of the line and how it will affect the New England grid. It must also receive permits at the state and provincial level in the US and Canada, respectively. Lara said applications for the permits would be submitted over the next 12 months. Northern Pass has also applied for a presidential permit from the US Department of Energy to export power.

The project is to interconnect at the international border with a new transmission line to be owned and built in Quebec by Hydro-Quebec TransEnergie, the transmission division of Hydro-Quebec.

The line's in-service date remains 2015, Lara said, adding that the developers hope to start construction in late 2012 or early 2013.

— Paul Ciampoli

Tweaking final rule on RTO credit issue, FERC moves to trim default risk

The Federal Energy Regulatory Commission is lowering the cap on unsecured credit available to entities within a corporate family in order to decrease the financial risk that defaults pose to organized wholesale power markets.

While the original 2010 rulemaking (Docket No. RM10-13) adopting credit policies in organized markets set a $50 million limit for individual entities and an overall $100 million cap for a corporate family of entities in each market, FERC decided Thursday to revise that policy on rehearing and lowered the cap for corporate family of entities to $50 million.

In the markets of regional transmission organizations and independent system operators, participant defaults that are not supported by collateral typically are socialized among all other market participants.

Six California cities and Morgan Stanley had asked the commission to reconsider the $100 million cap for affiliated entities. Morgan Stanley said separate caps would encourage participants to reconfigure their corporate structures to be able to use the higher limit.

In agreeing with Morgan Stanley, FERC said "affiliated entities should not be able to impose a greater risk to the stability of organized wholesale markets than individual entities."

"The cumulative danger posed by a $100 million corporate family cap on the use of unsecured credit poses an unacceptable risk to the organized wholesale electric markets" as most participants either themselves or through subsidiaries participate in multiple markets.

FERC found persuasive the six cities' argument that there was a bigger danger to the market in allowing a $100 million cap. "Socializing such losses to other market participants could lead to even more significant market disruption than merely the default of a single entity," it said.

The order also denied petitions for rehearing of other aspects of the original rule.

FERC, however, extended the deadline for RTOs and ISOs to propose tariff revisions to protect against a default in the event a company challenges payment under a bankruptcy proceeding. The deadline is now September 30, rather than June 30.

Southern California Edison had requested an extension to allow each ISO and RTO adequate time to consider the three options FERC suggested in the credit reforms order and to evaluate alternatives that would provide a commensurate level of protection under a bankruptcy proceeding.

FERC's revisions to the credit rules will take effect 30 days after the *Federal Register* publishes the order.

— Esther Whieldon

FERC accepts SoCal Edison interconnection deals with solar plants; dismisses protests

Southern California Edison had two generator interconnection agreements with large solar power facilities conditionally approved by the Federal Energy Regulatory Commission last week.

In both cases, FERC dismissed protests by municipal utility interests related to concerns about SoCal Ed customers paying for the transmission upgrades.

In one case, SoCal Ed's connection agreement is with AV

Solar Ranch 1, a subsidiary of First Solar, for a 250-MW photovoltaic project in Kern County, California, where the output of the facility is committed to Pacific Gas and Electric. The other involves Palen Solar II, which is developing a 500-MW solar thermal generation facility being built in two phases, FERC said in the orders (Docket Nos. ER11-2411 and 2455).

For the Palen facility, the transmission system upgrades needed to support the full output of the facility cannot be completed until 2017, and Palen has agreed to finance about $6 million in interconnection facility costs, with the project's total transmission and distribution upgrade costs exceeding $127 million.

The M-S-R Public Power Agency, based in Modesto, protested SoCal Ed signing an interconnection agreement with both project developers, asserting that the utility is making all utility customers pay for upgrades with no benefit to them.

Regarding the Palen facility, SoCal Ed is buying the output and it sought certain incentives from FERC, including recovery of all prudently incurred upgrade costs that it would fund upfront if the project is abandoned because of circumstances beyond the utility's control.

FERC approved the interconnection agreement with Palen, subject to the outcome in the separate proceeding on incentives. The same condition is included in FERC's approval of the interconnection agreement for the planned AV Solar facility.

In addition, FERC said the California Independent System Operator's generator interconnection procedures have a process for determining whether facilities qualify as network upgrades, and FERC's review of the AV Solar project "indicates that the facilities in question are network upgrades."

— Tom Tiernan

ENVIRONMENT

New Hampshire closer to withdrawing from 10-state cap-and-trade program

Legislative observers say New Hampshire appears increasingly likely to withdraw from the nation's only mandatory program to cap-and-trade greenhouse gases following approval of the move by a legislative committee last week.

The Science, Technology and Energy Committee voted 13-5 to send H.B. 519 to the House of Representatives. Committee members voted along party lines, with Republicans in favor and Democrats against removing New Hampshire from the 10-state Regional Greenhouse Gas Initiative.

"It was not a shock to anyone," said Jim O'Brien, executive director of Conservation New Hampshire.

RGGI supporters are pessimistic about defeating the bill, which is expected to go before the House next week. Republicans hold a veto-proof supermajority in both branches. Governor John Lynch, a Democrat, opposes the bill and may not be able to sustain a veto.

Officials associated with RGGI declined to comment.

O'Brien said he has some "guarded" hope, however, that the Senate might consider RGGI reform over complete rejection of the program. Those reforms could include giving the state more oversight over how RGGI funds are spent.

The bill has support among climate change skeptics and political conservatives, but is opposed by several environmental groups and large companies that have received state funds for energy efficiency upgrades generated through RGGI allowance sales.

Kenneth Colburn, environmental policy director for New Hampshire-based yogurt maker Stonyfield Farm, said that New Hampshire will come out on the losing end economically should it withdraw from RGGI. As part of the New England Power Pool, the state will continue to pay an extra $5.6 million annually in regional energy clearing prices brought about because of RGGI, but not receive allowance revenue.

"The problem comes in that as a non-participant, New Hampshire would no longer be at the table when the RGGI spoils are divvied up," Colburn said.

Lynch said the state had spent $11.7 million on RGGI by the end of 2010, but accrued $28.2 million in allowance revenue.

RGGI states so far have channeled more than half of their allowance revenue into energy efficiency, about $391 million. The states structured their RGGI programs so that part of the money from allowance auctions would go into energy efficiency to reduce customer bills and offset RGGI costs.

Representative Andrew Manuse, a bill sponsor from Derry, said that RGGI repeal is necessary because the program has hurt the state's economy.

"Even if carbon dioxide emissions are a problem for the environment, and I'm not saying whether they are or aren't, the Regional Greenhouse Gas Initiative has not substantially impacted the reduction of emissions. Yet it has had a significant negative impact on economic growth," Manuse said.

In testimony last week, Manuse cited figures from Professor Gabriel Calzada at Juan Carlos University in Spain estimating that every green job created through a cap-and-trade program costs $774,000 and eliminated 2.2 other jobs because of high energy prices.

Manuse also alleged that if New Hampshire stopped producing CO_2 now, those emissions would be replaced in eight days by countries outside the US.

In an analysis of H.B. 519, Environment Northeast argued that Manuse's argument leads to a situation where a problem never will be fixed. RGGI states are the equivalent in size to some of the largest countries in the world in terms of economic output and emissions. "Until the developed world leads on reducing emissions, the developing countries will never follow," the organization said.

Environment Northeast also disputed the economic arguments against RGGI, saying that "other cap-and-trade programs for pollutants like lead and [sulfur dioxide] have been widely acknowledged as being cost effective and having demonstrated clear economic benefits."

The bill passed out of committee with some amendments, including a guarantee that utilities will be able to recover costs for any allowances they have purchased so far. The amended bill also retained a state board that oversees RGGI and other green energy funds.

In related business, Lynch did not use RGGI funds this year to help balance a state budget he released last week. The governor came under fire last year when he took 11% of the New Hampshire's RGGI revenue, about $3.1 million, for use in the state general fund.

— Lisa Wood

AWEA objects to wildlife protection guidance, which it says would be a blow to development

The US wind industry last week opposed draft guidance on wildlife protection recently issued by the Department of the Interior, saying it could lead to a delay in wind projects, require turbines to shut down at certain times and add costs to developing wind projects.

The American Wind Energy Association distributed a news release criticizing the guidelines the same day AWEA CEO Denise Bode and wind developers met with reporters in Washington to say that they would be seeking a "level playing field" from Congress this year.

Interior's Fish and Wildlife Service this month released for public comment "Voluntary, Land-Based Wind Energy Guidelines" and "Draft Eagle Conservation Plan Guidance." Bode said the wildlife guidance — which wildlife conservationists criticized for being voluntary — would have a chilling effect on wind development at a time when the country should be exploring the use of more renewable generation.

According to AWEA, the guidance could end up requiring operating projects to retroactively conduct post-construction wildlife studies for up to five years, require operational changes such as shutting down turbines at certain times and require analysis of wildlife-based sound impacts without any peer-reviewed scientific evidence that wind turbine noise could affect wildlife.

AWEA said that it supported a separate set of guidelines developed over more than two years in a "public, collaborative federal advisory committee process" that also included wildlife groups, but "unfortunately the guidance released last week deviates significantly from the consensus recommendations."

Wind industry executives were meeting with members of Congress last week. Bode said that with new faces in Congress, AWEA would be focused on education as it pushes for a federal clean energy standard and renewal of a federal tax credit for renewables.

"It always takes a while for a new Congress to settle out," Bode said. "There is a great opportunity while they are in this listening mode ... . We have an opportunity to capture them with the facts."

Bode lamented that AWEA must return to Congress to lobby for a tax credit that expires every year, while fossil-based energy sources enjoy long-running and ongoing subsidies. "The only thing we have is one tax credit," an exasperated Bode said.

— Jason Fordney

NUCLEAR

Some need more convincing about modular reactors, while others are pushing for them

Despite enthusiasm among nuclear reactor vendors and the Obama administration about the potential of small nuclear reactors, some utilities have yet to be convinced of their economic viability.

Bill Johnson, chairman, CEO and president of Progress Energy, said last week that the company is unlikely to build small nuclear reactors in the next two decades, even though some vendors hope to make such units commercially available by 2020.

It is "an intriguing thought" to build nuclear plants "on a small scale, plug-in and play, [and] modular" fashion, Johnson said, but he added that "the timetable for that looks more like the 2030s, just given the pace of development."

By then, he said most remaining coal plants will be large units, as Progress is retiring a third of its coal plants, mostly smaller ones, and replacing some of them with natural gas. Johnson spoke at a Platts conference on nuclear energy in Bethesda, Maryland.

"It's going to come down to cost," he said. If a 100-MW plant will need the same size security and operating staff as a 1,000-MW unit, he said, "that's going to make it difficult."

Duke Energy has proposed acquiring Progress in an all-stock deal. Johnson would be CEO of the combined company, which would be the largest utility in the US.

At the same conference, officials from the Department of Commerce and Department of Energy told the audience that the Obama administration sees big potential in small reactors to boost US competitiveness and re-energize the country's manufacturing base. The White House's budget proposal, unveiled Monday, has requested $97 million for DOE to accelerate commercial deployment of small reactor technologies.

In contrast to Progress's reservations about small-scale nuclear plants, Jack Bailey, vice president of Nuclear Generation Deployment at the Tennessee Valley Authority, said his company plans to be the first utility in the US to build a set of small reactors. TVA is studying the feasibility of beginning construction of up to six mPower modules — 125-MW reactors under development by Babcock & Wilcox — at its Clinch River site in 2020.

Bailey spoke at the same conference and said small nuclear units can potentially replace TVA's fossil fuel plants where the existing transmission lines and water use rights could accommodate the transition. Given that small reactors need less upfront capital to build, Bailey said, TVA could buy a certain number of units without federal loan guarantees. In comparison, he said, "it's hard to spend $10 to $14 billion at a time for new nuclear generation capacity" — the capital cost typically required to build a large nuclear power unit.

B&W has said it plans to submit an application for the Nuclear Regulatory Commission to certify its mPower design next year and is aiming to build the first unit by 2020. CEO Christofer Mowry, speaking at the Platts conference, said the modular design of mPower would enable the reactor to be built and assembled in a factory and transported by rail to the construction site. Such a concept, he said, would slash construction time and provide cost certainty.

Bailey said TVA is talking with DOE about powering the Oak Ridge National Laboratory with the mPower units.

DOE has to reduce its greenhouse gas emissions by 2020 to 28% below its 2008 level on all its facilities, including national laboratories, under an executive order President Barack Obama issued last year. Bailey said small reactors could help DOE meet its goal.

— Yanmei Xie

RENEWABLES

With Democrats vowing to fight against cuts, funding measure would slash DOE loan guarantees

The Department of Energy could be forced to rescind eight conditional loan guarantee offers totaling $3.2 billion and terminate the applications of dozens of other clean-energy projects if two provisions in the Republican-drafted continuing resolution become law, prompting the renewable energy industry and its allies on Capitol Hill to warn that thousands of jobs are at risk.

The CR, which the House was still considering at press time Friday, would slash $25 billion in funding for the DOE's loan guarantee program, but spare nuclear projects from those cuts. A separate provision in the CR would rescind unobligated funding from the American Recovery and Reinvestment Act, including about $10.8 billion in loan guarantee authority for innovative clean energy projects.

Senator Dianne Feinstein, a California Democrat, said those provisions would prohibit DOE from finalizing any of the loan guarantee applications it is currently reviewing. At stake would be 31 clean-energy projects investing a total of $24 billion in capital, which would result in 35,000 jobs, she said in a letter to her Senate colleagues.

"American industry has asked Congress to provide a predictable business environment," Feinstein said in her February 15 letter. "Yet the House CR would eliminate the DOE's loan guarantee program without warning and without provision for loan applicants who have negotiated with DOE in good faith for multiple years."

Without loan guarantees, these 31 projects would likely lose their outside investors and potentially go bankrupt, she said. The loan-guarantee program helps companies secure financing to build new nuclear power plants, wind farms, biorefineries and other projects.

"Cutting the DOE loan guarantee program, just as it is about to close on the financing of a large number of renewable energy projects and put 35,000 Americans to work in the clean energy economy, would be penny-wise and pound-foolish," Feinstein wrote.

House Republicans unveiled the loan guarantee cuts as part of their overall plan to slash $100 billion from President Barack Obama's fiscal 2011 funding request, saying that reining in federal spending would allow the economy to recover and generate jobs.

Democrats have said the cuts go too far and would actually harm the US' emergence from the recession. The CR would fund the federal government from March 4 through the end of fiscal 2011 on September 30. Democrats, who still control the Senate, have vowed to block some of the cuts, and President Barack Obama also has threatened to veto the CR if it passes both chambers.

The Obama administration, in its fiscal 2011 budget request, which was never approved by Congress, requested about $5 billion in additional renewable energy loan guarantee authority and $36 billion in nuclear loan guarantee authority.

To date, DOE has about $29 billion remaining in renewable energy loan guarantee authority, including Recovery Act funding, in addition to $8 billion remaining in fossil energy loan guarantee authority, $2 billion for front-end nuclear projects and $10.2 billion for nuclear power projects.

DOE confirmed that the CR's cuts would cause the agency to rescind all of its conditional loan guarantee offers, including one it issued last Thursday to SoloPower Inc. for a solar panel manufacturing facility in Oregon, as well as terminate all of the applications it is considering.

Energy Secretary Steven Chu, speaking to reporters after testifying before the House Energy and Commerce Committee on Wednesday, said the Republicans' proposed loan guarantee cuts would compromise "a lot of what we need to do in winning the future and getting things going."

DOE has touted the loan guarantee program as a means of unlocking capital investment for clean energy projects that has been sidelined due to the recession.

But House Energy and Commerce Committee Chairman Fred Upton, Republican-Michigan, said the loan guarantee program is of dubious value, noting that the first recipient, California-based solar panel manufacturer Solyndra, has closed one of its factories and laid off workers since it received its $535 million loan guarantee from DOE's portion of the stimulus package in September 2009 to expand a separate manufacturing facility.

Upton has requested documents from DOE that would explain its issuance of the loan guarantee to Solyndra, which has yet to turn a profit and last year abandoned plans for an

NEWS BRIEFS

Closing a financing deal months in the making, the **Department of Energy** last week finalized a $343 million loan guarantee to develop the One Nevada Transmission Line, which developers say would jumpstart solar and geothermal projects in Nevada. The 500-kV project, known as the ON Line, is set to carry about 600 MW 235 miles from Ely, Nevada, in the eastern part of the state to just north of Las Vegas. It is jointly owned by **Great Basin Transmission South** and **NV Energy**. This is DOE's first loan guarantee for a transmission project, and Energy Secretary Steven Chu said it would help integrate existing transmission systems in northern and southern Nevada, while improving grid reliability and efficiency. Michael Yackira, CEO of NV Energy, said construction of the line is "imminent." He spoke of the line's significance in promoting renewable energy projects. "With the enormous amount of geothermal we have in the northern part of the state and solar in the southern part that has yet to be developed, ON Line will make this development a reality," Yackira said.

... A federal court tossed out the **New York Regional Interconnection**'s lawsuit asserting that the **Federal Energy Regulatory Commission** should not have approved the **New York Independent System Operator**'s transmission planning process. NYRI lacks standing to bring the case, and it could not prove injury, said the **US Court of Appeals for the District of Columbia Circuit**. NYRI had objected to FERC's approval of the ISO's process. According to NYRI, the process is unjust in requiring that 80% of entities identified as benefitting from an economic transmission project vote in favor of it in order for the project to be eligible to recover costs from market participants. NYRI had proposed a $2 billion, 190-mile transmission project but pulled it from state Public Service Commission proceedings, saying that the supermajority voting provision allows incumbent utilities to vote down a competing project, and that FERC should have considered antitrust and anticompetitive policy implications in its orders. In the court's view, NYRI presented an "alleged injury" that "rests upon a hypothetical chain of events" — not actual harm (Case No. 09-1309).

... Two trade groups from opposite sides of the opinion spectrum on some important power market issues welcomed the House of Representatives **Energy and Commerce Committee**'s new oversight plan, which includes a review of **Federal Energy Regulatory Commission** activities. The **American Public Power Association**, which has been critical of FERC's oversight of organized power markets and independent system operators, said it appreciates the committee's intent to address wholesale power market competitiveness. "Although frequently referred to as 'competitive,' these markets bear no resemblance to true competition and as a result, have produced high and volatile prices, with negative implications for the business and manufacturing communities," APPA said in a statement. A spokesman for the **Electric Power Supply Association**, which generally supports organized wholesale power markets, said the group welcomes the House committee's planned oversight. EPSA looks forward to the committee's continued involvement in ensuring that there is well-functioning competition in the wholesale market, said Dan Dolan, vice president for policy research and communication.

... Public Service Electric & Gas asked the **Federal Energy Regulatory Commission** to release it from the obligation to buy power from qualifying facilities larger than 20 MW. The utility told FERC February 11 that it meets the conditions to be released from the purchase obligation in the Public Utility Regulatory Policies Act. Under FERC's PURPA regulations, where QFs larger than 20 MW have access to competitive markets like **PJM Interconnection**, a utility can be relieved of the obligation to buy from them. PSE&G is in PJM. The utility said it was not asking to be released from current QF contracts, but from signing new ones (Docket No. QM11-1). The filing identifies 10 QFs, including cogenerators and waste-to-energy plants. A PSE&G spokesman said that no current situation had led to the request, the option to make such a filing has been available since 2007, and other utilities in PJM have received FERC approval for similar requests. Melissa Lohnes, spokeswoman for one of the QFs, **Wheelabrator Falls**, a 48-MW waste-to-energy plant in Morrisville, Pennsylvania, said last week the PSE&G request "is a normal business practice in a deregulated market, and this will not impact our business as a result."

... American Electric Power said it would receive $4 million from an Australian organization to advance installation of the first US commercial-scale CO2 capture and storage system, under development at AEP's Mountaineer coal plant in New Haven, West Virginia. The **Global CCS Institute**, based in Canberra, Australia, is providing the funds to support the initial engineering and characterization of the system, which AEP expects to capture 1.5 million metric tons of CO2 per year. It will be treated, compressed and permanently stored in geologic formations about 1.5 miles underground, AEP said. Commercial operation is projected for 2015. The **Department of Energy** is funding up to $334 million, about half the cost of the CCS project. AEP said it is talking with other potential international partners.

initial public stock offering. Solyndra has said its financial woes will not cause it to default on its financing.

"The unfortunate reality is that the Energy Department's stimulus loan guarantee program highlights many of the systemic flaws associated with the stimulus," Upton said in a statement. "In the mad dash to spend hundreds of billions of dollars, projects were rushed and the highly-touted benefits from ribbon cuttings were not realized. The days of 'spend now, ask questions later' are over."

— Herman Wang

Texas to take up two bills in biennial session promoting solar, biomass, geothermal development

The Texas Legislature's consideration of electricity-related bills this biennial session will focus on two proposals: one would require the development of 1,500 MW of "non-wind," utility-scale renewable capacity by 2020, and another would provide incentives for developing distribution-scale solar capacity, legislative sources said last week.

S.B. 330, introduced earlier this month by Senator Kirk

Watson, an Austin Democrat from, would require that at least 100 MW of solar, biomass-fired, geothermal and other non-wind renewables be online by 2012. The mandate would rise to 200 MW in 2013, 350 MW in 2014, 500 MW in 2015, 750 MW in 2016, 900 MW in 2017, 1,000 MW in 2018, 1,250 MW in 2019, and 1,500 MW in 2020.

Watson's bill is an updated but nearly identical version of a measure he introduced in 2009 that was overwhelmingly approved by the Senate but died with many other measures during a legislative logjam caused by a controversial voter-identification bill, Watson said.

S.B. 330 and its companion bill in the state House of Representatives, H.B. 774, are "good for cities, which will benefit from cleaner air, and good for rural areas, which will benefit from the economic development" that will come with new, non-wind renewable projects, said Damien Brockmann, legislative director to Representative Rafael Anchia, the Dallas Democrat who introduced an identical bill in the House.

Meanwhile, Senator Troy Fraser, a Horseshoe Bay Republican and chairman of the Senate Natural Resources Committee, introduced a slightly amended version of a "distributed solar generation incentive" bill that, like the 2009 version of Watson's non-wind renewables bill, was approved by the Senate but died during the logjam that ended that session.

S.B. 492 would direct the Public Utility Commission to establish a program under which utilities would collect monthly "non-bypassable fees" from retail customers that would be used to provide financing incentives to customers who install solar photovoltaic panels.

Fraser's bill, which does not yet have a House companion, also would have the PUC establish appropriate rebate levels to be paid to those customers. The bill suggests, but does not require, that the rebates be set initially at $2,400/kW of installed capacity at residential locations, $1,500/kW at commercial sites and $1,000/kW at industrial sites.

The only significant change to the distributed solar generation incentive bill this session is the inclusion of a net-metering provision, said Janice McCoy, Fraser's chief of staff. In the Electric Reliability Council of Texas, which is open to retail competition, customers would be paid what the bill calls a "fair market" price for their surplus solar power using a methodology to be based on the market clearing price.

Until the PUC establishes that methodology, the bill says, customers would be paid at least 5 cents/kWh for surplus solar power and at least 4 cents/kWh for surplus power from other non-wind renewable sources.

In the rest of Texas, which is not open to retail competition, customers would be paid an amount "greater than or equal to" the avoided cost of the utility or electric cooperative. But co-ops would have to pay a minimum of 4.5 cents/kWh for surplus solar.

"We think both bills would work great side-by-side," said Brockmann, Anchia's legislative director. He believes that both measures are likely to advance through committees to the full Senate by the middle of next month.

— Housley Carr

Ontario blocks offshore wind farms indefinitely, calling for research on fresh water projects

Ontario has declared a moratorium on offshore wind development, placing a region once considered an industry leader in North America now behind the pack in building an offshore wind industry.

The Ministry of Environment said it would not allow installation of wind turbines on the Ontario side of the Great Lakes until further scientific research is conducted on their operation in fresh water.

The decision follows protests about potential noise and environmental harm in Lake Ontario from wind farm opponents.

"Offshore wind on freshwater lakes is a recent concept that requires a cautious approach until the science of environmental impact is clear. In contrast, the science concerning land-based wind is extensive," said John Wilkinson, Ontario Minister of the Environment.

So far, the world has but one fresh water offshore wind farm, a 30-MW pilot project built last year in Sweden's Lake Vanern. Fresh water projects have been proposed on both the US and Canadian sides of the Great Lakes.

Ontario also would stop accepting applications for its offshore wind feed-in tariff, which is C$0.19 cents/kWh. Because of the feed-in tariff, Ontario was often cited by renewable energy developers as a hospitable climate for offshore wind, in some ways better than the US where there is no national feed-in tariff.

Jim Lanard, president of the Washington-based Offshore Wind Development Coalition, said he saw no chill on the US market as a result of the Ontario decision. He described the US offshore wind market as "solid" and garnering increasing interest from international developers. "There is very significant pent up interest. We see it at conferences up and down the East Coast where hundreds of people are showing up to learn about the industry."

He added that for offshore wind to be successful, governments need to "identify a process that is transparent and lets everybody know how to proceed. The US has done that at the federal and state level. Ontario, in its enthusiasm, may have gotten a little ahead of itself."

Ontario's provincial government says it does not know how long the moratorium would last. The Ministry of Environment has yet to create necessary offshore wind rules, such as how far turbines must be set back from shore. The ministry does not intend to create the rules until it has more facts in hand about fresh water offshore wind, according to spokeswoman Kate Jordan.

Ontario intends to carefully watch the Swedish pilot project as well as a 20-MW pilot project planned for the Ohio side of Lake Erie. The province would conduct its own studies on offshore wind, as well as collaborate with US states and the Department of Energy, Jordan said.

One offshore wind farm already has won a feed-in tariff contract from Ontario's government, but its fate is uncertain. The 300-MW Wolfe Island Shoals Wind Farm, proposed near Marysville in Lake Ontario, won the contract in April.

"We are aware of the Ontario government's announcement regarding offshore wind projects, and are examining all of our options," said Randi Rahamim, spokeswoman for the developer, Windstream Energy, a Canadian company that has been pursuing the project since 1993.

Anne Smith, spokeswoman for the Ontario Power Authority, said that authority officials plan to meet with Windstream Energy to discuss what the moratorium means to the project's contract. The feed-in tariff agreement requires the project be built within four years.

In addition to the Windstream Energy project, three offshore wind farms totaling 30 MW have completed applications for feed-in tariffs, and another 30 MW of offshore wind is in the process of applying, Smith said.

Several other offshore wind farms also are being planned in Ontario, but have not yet applied for feed-in tariffs. These include Trillium Power's first offshore project, the 420-MW Trillium Power Wind 1, planned off the northeastern shore of Lake Ontario.

— Lisa Wood

Montana legislation would give utilities relief on renewable portfolio standard compliance

A bill proposed in the Montana Senate would give NorthWestern Energy a temporary "out" in complying with the state's renewable portfolio standard in 2015 if its current plans fall through.

The legislation, S.B. 220, by Republican Senator Edward Walker, would give utilities a waiver of three years or more if they cannot procure a renewable energy resource or renewable energy credits at a "reasonable price" of no more than 5% above the "retail electricity supply rate of the public utility or competitive electricity supplier," according to the bill. It was introduced by Walker at NorthWestern's request.

The bill would provide NorthWestern Energy a safety net if the 48 MW of wind power it is currently developing falls through. That 48 MW is expected to bring NorthWestern into compliance with Montana's RPS mandate that requires 15% of a utility's total production to be from renewable resources by 2015.

Utilities that do not meet their RPS mandates are fined $10/MWh, which they cannot recover in rates.

"If something happens to those projects, we're in a big world of hurt," said NorthWestern lobbyist John Fitzpatrick during the bill's first hearing in front of the Montana Senate Energy and Telecommunications Committee Tuesday. "If we have to go out and do this from scratch, it's going to be several years," before they will be able to meet the state's RPS requirements.

Fitzpatrick detailed for the committee how NorthWestern ended up with only two viable renewable projects after issuing a broad request for proposals in 2009 for any small-scale renewable project. He said the company received 41 responses, only half of which met the requirements. Prices ranged from $54/MWh to $156/MWh, with the average price of $80.14 — most of them higher than the state's qualifying facility rate of $69.21/MWh. NorthWestern selected three projects, one of which had to drop out because of siting issues.

Fitzpatrick said the company also has investigated extensively developing biomass, but that after more than six months of negotiations and crunching numbers, the best price the utility could get was about $101/MWh.

"The major problem in seeking compliance is the cost of new renewables," Fitzpatrick said. "You have to rationalize that against the market price of power."

Montana-Dakota Utilities also spoke in favor of the bill. John Alke, a lobbyist for MDU, said that the company did not have a problem acquiring renewable resources, but it is worried about the burden such resources will place on customers. MDU has built wind farms in North Dakota and Montana. The North Dakota Public Service Commission is considering denying MDU the right to allocate the costs of its wind farms to North Dakota customers because it has no state RPS. If the PSC follows through, the entire cost of the wind farms — an extra $5 million a year — would fall on Montana customers.

Alke proposed an amendment to the bill that would give utilities a long-term waiver to meeting the RPS if the utility can show that acquisition of renewable resources would have an adverse impact on customer rates.

The bill was even supported by wind developer Gaelectric, which is looking to develop thousands of megawatts of wind power in Montana. Van Jamison, vice president of Gaelectric North America, said that the bill would resolve a long-standing Montana debate over reasonable price caps for renewables in the state.

Jamison also said that he had no doubt that the utilities would be able to acquire renewable resources under the proposed price cap, especially if bills pending in the Montana Legislature to allow hydroelectric upgrades to count toward the RPS pass.

"I don't foresee how any diligent utility could fail to find the renewable resources it might need to comply with the RPS," he said. "Wind energy is cost competitive and can compete."

Jamison said that NorthWestern's Judith Creek wind farm is supplying power at $41.60/MWh, compared with a contract NorthWestern has with PPL Montana for purchased power at $49.40/MWh.

The bill is not the first heard by the Montana Legislature that takes aim at the state's RPS. Another, H.B. 244, by Representative Derek Skees, a Republican and member of the tea party, would have repealed the state's RPS. Skees' bill was tabled in committee after the committee's Democrats were joined by four Republican members in opposing it.

Senator Jason Priest, a Republican, has said he plans to introduce another bill that would likely place a sunset on the RPS in 2015.

— Pam Radtke Russell

FEDERAL POLICY

Collaborate, collaborate: Regulatory group heads agree it is only way to meet challenges

Tackling the electricity challenges ahead in the areas of demand response, integration of renewables and installing a smart grid — all while maintaining reliability and cybersecurity — will take a joint effort of states and the Federal Energy Regulatory Commission, a state utility regulator and FERC Chairman Jon Wellinghoff said February 16.

Also last week, a panel of grid security experts discussed solutions for protecting the nation's electricity infrastructure.

Collaboration among states and FERC "probably isn't optional anymore," said Garry Brown, chairman of the New York State Public Service Commission and head of the National Association of Regulatory Utility Commissioners' electricity committee.

"Collaboration doesn't always mean agreeing," Brown said at the National Electricity Forum in Washington sponsored by the DOE and NARUC. Rather, "it is an understanding of where people's motives are."

Brown expects that states and FERC will continue to disagree on how to address transmission construction, incentive rate treatment for power lines and cost allocation. But he maintained that both sides must keep an open dialogue if any solutions are to be found.

"Collaboration and cooperation are vital," Wellinghoff said on the panel with Brown. Depending on whether states and FERC work together, the smart grid may be a train wreck or it will take the nation to new heights, Wellinghoff said. "Collaboration is the only way it will work."

As for demand response and cost allocation, "FERC does not want to impose a single rule on everybody." It wants to "show people the way to ... the most efficient rule, the most efficient practice." That is why FERC called in the heads of regional transmission organizations to talk at a commission meeting recently about their best practices "and how those can be shared across regions," he said.

There are obvious areas where federal leadership is needed, Brown said. One is in creating smart grid rules and standards. When it comes to rules on privacy, interoperability and cybersecurity with a smart grid, "we can't invent those 51 times" he said of state and FERC standards-setting efforts. "It doesn't make any sense."

Wellinghoff declined to comment on how the commission is going to handle development of smart grid standards. He noted that the commission recently posted a request for supplemental comments on what to do next and said he would wait for those comments before coming to any conclusion.

He said FERC wanted more comment from industry on "how much rulemaking do they want to see FERC doing. What rulemaking could we do to help them? And what rulemaking would not help them?"

The grid is "really not ready yet for plug-in vehicles on a large scale," Brown said. "I think it will happen slowly enough that we can get ready, but right now there's nothing preventing somebody from coming home and there's no incentives for them not to go home at 5 o'clock ... and plug the car into the wall," even though the price of electricity is high and the grid is at its peak use.

The electric car has "this tremendous potential to be a load-evener, and to take advantage of renewable resources at night," Brown said. Yet it also has a "tremendous potential to cause new system peak problems if we get it wrong."

Some of these challenges can be addressed through technology, he continued. But states must act quickly to get the rules in place to allow for large-scale deployment.

State regulators have learned from experience that it does not work to force the smart grid down consumers' throats, Brown said. He described "the way we're going about the smart grid as a breech birth — the meters came out first. And it was the wrong way to go."

"It's going to be the entrepreneurs that drive the consumers [to want the smart grid] rather than the regulators," Brown said. It will happen when "really neat stuff is being developed" and consumers buy and use those products and demand more opportunities to use them to reduce their electricity costs, he said. The kind of service they will want must come through the smart grid and the two-way flow of electricity information it provides.

Using the iPhone as an example, Wellinghoff said the device is much more than a phone. It "does so many other things and is such a multi-tasking, multi-use device." Consumers will develop a similar perspective about some devices when they begin to be associated with the grid, he said.

One such item will be the electric vehicle, Wellinghoff suggested. "The electric vehicle is not going to be just an electric vehicle anymore. It's also going to be a grid device. It's going to provide services back to the grid and it's going to get paid to do it."

"When consumers start to figure that out [they] are going to say: 'Regulator you need to set that up and make it work so I can take advantage of that'."

The job of FERC and states is to set the regulatory infrastructure to enable entrepreneurs to make the business case to create devices that help consumers get involved in the grid, Wellinghoff said.

There are many things an iPhone can do, Brown agreed. Yet "my utilities have to drive around in a truck to find out where the electricity is out. I mean, how 20th century can you be?"

— Esther Whieldon

Seeking balance on hydropower fees, FERC solicits comments following court order

Responding to a court decision that threw out the Federal Energy Regulatory Commission's fee schedule of annual charges for owners of hydropower facilities, the commission on Thursday issued a notice of inquiry for how it should calculate rental rates for the use of government land by hydropower project owners.

The notice seeks suggestions on how to create a practical formula that applies uniformly to all hydropower facility owners, that does not impose exorbitant costs on FERC and reflects accurate land values, the commission said.

The NOI follows a January 4 ruling from the US Court of Appeals for the District of Columbia Circuit, which vacated the fee schedule FERC had been using to collect annual rental fees under its regulations.

The history of annual fees paid by hydro project owners includes individual assessments that became too burdensome — a national average per acre that resulted in a Department of Energy inspector general finding in 1985 that such a methodology undercollected fees based on outdated land values.

Since 1987, FERC had been using the US Forest Service's rental fee schedule to set the commission's annual charges for hydro projects on federal land. When the Forest Service annually updated the fee schedule, FERC likewise updated its charges, the court said in its ruling.

But in 2008, the Forest Service began using a "significantly different methodology" to assess the value of rentals than the one FERC had reviewed and endorsed in its regulation. FERC used the revised schedule, and in February 2009 issued a fee update schedule that resulted in substantially higher charges for many hydro project licensees, the commission related in its order (Docket No. RM11-6).

A group of municipal and private entities that own hydropower facilities challenged FERC's finding, asserting that it amounted to a rulemaking that was improperly issued without seeking comments. The court agreed, and said that under the Administrative Procedures Act, FERC must seek comment on the methodology it uses to calculate annual charges because the Forest Service changed its methodology.

"We begin that process here," FERC said in the order. It is seeking suggestions for creating a "practical methodology for assessing annual charges for the use of government lands that will result in reasonably accurate land valuations."

Among the major objectives FERC will consider are that any methodology should be uniformly applicable to all project licensees, not subject to review on a case-by-case basis, and that it should not result in increasing the price to consumers as a result. In addition, a methodology should reflect reasonably accurate land valuations, and be able to allow FERC collection in a "routine, ministerial process" that does not impose a heavy burden on FERC staff.

The comment deadline on the notice of inquiry is 60 days after its publication in the *Federal Register*.

— Tom Tiernan

RATES & REGULATION

Indiana Republicans key to approval of bill giving utilities more certainty on cost recovery

Flexing their majority party muscles, Indiana Senate Republicans are expected to give final approval to legislation providing more cost recovery assurances to electric utilities, and perhaps reviving nuclear power.

S.B. 251, on a party line 37-13 vote on February 17, won second reading approval in the Senate. Opponents concede the bill is almost certain to pass the Senate, then head to the House of Representatives which the GOP also controls, albeit by a slimmer margin.

Senators approved an amendment that, in the words of Kerwin Olson, program director for Citizens Action Coalition, an Indianapolis-based environmental and consumer advocacy group, "adds a little more certainty to utility cost recovery ... it gave a little more clarity to the [Utility Regulatory Commission] that they have to approve these things."

CAC contends the bill would force the public to pay for "exorbitantly expensive and highly speculative" nuclear and coal gasification plants. "As we have stated many times over the last four years, the only way utility companies can build coal and nuclear plants is by shifting all design, construction and operating risks to the ratepayer," said Grant Smith, CAC's executive director. "Ratepayers will be mandated to assume all of the risk, while monopoly utility companies walk away with all the profit."

Observers say the legislation could rekindle utility interest in nuclear power. The state's last brush with a nuclear project, more than a quarter-century ago, did not go well. In 1984, Public Service Indiana, forerunner of Duke Energy Indiana, abandoned its Marble Hill nuclear project at Madison which was suffering from several billion dollars in cost overruns.

PSI eventually was allowed to recoup most of its investment in Marble Hill and the partially completed plant was dismantled.

Among other things, S.B. 251 would extend the state's construction work in progress, or CWIP, law to nuclear power plants.

State Senator Beverly Gard, a Republican and co-author of the bill, says the legislation is needed to provide customers with a reliable, long-term source of power.

The Indiana electric industry supports the bill, in particular American Electric Power and its Indiana Michigan Power subsidiary. David Mayne, an I&M spokesman, said the legislation would facilitate the utility's plans for upgrades at the 2,100-MW

Donald C. Cook nuclear plant at Bridgman, Michigan. The Nuclear Regulatory Commission has extended licenses until 2034 and 2037, respectively, for Cook's two units.

One of the reasons the CAC is fighting the bill, Olson said, is because CWIP would apply to nuclear plants even if they are not in the state. As long as a utility owns at least 49% of a nuclear plant that serves some Indiana customers, it would be eligible for CWIP under the bill. Some of Cook's power supplies I&M customers in northern Indiana.

Controversial utility bill could split powerful father-daughter political duo in Illinois

A highly contentious utility infrastructure bill backed by Commonwealth Edison could split the powerful father-daughter duo of House Speaker Michael Madigan and Attorney General Lisa Madigan in Illinois.

The Madigans, both Democrats, do not see eye-to-eye on everything. But H.B. 14 Amendment 1, introduced in the General Assembly earlier this month, is shaping up as a high-profile example of their occasional differences of opinion (*EUW*, 14 Feb, 6).

Under the legislation, utilities could pursue automatic annual rate increases if they meet certain criteria for investing in infrastructure improvements, including smart grid and the transmission grid. Chicago-based ComEd, the state's largest electric utility with more than 4 million customers and an Exelon subsidiary, says it is prepared to spend an incremental $2.6 billion on the delivery side of its business over the next decade. But first, it wants more assurances it will be able to recoup its investment along with a favorable rate of return.

Lisa Madigan believes the bill "will seriously harm consumers," Robyn Ziegler, her press secretary, said last week. As the measure winds its way through the Legislature, the attorney general at some point is expected to testify in opposition to it.

Michael Madigan, a Chicagoan widely regarded as one of the most influential political figures in the state, is "supportive of the concept" of the bill, according to Steve Brown, the Speaker's top aide. While Brown would not say his boss definitely will endorse the bill, "[h]e feels the ICC has not done a good job in dealing with infrastructure kinds of questions ... it obviously will be a bill that will be under consideration during the session." He was referring to the Illinois Commerce Commission, which has not commented publicly on the bill.

If enacted into law, the legislation could mean automatic rate increases for all electric and gas utilities, the Citizens Utility Board is warning. The consumer agency, created by the Legislature more than a quarter-century ago, says it is willing to work with ComEd to add consumer protections to the bill.

Under the existing regulatory regime, system improvements by utilities must be approved by the ICC. The legislation largely would break with that tradition by allowing electric and natural gas utilities to automatically alter their rates to recoup their costs.

— Bob Matyi

And while Olson believes the main impetus for S.B. 251 is the planned Cook upgrade, he suspects it could make Indiana a more favorable destination for new nuclear plants perhaps by Duke, although the company has nothing allocated for that in its capital spending plan.

Chairman James Rogers has said Duke is thinking of building a nuclear plant in Ohio. But several utilities complain Ohio's 2008 restructuring law makes the state's regulatory climate unfavorable for investing in new generation.

If S.B. 251 becomes law, "It could benefit Duke," Olson said. The bill "is a utility wish list of the highest order, so to speak."

— Bob Matyi

MARKETS

FirstEnergy competitive supplier triples customers, as company cuts focus on POLR business

Competitive supplier FirstEnergy Solutions is growing by leaps and bounds as parent company FirstEnergy places less emphasis on its traditional provider of last resort business.

Unlike its Ohio utility counterparts, FirstEnergy's business strategy appears to be predicated largely on growing its competitive business. FES now serves 1.5 million retail customers, "effectively tripling our competitive customer base year over year," Mark Clark, FirstEnergy executive vice president and CFO, told analysts during the February 16 earnings conference call. Currently, FES operates in six states: Ohio, Pennsylvania, Illinois, Michigan, Maryland and New Jersey.

FirstEnergy executives were cagey about precisely where that growth is occurring. "In general, western Pennsylvania and the PJM territories we're focused on ... the utility territories reachable with our generation," William Byrd, FirstEnergy vice president of corporate risk and chief risk officer, said in response to a question from Paul Patterson of Glenrock Associates.

"We're active in all of those markets," chimed in Anthony Alexander, president and CEO. While he said it is not appropriate to publicly discuss the company's strategy, "the game plan in each market that has been laid out has been successfully implemented."

Byrd said it "would be safe to expect" that FirstEnergy is aiming to decrease its provider of last resort business over time. "Our strategy is to increase selling to competitive customers" and reduce POLR sales in Ohio, he noted.

Alexander said the company "continues to expand direct sales efforts in other states, including Illinois and Michigan. We doubled our sales outside of Ohio in 2010. I'm very pleased with our retail sales efforts ... we're growing the business."

Steve Fleishman of Bank of America asked Alexander about Todd Snitchler, the newly appointed chairman of the five-member Ohio Public Utilities Commission. Snitchler, a 40-year-old Republican, must resign from his job as a state representative before joining the PUC.

Alexander gave high marks to Snitchler, who succeeds veteran

Chairman Alan Schriber, who retired at the end of last year after a dozen years in the post. "Todd's a solid individual and understands the process pretty well from a legislative standpoint," Alexander said. "He's clearly a good choice for the role ... we should look forward to having solid regulation in the state of Ohio."

Alexander also said:

- FirstEnergy remains on track to complete its $4.3 billion acquisition of Allegheny Energy by the end of March. It needs only one more regulatory approval — from the Pennsylvania Public Utility Commission — and hopes to get it before the end of February.
- A "binding purchase agreement" with American Municipal Power for the sale of FirstEnergy's 707-MW Fremont Energy Center natural gas-fired plant in Ohio could come in March, Alexander added. The two parties recently signed a non-binding memorandum of understanding, although details were not disclosed (*EUW*, 14 Feb, 13).

Clark said FirstEnergy still intends to sell its co-owned Signal Peak underground coal mine in Montana later this year even though the mine's value "continues to increase." FirstEnergy and Boich Group, an Ohio company, acquired the mine two years ago and have invested more than $400 million in the operation. At full output, Signal Peak is expected to produce up to 12.5 million tons of coal annually, and FirstEnergy has a 15-year contract to buy up to 10 million tons a year.

Nevertheless, FirstEnergy still considers the mine a "non-core" asset.

— Bob Matyi

FERC asks for input about how to handle locational exchanges; Puget has asked

The Federal Energy Regulatory Commission is asking for comment on how to treat locational power exchanges and how they affect competition and transmission service.

FERC released a notice of inquiry last week in a proceeding flowing from Puget Sound Energy's June request for a determination that locational exchanges are wholesale sales, not transmission transactions subject to an open-access transmission tariff.

The treatment of locational exchanges — a simultaneous pair of purchase and sale transactions involving the same quantity of power and the same parties but at two different locations and at two different prices — "raises significant policy issues for market participants and therefore requires a broader inquiry," FERC said in a news release (Docket No. RM11-9).

FERC said it is asking broadly about the characteristics of the transactions "to understand how market participants use and benefit from them, as well as how the transactions affect the electric power system."

The commission said it also wanted to know whether the transactions affect congestion, and whether locational exchanges offer opportunities for transmission providers and their affiliates to discriminate against or between unaffiliated transmission service customers. FERC said it also was seeking information as to whether a party with network transmission rights could use the transactions to circumvent FERC's open-access transmission principles.

FERC also is asking whether the transactions allow some parties to obtain the functional equivalent of transmission service on more favorable terms or rates than those available to other parties, whether existing price reporting procedures ensure appropriate reporting of these transactions and whether these transactions affect transmission system reliability.

— Jason Fordney

COMPANY NEWS

New Orleans takes Entergy-unit withdrawals to court, challenges FERC's approval of them

The City Council of New Orleans has asked a federal appeals court to review the Federal Energy Regulatory Commission's ruling that two Entergy units may leave the Entergy system agreement without any fees or continuing obligations to the four other affiliates.

The city is concerned that Entergy New Orleans ratepayers might pay millions of dollars more each year for power once Entergy Arkansas and Entergy Mississippi exit the system agreement in 2013 and 2015, respectively, the city said when it asked FERC to reconsider its 2009 decision (Docket No. ER09-636). The commission denied rehearing February 1.

New Orleans on February 14 asked the DC Circuit Court of Appeals to review the case (*Council of the City of New Orleans v FERC*, 11-1043).

The Entergy system agreement is a FERC-approved rate schedule that allocates system production costs among the six Entergy units, which also include Texas, Gulf States Louisiana and Louisiana.

Under the agreement, the Entergy holding company that makes decisions about where generation is built has installed many of the lowest-cost units in the Entergy Arkansas region. The concept was that all Entergy affiliates would benefit from the units no matter the location of the new generation because there was a system agreement to share the overall costs.

Due to a production cost equalization bandwidth established by FERC in 2005, Entergy Arkansas has paid hundreds of millions of dollars to the other units to rebalance the generation production costs among the affiliates. This led Entergy Arkansas to give notice it would withdraw. Two years later the Mississippi unit announced it would pull out.

The agreement has a clause allowing individual operating companies to withdraw from the arrangement with 96 months' notice.

As a result of the withdrawals, the remaining four companies will remain in the collective system agreement, Entergy Arkansas and Entergy Mississippi will operate separately and the Southwest Power Pool will oversee all of the utilities' grids as their independent coordinator of transmission. This proposal is

Duke Energy Carolinas going viral with energy efficiency

Duke Energy Carolinas secured North Carolina regulatory approval for a novel energy efficiency pilot program that will use a variety of means — including social media like Facebook and Twitter — to encourage prudent electricity use within millions of square feet of downtown Charlotte office space.

The Smart Energy Now program, which will also include public displays showing real-time energy use, is a key element of the "Envision: Charlotte" plan unveiled by Duke Chairman and CEO Jim Rogers, Cisco Systems Chairman and CEO John Chambers, and city and business leaders last year at the annual meeting of the Clinton Global Initiative. A primary aim of Envision: Charlotte is to reduce energy use in the most urbanized part of Duke's headquarters city by at least 20% within five years.

"The purpose of the Smart Energy Now program [is] to demonstrate that customers receiving detailed, near-real-time information on their energy consumption and near-real-time data on aggregate community energy performance would change their behavior to create energy savings," the North Carolina Utilities Commission said in its order approving the three-year pilot, posted on the NCUC's website last week.

Duke spokeswoman Paige Layne said the program will involve as much as 17 million square feet of office space in 70 or more buildings in the heart of Charlotte, including the headquarters of Duke and Bank of America and offices owned or leased by other major employers.

The program will provide real-time energy consumption information to building managers, and display such data in the lobbies of participating buildings in displays supplied by Cisco. The pilot also will "test various forms of building owner and tenant engagement and education, such as website and social media, newsletters, public displays, training events for building managers and occupants, other community events, and academic partnerships," the NCUC said.

"We're talking with a lot of people now about the specific strategy for social media engagement," said Duke's Layne. "We're taking behavioral science into account, and looking at a lot of things, like Facebook, Twitter, blogs, and allowing occupants to weigh in."

The NCUC agreed with its public staff that Duke's planned $2.7 million investment is justified by the energy cost savings that participating customers would receive, and that Duke should be entitled to recover program costs and an appropriate share of the project's $2.3 million in net lost revenue under the utility's NCUC-approved "Save-a-Watt" plan.

That recovery will be permitted, the commission said, "provided that [the] pilot program is ultimately determined to be cost effective and is, subject to evaluation of the pilot, implemented as a fully deployed [energy efficiency] program."

The Save-a-Watt program — championed by Rogers, who views energy efficiency as Duke's "fifth fuel" – permits Duke to recover through a rate rider 75% of the avoided costs associated with demand-side management programs that shift demand from peak periods and 50% of the avoided costs tied to efficiency programs that reduce overall energy sales.

— Housley Carr

known as the 4-1-1 plan.

New Orleans believes FERC should not have allowed the two units to pull out without first holding an evidentiary hearing on the issues, said city attorney William Booth, a partner with SNR Denton in Washington. The council believes FERC would have required some obligation or fee of the exiting Entergy units if it had held an administrative hearing, Booth said February 16.

— Esther Whieldon

FINANCE

Gensler tries to quell Dodd-Frank fears, but industry, Republicans still doubtful

The chairman of the Commodity Futures Trading Commission attempted last week to assuage continued fears voiced by commercial hedgers like utilities, saying the agency does not want to impose new margin requirements on derivatives traders, nor does it want to require such rules for existing swaps deals.

"We'll get this margin thing right," Gensler said at a hearing before the House Financial Services Committee. "We understand congressional intent on that."

Gensler also said the CFTC was working with other federal and global regulators on setting up uniform market reforms and was open to changes to its contentious position limits proposal, which would impose federal limits on energy and other commodity futures and over-the-counter trades.

Asked if he would petition Congress for more time to implement the numerous reforms under the Dodd-Frank Wall Street Reform and Consumer Protection Act, he said the CFTC already has the authority to do so — and some of the new rules mandated by the law probably would not be in place by July as he had originally hoped. "It is a paradigm shift and we want to get it right," Gensler said.

The assurances did little to quell opposition from Republicans and industry representatives, who fear the rules the CFTC is still proposing will drive US market participants overseas, rob markets of liquidity and lead to hundreds of lost jobs.

On the sidelines of a separate hearing, of the House Agriculture Committee's Subcommittee on General Farm Commodities and Risk Management, Richard McMahon, vice president of energy supply and finance for the Edison Electric Institute, said energy firms are still concerned about the impact of Dodd-Frank, despite Gensler's assurances.

Utilities and other energy companies could still face margin requirements if they are caught up in the definition of swap dealer, and the industry will still be subject to transaction-by-transaction reporting requirements, McMahon said.

Also, questions remain about how the CFTC will expand its oversight authority over the electric utility industry, he said. Such issues include the question of jurisdiction the CFTC must address in now-overdue agreements with the Federal Energy Regulatory Commission and the possibility that the CFTC could regulate options on physical commodities as swaps.

"The end-user community is concerned about the CFTC's proposal because many contracts for delivery of power in the electric industry, such as capacity and requirements contracts, include price, volume or other optionality," McMahon said in his prepared testimony. "Including these end-user contracts in the definition of swap would greatly expand the scope of the CFTC's regulation over the electric utility industry and potentially would subject end-users to a number of burdensome regulatory requirements."

During the subcommittee hearing, John Damgard, president of the Futures Industry Association, said the proposed rules are excessive since they would also affect futures markets, which he said had nothing to do with the financial crisis of 2008.

"We weren't directly involved in any of the difficulties in the market, and I'm very proud of the fact that futures markets all over the world worked very, very smoothly through all that stress," Damgard said. "Futures markets have worked extremely well, there's nothing in Dodd-Frank that says you have to totally rewrite the rule book on an industry that worked perfectly well."

House Republicans at both hearings likewise voiced their dissent.

Representative Scott Garrett of New Jersey, chairman of Financial Services' Subcommittee on Capital Markets, said the CFTC's current proposed rules, if implemented, "would literally spell the end of US-based derivatives markets."

Garrett said he believed the CFTC was introducing the new OTC derivatives rules too rapidly, leaving businesses unable to set up new reporting systems and other architecture required by Dodd-Frank in time. "All that wasn't there in the past, you're trying to do it right now in a very expedited manner," he said.

Representative Ed Royce of California said that new, "onerous" rules would drive capital and end-users from US markets to Europe, Asia and South America.

Like Garrett, Representative Frank Lucas of Oklahoma, chairman of the Agriculture Committee, said the CFTC's rulemaking process was moving on a timeline that is unrealistic. And Representative Nan Hayworth of New York said the Dodd-Frank rules would turn the US into "an increasingly hostile environment" for investment.

— Brian Scheid

S&P sees some threats to public power systems from slow recovery and upcoming EPA rules

Public power systems' credit quality remains stronger than their investor-owned counterparts but could worsen with the slow economic recovery and upcoming environmental regulations, said Standard & Poor's Ratings in a new report.

"Alone, the recession and the tepid recovery that has followed would pose problems for the US public power sector. But we believe that potential US regulations that could be costly to comply with complicate matters further," warned Senior Director Peter Murphy and seven other analysts in "Regulatory Uncertainty And A Tepid Recovery Could Weaken The U.S. Public Power Sector's Credit Quality." S&P and Platts are units of The McGraw-Hill Companies.

"Although we expect credit quality to hold up in the next 12 months, we believe the long-term picture is less certain. And ratings could suffer for those utilities that do not, in our view, respond effectively to cost pressures."

Public systems' key credit strength compared to IOUs remains the ability of most to change rates without state or federal approval, but they are subject to political pressure to hold down rates, especially if customers are seen as not being able to afford them, S&P added.

But a key strength is public systems' focus on providing low cost power, making them more risk averse and less likely than IOUs to put capital in danger by diversifying into unregulated ventures like telecommunications and merchant power, Murphy pointed out.

S&P does not expect this Congress to enact significant environmental legislation so as with IOUs, significant federal action will come from the Environmental Protection Agency, including greenhouse gases, "maximum achievable control technology" for boilers and a revised clean air transport rule dealing with sulfur dioxide, nitrogen dioxide and nitric oxide.

Costly retrofits and/or operating costs will force shutdowns of some coal plants, and newer ones will be more expensive, S&P predicted. Most states have renewable portfolio standards, which could also boost costs, Murphy added.

"We believe it's too early to assess whether there will be any lasting credit impact on the electric sector from these regulations. The details of any final rules are as yet unknown. The key to recovering costs [for public systems] is both the essentiality of the service these utilities provide and (for most but not all) the ability to set their own rates without state utility commission oversight," S&P said.

Many public systems are, despite the uncertainty, assessing CO_2 footprints and estimating potential compliance costs ahead of regulation, but actual costs will depend on the details, and will vary by region and utility, S&P continued.

"Our interactions with issuers indicate that ahead of regulations, many utilities are focusing on conservation, demand-side management, and energy efficiency at both the production and end-user level in an effort to lower emissions. A secondary benefit [of that] is the delay or elimination altogether of a utility's need to install additional generation, which can result in substantial savings," it added.

S&P rates 80 wholesale public power systems (including multiple ratings for the same issuer): seven AA, 16 AA-, 20 A+, 15 A, 15 A-, two BBB+, four BBB, one BBB- (Missouri Joint Municipal Electric Utility Plum Point project). All have stable outlooks except Nebraska Public Power Generation Agency (A-) and Heartland (South Dakota) Consumers Power District (both A-), which have negative outlooks.

S&P rates 130 public retail power systems: four AA+ (Huntsville, Alabama; and Knoxville, Memphis, and Nashville & Davidson County, Tennessee); 10 AA, 25 AA-, 38 A+, 24 A, 23 A-, four BBB+, one BBB, and one BBB-, the Virgin Islands Water & Power Authority.

All have stable outlooks except Santa Clara, California and Greenville, Texas (both A).

It also rates 64 public retail systems with natural gas and/or water systems as well as electric: one AA+ (Springfield, Missouri); seven AA, 11 AA-, 12 A+, 21 A, eight A-, three BBB+ and one BBB (Williamstown, Kentucky).

— Paul Carlsen

EARNINGS

Bailing on renewables, CH Energy plans to focus on utility and fuel units and finally hike dividend

Following through on its third-quarter decision to divest ethanol and biomass power operations, CH Energy Group in Q4 decided to get out of other renewables and focus on utility Central Hudson Gas & Electric and nonregulated fuels unit Griffith Energy Services.

If their profits grow enough the holding company aims to finally raise the dividend — $2.16/share annually since Q3 1998.

With a $1.3 million Q4 impairment charge on a biomass plant following the $6.9 million Q3 impairment charge on its 12% stake in Cornhusker Holdings, owner of a Nebraska corn ethanol plant, 2010 net income fell 11.5% to $38.5 million, CHEG reported February 11.

In 2009 there was a gain of about $5.36 million or 44 cents/share on the sale of some Griffith assets.

Without those items, "normalized" net improved 22.4% to about $46.7 million and EPS from $2.42 to $2.96.

The company "lacks competitive advantage and sufficiently strong internal core competencies" in the renewables market and cannot earn an appropriate return on such investments without incurring debt inconsistent with credit quality objectives, it said in the Form 10-K, filed February 10.

"The earnings profile of renewable energy projects does not support [our] current strategy and near term financial objective to increase the dividend because the returns typically start low and increase over time," it added.

If earnings grow 5% from 2009's reported EPS of $2.76, the dividend can be raised while maintaining the target payout ratio of 65% to 70%, CHEG added.

The current ratio is 88.5% of reported basic 2010 earnings per share of $2.44, but 73% of "normalized" EPS of $2.96 without last year's impairment charges.

Dividend hike could be later this year, says CFO

"The earnings and cash flow provided from Griffith are supportive of and will continue to support our ability to achieve consolidated earnings growth of 5% per year on average over time and eventually raise the dividend," said Executive Vice President and CFO Christopher Capone, during the February 11 earnings conference call, according to a transcript posted on www.SeekingAlpha.com.

"We feel that given growth in the earnings power at Central Hudson and Griffith coupled with the impact of share repurchases we will be in a position to consider rating our dividend later in 2011 or early 2012."

The payout would be at the top of the target range initially but would slide over time, he added.

"We want to assure ourselves and the investment community that any increase will be sustainable and recurring," he said.

Special dividend considered and rejected

Asked whether CHEG would consider a special dividend rather than buybacks, Chairman, President and CEO Steven Lant said the board of directors had, and decided buybacks were a better way to return capital to investors.

"We look at the company as a growing concern and a special dividend really doesn't do as much for the going concern as it does for the shareholders at a particular holding date," he explained.

The Q4 impairment charge was on the 19-MW wood-fired Lyonsdale plant in Lyonsdale, New York, after several bids earlier this year indicated it was unlikely it would receive book value if sold.

Other renewable assets are CH Auburn, owner of a 3-MW landfill gas plant in Auburn, New York; CH Shirley, owner of a 90% stake in a 20-MW wind farm in Glenmore, Wisconsin, and a 50% stake in CH-Community Wind, a joint venture that owns 18% of two other wind projects.

CHEG is actively trying to sell Lyonsdale and Shirley and "will continue to evaluate the market for the remaining investments in 2011," it noted in the 10-K. Proceeds would be used to retire project debt and buy back stock.

Stock buybacks authorized in 2007 only began in Q4 2010

The board July 31, 2007 authorized buying back up to 2 million shares, but CHEG only started doing so in December 2010, repurchasing 29,562 shares. It also bought back 7,931 shares in the fourth quarter for tax withholdings on shares and options granted under executive compensation programs, for a total 37,493 shares during Q4 at an average $49.24/share.

CHEG also repurchased 106,400 shares this year through February 1, using available holding company cash and

FINANCE BRIEFS

Dominion Resources February 14 revised 2010 financial results by reversing the $75 million reserve booked in the fourth quarter for rate credits offered under a settlement that would have delayed **Dominion Virginia Power**'s next base rate case a year. The reversal boosted net income $48 million (after tax). The state **Corporation Commission** February 7 rejected the deal, which would have kept current rates — and the 11.9% allowed return on equity — in place until December 1, 2014 in exchange for the $75 million credit. Under last year's settlement of DVP's 2009 rate case, the next case is to begin in 2012 and new rates to take effect by December 1, 2013. The proposal was endorsed by the VCC staff, state attorney general's consumer division and several large customers. But it was opposed by several other large industrials, the Apartment and Office Building Association of Metropolitan Washington, and the Department of the Navy, representing all federal executive agencies. The VCC agreed with those opponents who argued that delaying the rate review until 2012 would violate a material term of the rate case settlement. With the reversal Dominion's Q4 2010 net income was revised from $250 million to $298 million, and 2010 net from $2.76 billion to $2.808 billion, still an all-time record and up from $1.29 billion in 2009. Dominion does not include such one-time items in what it terms "operating" net so that remains $366 million for last year, down $8 million.

… **Emera** February 11 said 2010 net income gained 8.8% to a record $191.1 million (Canadian) thanks partially to record net from utilities **Bangor-Hydro Electric** (up 16% to C$31.9 million) and **Nova Scotia Power** (up 11% to C$121.3 million). The Canadian dollar is currently worth about 99 cents (US), down from an average $1.03 in 2010, which was down 8.8% from 2009. **Maine & Maritimes**, acquired December 21, did not impact results. Emera's total power sales rose 11.1% to a record 15,708 GWh. BHE's were up 1.8% to 1,560 GWh and NSP's 1.3% to 11,455 GWh, but neither set new records. Emera's total includes sales from Emera Energy (not broken out in the earnings report), internal parent for the 600-MW Bear Swamp pumped-storage hydro plant in northern Massachusetts, of which Emera owns 50%, and the 260-MW gas-fired Bayside plant in St. John, New Brunswick, which sells its output to **New Brunswick Power** and also in **ISO New England**. The C$12 million increase in NSP net reflected lower income taxes of C$59.6 million, from lower pre-tax earnings, higher deductions for renewable investments and higher estimated future deductions. That more than offset higher expenses, mainly for pensions and storms (C$22.4 million), and lower electric margin mainly on credits to customers for over-recovered 2009 fuel costs (C$11.6 million) (all after tax). Emera reported BHE financial details in US dollars, in which net jumped 26.6% to $30.9 million, higher than the gain in Canadian dollars because the latter was worth less in US dollars than in 2009. BHE benefitted from transmission rate increases ($6.2 million) and higher revenue from regionally funded transmission investments ($7.5 million), partially offset by higher expenses ($5.4 million) (all after tax) and income taxes ($4.7 million).

… Fitch Ratings February 15 upgraded **Lubbock (Texas) Power & Light** electric light and power system revenue bonds from A- to A+ citing the October 29, 2010 acquisition of **Southwestern Electric Power**'s 24,000 customers in the city for about $87 million. Before that the municipal system had about 62,500 customers and about 63% of the city's market share, as LP&L and SPS had separate systems with parallel distribution lines throughout the service territory since 1942, Fitch noted. "The acquisition effectively buys out LP&L's principal competitor and results in an enterprise business risk more in-line with comparable public power retail systems. While some competition still exists, it is very limited and confined to a small section of the service area," noted Director Eric Espino and Senior Director Christopher Jumper. "While the transaction has lead to a roughly doubling of LP&L's debt, the elimination of direct competition helps to mitigate this concern. Additionally, the shorter-term increase in leverage is also somewhat offset by the expected savings in fixed expenses as a result of the acquisition." Ratings also reflect the past support provided by city government (rated AA+) when the utility has had financial difficulty, Fitch added. Most LP&L debt matures by 2020, providing flexibility for future issuances, and leverage is still lower than the median for munis rated A+, Fitch continued. LP&L also benefits from competitive rates, thanks to the wholesale power supply deal with SPS, Fitch noted.

… Vectren February 16 said 2010 net income inched up $600,000 to $133.7 million. A 15.4% gain in Utility Group net to $123.9 million was mostly offset by lower results in most other segments. Hotter weather boosted utility net $8.1 million. Retail power sales gained 11.4% to 5,617 GWh — the highest since the 2007 record of 6,216 GWh — led by a 16.4% leap in industrial to a record 2,630 GWh, which beat the 2005 mark. Among the power sector companies reporting results through February 17, only Vectren had record industrial volume last year. With cooling degree days 134% of "normal," up from 90%, residential sales went up 10.5% to 1,603 GWh, the highest since the 2007 record. Commercial rose 3.9% to 1,360 GWh, the first increase since 2007. Wholesale dipped 2.6% to 588 GWh, the lowest since before 2000 (as far back as data goes), so while total sales improved 9.9% to 6,204 GWh that was still the second lowest for any year since before 2000. Energy Marketing, mainly natural gas marketer **ProLiance**, lost $4.2 million, down from a $4.1 million profit which included an $11.9 million charge on its investment in Liberty Gas Storage. More shale gas and lower industrial gas demand meant plentiful supply and less price volatility, reducing opportunities to optimize ProLiance's transportation and storage capacity, Vectren noted. "2011 will continue to be a very challenging year for gas marketers like ProLiance," it added, predicting a 10 to 20 cents/share net loss. With that Vectren expects 2011 EPS of $1.60 to $1.85, including $1.45 to $1.55 from the Utility Group. In other segments, coal mining net fell 11.2% to $11.9 million and energy services 29.2% to $6.4 million. "Other businesses" net loss jumped 196% to $7.4 million, including a $6.9 million charge on "legacy investments." Infrastructure services rose 29.2% to $3.1 million.

planned to buy about another 93,600 "in the next few days," Capone noted.

"We will consider repurchasing additional shares throughout 2011 using additional available holding company cash upstreamed from our operating companies and investments … and our renewable asset divestitures. At this juncture it's too early to estimate the amount from that next round," he said.

Electric net gains 31.3% on rate increases

CHG&E electric net gained $7.9 million or 31.3% to $33.1 million, with no benefit from hotter weather since decoupling took effect July 1, 2009.

Under the three-year rate plan approved by the Public Service Commission June 18, power rates went up $11.8 million July 1, 2010 and are to increase another $9.3 million July 1, 2011 and $9.1 million a year after that.

With cooling degree days surging 76%, power sales went up for the first year since 2007, by 0.8% to 5,215 GWh, led by a 3.7% hike in residential, to 2,078 GWh. Commercial increased 1.2% to 1, 968 GWh. But industrial slid 4.8% to 1,113 GWh, a new annual low.

Weather normalized, however, sales fell 1.9%, with industrial down 4.8%, residential 0.9% and commercial 1.3%.

CHG&E's peak load last year was 1,229 MW July 6, up 11% from 2009 and the highest since the record 1,295 MW August 2, 2006.

CHG&E natural gas net jumped 81.8% to $12 million. Under the rate plan rates went up $5.7 million July 1, 2010, to be followed by hikes of $2.4 million and $1.6 million in rate years two and three.

At Griffith, headquartered in Columbia, Maryland, net income plunged 85% to $1.8 million reflecting the December 11, 2009, sale of operations with about 45,000 customers in five Northeastern states. It now has about 57,000 customers in Delaware, Washington, DC, Maryland, Pennsylvania, Virginia and West Virginia.

Griffith sells heating oil, gasoline, diesel fuel, kerosene, and propane and installs and maintains heating, ventilating, and air conditioning systems.

With the charges the net loss from CH Energy's "other businesses and investments" leaped from $300,000 to $8.4 million.

— Paul Carlsen

Rogers outlines Progress' merger filings; 2010 profits up despite one-time items

Duke Energy laid out a rough schedule for filing regulatory applications for its proposed $25.9 billion acquisition of Progress Energy during last week's 2010 earnings conference call.

By the end of March, Duke plans to file applications with the Federal Energy Regulatory Commission, North Carolina Utilities Commission and Kentucky Public Service Commission, as well as an application with the Nuclear Regulatory Commission for the "indirect transfer" of Progress' nuclear operating licenses to Duke.

By the end of the second quarter, Duke plans to file for antitrust review by the US Department of Justice under the Hart-Scott-Rodino Act, and an application with the South Carolina Public Service Commission by early in the third quarter for approval of "combined operational control" of Duke's and Progress' generation assets "via a joint dispatch agreement."

Chairman, President and CEO James Rogers said, "merger teams have begun initial integration planning" with the aim of jointly dispatching the combined companies' Carolinas assets. "To achieve earnings accretion in 2012, we must aggressively and relentlessly identify and pursue cost savings opportunities this year," he noted.

In mid-January, Duke announced the acquisition, which would create the nation's largest electric company, give it access to lower-cost capital and a less risky corporate profile (*EUW*, 17 Jan, 1).

Net income improves as hot weather bolsters utilities

Despite several one-time items in both years — mainly the Q2 2010 impairment charge of $602 million to write off the remaining "goodwill" on Ohio coal plants, in the Commercial Power segment — reported net 2010 income improved 22.8% to $1.32 billion, mainly on higher utility profits.

Last year's net was trimmed by the impairment charges (up 46.8% from 2009 charges on the same plants), job cuts and office consolidations ($105 million), litigation reserves ($16 million), and costs related to the 2006 acquisition of Cinergy ($17 million, up $2 million).

Those were partially offset by asset sales ($154 million) and "mark-to-market" unrealized gains ($21 million, up from a $38 million loss) (all amounts after tax).

Without those, "adjusted" net gained 19.3% to $1.882 billion, with basic and diluted earnings per share up 17.2% to $1.43. Duke initiated adjusted EPS guidance for 2011 at $1.35 to 1.40 (diluted).

Duke reports segment results in earnings before interest and taxes. Reported EBIT improved 20.5% to $2.97 billion and adjusted EBIT 17.9% to $3.57 billion.

US Franchised Electric & Gas reported and adjusted EBIT gained 27.8% to $2.97 billion — mainly because the job cut and consolidation costs were booked in the "other" segment.

The utilities benefitted from hotter weather ($308 million), Carolinas rate adjustments ($293 million), higher equity allowance for funds used during construction and higher pricing and rate riders ($81 million each), and higher weather-normalized sales ($40 million). Those were partially offset by higher operation and maintenance costs ($108 million) and the impairment charge on the Indiana settlement ($44 million).

With cooling degree days up 31.5% to a new record, Duke Carolinas retail sales rose 7% to 78,922 GWh, only 197 GWh short of the 2007 record.

Residential gained 10.2% to 30,049 GWh and commercial 3.7% to 27,968 GWh, both beating 2007 marks.

Industrial went up 7.4% to 20,618 GWh, the first increase since 2005, but still the second lowest for any year since before

1995 (as far back as data goes).

With CDDs surging 67.3% Duke Midwest retail rose 6.8% to 53,165 GWh, led by a 10.4% hike in industrial, to 15,982 GWh. Residential were up 8.2% and commercial 2.7% but none set new records.

Weather-normalized, however, total sales gained only 1.9% and Duke expects only about 1% this year. In 2010 residential and commercial were both flat and Duke expects growth of less than 1% this year.

All of 2010's weather-normalized growth was industrial (7%) but Duke sees only 2% growth this year.

Commercial Power posts loss on impairment

With the impairment charge, Commercial Power lost $229 million, down from EBIT of $27 million. The Q2 impairment charge was $660 million, up from $413 million in Q3 2009. "Mark-to-market" gains were $33 million, up from a $60 million loss.

Without those, adjusted EBIT slid 20.4% to $398 million, reflecting lower volume from Ohio customer switching ($116 million) and lower gains on sales of coal and emission allowances ($103 million), partially offset by higher profits from the Midwest gas plants ($85 million).

Duke Energy International gained 33.1% to $486 million, on higher prices in Brazil, favorable exchange rates and higher profits from National Methanol.

In the "other" segment the loss before interest and taxes" was up $4 million to $255 million, reflecting $248 million of gains on asset sales: $139 million from half of DukeNet Communications and $109 million from Q-Comm, a regional fiber optic transport and competitive local exchange carrier.

That was more than offset by $172 million of job cut and office consolidation costs, $26 million of litigation reserves and $27 million of costs related to the 2006 acquisition of Cinergy (up $2 million).

Slight drop in adjusted 2010 earnings predicted

Duke expects 2011 adjusted EBIT to dip 0.9% to $3.54 billion, led by $550 million from DEI (up 13.2%) thanks mainly to higher prices in Brazil.

Duke sees USFE&G adjusted EBIT rising only 1% to $2.995 billion, based on the weather-normalized sales forecast. Most of the EBIT gain would come from earnings on capital spending on system modernization.

Commercial Power adjusted EBIT is seen sagging 46% to $215 million, with lower profits from the Midwest natural gas plants and customer switching in Ohio. Duke expects the "other" adjusted loss to slide 20.9% to $220 million.

— Paul Carlsen

EFH to take $20 million charge for losing plant during early February cold snap

Energy Future Holdings expects to take a $20 million after-tax charge against first-quarter earnings as a result of the cold weather in Texas at the start of February, the utility holding company said February 7.

In a Form 8-K, EFH said a number of power plants operated

Power industry Q4 and full year 2010 financial results

Reported week ending February 17 ($millions)

	Fourth quarter						2010					
	Revenue		Net income		Basic EPS		Revenue		Net income		Basic EPS	
	$	%	$	%	$	%	$	%	$	%	$	%
Allete	$238.1	+10.2	$13.3	-28.9	0.38	-32.1	$907.0	+19.5	$75.3	+23.4	$2.20	+16.4
Avista	374.4	-7.2	25.7	16.7	0.45	+12.5	1,558.7	+3.0	92.4	+6.1	1.66	+4.4
CH Energy Group*	241.2	+2.7	9.8	-41.4	0.62	-41.5	972.3	+4.4	39.2	-11.5	2.44	-11.6
DPL Inc.	469.5	+15.8	71.5	43.3	0.62	+44.2	1,883.1	+18.5	290.3	+26.7	2.51	+23.6
Duke Energy*	3,445.0	+10.8	**427.0**	23.4	0.32	+23.1	14,272.0	+12.1	1,320.0	+22.8	1.00	+20.5
FirstEnergy*	3,217.0	+8.7	185.0	-22.2	0.61	-21.8	13,339	+2.8	784.0	-22.1	2.58	-22.0
NorthWestern	291.7	-3.5	22.6	-11.8	0.63	-10.0	1,110.7	-2.7	77.4	+5.4	2.14	+5.4
OGE Energy	828.5	+7.1	30.7	-10.2	0.32	-8.6	3,716.9	+29.5	**295.3**	+14.3	3.03	+13.1
PG&E Corp.*	3,621.0	+2.3	250.0	-8.4	0.63	-12.5	13,841.0	+3.3	1,099.0	-9.9	2.86	-12.0
Scana*	1,145.0	+4.7	**95.0**	+25.0	0.74	+19.3	4,601.0	+8.6	376.0	+8.0	2.99	+4.9
Vectren*	564.1	-0.8	45.4	-16.8	0.56	-17.6	2,129.50	+1.9	133.7	+0.1	1.65	–
Industry total so far — reported net			4,260.40	-49.2					20,602.60	-9.7		
— 'adjusted/operating/ongoing' net			4,421.90	-2.1					23,207.30	+9.7		

*See story this issue

Boldface: record net income for period

Sources: company earnings statements and presentations by generation subsidiary Luminant tripped February 2, which meant the group lost money on the power the units would have produced and on the electricity it had to buy to meet commitments in the Electric Reliability Council of Texas.

As a result, the parent company's earnings will take a $30 million pre-tax hit in the first quarter and it could face similar woes in later earnings periods due to settlement procedures in ERCOT, EFH said.

Four lignite-fired Luminant units in central Texas experienced frozen instrumentation or controls that led to immediate unit trips between 1 a.m. CST and 6 a.m. CST that day.

Luminant "immediately began efforts to restore the units to service," and all four were online again by 10 p.m. CST February 3, EFH added. Some of Luminant's natural gas-fired units also tripped offline during the "weather event" and were restored to service by February 3.

Luminant's Texas Competitive Electric Holdings unit needed to buy power at higher-than-expected market prices to meet wholesale and retail contractual obligations during the storm, which knocked out more than just its own plants.

The shuttering of the Luminant units and others in the early hours of February led to rolling blackouts across the state in the following couple of days and investigations are under way at both the state and federal level.

EFH said the full impact of the storm on its earnings will not be known for six months as a result of ERCOT settlement procedures.

Settlement information for most operating activities is due from ERCOT within two months of an operating day, and "true-up settlements" are due from ERCOT within six months after an operating day, it said.

"As a result, TCEH is subject to settlement adjustments from ERCOT for up to six months, which may result in changes or credits impacting TCEH's future reported results of operations," it said.

Some 7,000 MW of generation — including TCEH units — went offline in the early hours of February 2. EFH said Luminant made every effort to prepare for the "weather event," noting that it deployed "additional heating equipment, wind barriers and on-site personnel" on top of its usual winter preparation efforts.

— Keiron Greenhalgh

PG&E net slides 9.9% to lowest since 2006 with more charges on San Bruno explosion

PG&E Corp. doubled its previous estimate of the costs from the September natural gas pipeline explosion that killed eight people and destroyed 38 homes in San Bruno.

Releasing 2010 results, PG&E said as a result of efforts under way and additional pipeline testing and inspection that may be required, the estimated range for 2011 direct costs has increased to $200 million to $300 million (pre-tax) up from $100 million to $150 million for 2010 and 2011 combined.

Third-party liability in 2011 could range from nothing to $180 million, pre-tax. Those charges, if any, would come in addition to the $220 million provision for third-party liability the company booked in the third quarter.

Projected results for 2011 do not reflect any insurance recoveries, which may not occur until after this year, PG&E added.

PG&E "does not take this lightly," said Peter Darbee, chairman, president and CEO, during the February 17 earnings conference call.

The company must work to regain the confidence of customers because of the accident, he acknowledged.

The National Transportation Safety Board has not yet determined the root cause of the explosion, noted Kent Harvey, senior vice president and CFO. Once that happens, more costs could be incurred, he warned. PG&E is developing plans to modernize the decades-old gas pipeline system.

"The NTSB has publicly issued some preliminary reports and has announced that it will hold fact-finding hearings on March 1-3, 2011 to learn more about the San Bruno accident and important safety issues," the company noted in the Form 10-K, also filed February 17.

Net slides 9.9% to lowest since 2006

With another $27 million of fourth-quarter charges on the disaster, bringing the total to $168 million (after tax), 2010 reported net income fell 9.9% to $1.099 billion, the lowest since $991 million in 2006 — the last year PG&E earned less than $1 billion.

Without that and other one-time items, "net from operations" improved 8.8% to $1.331 billion despite lower power sales at Pacific Gas & Electric.

Net was also cut by costs of the unsuccessful ballot initiative aimed at hindering formation of municipal systems ($45 million), and the loss of future tax benefits under the health care law ($19 million).

In 2009 reported net was cut by accelerated work on the natural gas system ($59 million) and job cut costs ($38 million), mostly offset by interest earned on a tax refund ($66 million) and recovery of costs tied to the sale of hydroelectric plants ($28 million).

PG&E maintained guidance for 2011 earnings from operations at $3.65 to $3.80/share, an estimate first given in the Q3 2009 earnings call. That would be up from $3.42 last year, compared to $3.21 in 2009.

But with the higher San Bruno costs, it trimmed the forecast for reported EPS to $2.94 to $3.50, down from the $3.27 to $3.72 given in the Q3 2010 earnings call.

Most of last year's increase was on higher rates at Pacific Gas & Electric (23 cents), plus lower costs for nuclear refueling outages (5 cents), "miscellaneous items" (4 cents), disability (3 cents), uncollectible bills (2 cents). Those were partially offset by higher costs for SmartMeter installation (5 cents), storms and outages (4 cents), lower energy efficiency incentives (1 cent), and the 3.8% increase in average basic shares, to 382 million.

Power sales fall for second year

Total, residential, and commercial power deliveries all fell for the second year from their 2008 records, with total down 2% to 83,908 GWh. Residential dipped 1.6% and commercial 0.3%.

Industrial dropped 2.6% as customers fell 2.4% to 1,254.

But with decoupling, the lower sales did not impact profits.

Asked about PG&E's renewables procurement plans, Darbee said the company is more likely to pursue solar resources than wind resources. When it gets hottest in PG&E's territory, Darbee said, "it is usually because the wind is not blowing."

Also in solar power's favor is the fact that the cost of these resources is coming down, Darbee added.

— Paul Carlsen, Jeff Barber, Lisa Weinzimer

Scana stock sags on lower earnings forecast despite dividend hike and higher 2010 profit

Despite higher 2010 profits, Scana stock sagged and stayed down as it lowered the forecast for average earnings growth over the next three to five years to a range of 3% to 5% from the previous 4% to 6%.

"We are not talking about a huge change. Our philosophy is to make sure we commit to you what we're confident we can deliver," said Senior Vice President and CFO Jimmy Addison, during the February 11 earnings conference call.

But that day, the stock traded as low as $39.90 before closing down $1.74 or 4.1% at $40.67, as volume surged to 5.1 million shares, 9.5 times the 30-day average.

On February 17 it gained 0.8% to $40.57, but that was still down 4.3% in a week. It was up 15.8% in a year and 43.9% in 10 years — but only 4 cents in five years.

Peppered by analysts about why the forecast was cut, even though 2010 net income improved $28 million or 8% to $376 million and earnings per share from $2.85 to $2.99, Addison and other executives said they were assuming a slow economic recovery and noted that customers are holding down consumption.

"While we are beginning to see signs of longer term economic recovery in our service territories, we remain conservative in our estimates and cautiously optimistic about our longer term sustained recovery," cautioned Addison, according to a transcript posted on www.SeekingAlpha.com.

Paul Patterson of Glenrock Associates asked whether any particular event prompted the lower growth outlook.

Since South Carolina Electric & Gas implemented electric weather normalization beginning with August bills, it has become clearer what is happening with non-weather related usage, said Chairman, President and CEO Kevin Marsh.

"You've got the new light bulb standards coming in, you continue to see I think a higher penetration rate of more efficient air conditioning units," he pointed out.

"Another thing that's going on I suspect around the country, I know in the Southeast is that the new [residential] customer just being added today is typically the smaller residence, a more energy conserving home than was built in the past. So the 6,000 customers we added this past year use a little less energy that did 6,000 customers from a couple of years ago."

"Part of it is the lack of growth that we've had in the past. It's about half of what it's been. Although it's better than many of the country it's slightly under 1% [weather normalized]," agreed Addison. "The challenge that our industry is facing and we certainly are is that the average customer is using slightly less electricity in that same home they were in three years ago … We just don't have that historical growth in margins from new customers that we have had in the past."

Asked by Christopher Ellinghaus of Wellington Shields whether the lower forecast might be too conservative, especially since Scana pointed to new service territory facilities being planned by Amazon and Boeing, Addison responded, "I hope that's the case. But only the future will really answer that. If the economy does pick up more than we think [we'll be overjoyed] to come back and raise that [earnings estimate] in the future."

Those new facilities will not be consuming power for one to two years, noted Marsh: "it's going to take 12, 24 months to play out on those major announcements and we just want to see it in hand before we're making commitments for three to five years out."

Asked whether the outlook could be revised again, Marsh said, "I think that's very unlikely. I feet like we've got a real good handle out of what's going on here … I would say we were probably a little conservative."

Profit growth all on higher utility margin

All of the increase came on higher margin at South Carolina Electric & Gas, with electric up 60 cents or about $75.4 million and natural gas 15 cents or about $18.8 million.

Those were mostly offset by higher operation and main-

Power company 4th quarter 2010 earnings release schedule

February 22 (Tuesday)

■ Ameren, ■ El Paso Electric, ■ ITC Holdings*, ■ *NRG Energy, ■ Ormat Technologies*, ■ Public Service Enterprise Group, ■ UIL Holdings*

February 23 (Wednesday)

■ *Idacorp, ■ Integrys Energy Group*

February 24 (Thursday)

■ *CMS Energy, ■ Cleco*, ■ Great Plains Energy*, ■ Northeast Utilities,* ■ *Sempra Energy, ■ *TransAlta, ■ Westar Energy*

February 25 (Friday)

■ *Pepco Holdings, ■ Portland General Electric

February 28 (Monday)

■ Edison International, ■*Unisource Energy

March 1 (Tuesday)

■ CenterPoint Energy, ■ *GenOn Energy, ■ *PNM Resources,

March 3 (Thursday)

■ Algonquin Power & Utilities

March 15 (Tuesday)

■ *Central Vermont Public Service

before stock markets open after stock markets close
Sources: company press releases and web sites

tenance (15 cents), depreciation (10 cents), share dilution and higher interest costs net of allowance for funds used during construction (9 cents each), and higher property taxes (7 cents).

Retail power sales gained 8.5% to a record 22,919 GWh, beating the 2007 mark, led by an 11.4% hike in residential, to 8,791 GWh — the fourth straight record.

Commercial went up 4.5% to 7,684 GWh, also beating the 2007 record. Industrial rose 10.1% to 5,863 GWh, the first annual gain since the record 6,775 GWh in 2004.

However, wholesale dipped 10 GWh to 1,965 GWh, the fourth straight drop. So total sales went up 7.7% to 24,884 GWh and the record remains 25,309 GWh in 2005.

Dividend hiked for 13th straight year

Also February 11 Scana raised the quarterly dividend on common stock 2.1% to 48.5 cents ($1.94 annually). This follows a 1.1% hike paid in second-quarter 2010 and is the 13th straight annual increase following the 28.6% cut to $1.10 in Q4 1999.

The new dividend is payable April 1 to shareholders of record March 10 and represents a payout ratio of 64.9% of 2010 basic earnings per share of $2.99.

At the February 17 closing price the new dividend yield would be 4.8%.

The payout ratio is higher than Scana's 55% to 60% target because of the recession, said Marsh.

"We plan on having increases but that's going to largely be driven by what happens in the economy … we plan to keep increasing and the economy would have to really go south for that to change," he added.

— Paul Carlsen

Message keeps coming: Utilities can handle EPA rules, agency not out to 'punish' *... from page 1*

mental controls," Eggers said in an interview after speaking at the 2011 National Electricity Forum in Washington. That pattern "has been pretty consistent across jurisdictions. They've been treated fairly."

Electric utilities are bracing for proposals in March from the Environmental Protection Agency to reduce emissions of mercury and other toxic air pollutants from power plants and to require construction of cooling water intake structures at power plants that withdraw above 2 million gallons a day.

The toxics rule will clamp down on hard-to-capture mercury pollution from power plants for the first time. EPA will issue the final rule in November 2011 with a three-year compliance schedule and the possibility of a one-year extension. The cooling water rule is to be finalized in July 2012.

Southern Company, one of the largest coal-fired utilities, is raising concerns about how consumers and electric reliability will be affected by these rules and a suite of others from EPA aimed at controlling pollution from the power sector in the next two to three years. A longer lead time to comply and make deliberate investments is in order to guard against reliability risks or excessive consumer costs, according to the Atlanta-based company which generates more than 42,000 MW.

Credit Suisse said it has not analyzed consumer impacts stemming from EPA's pending rules, but how a delay in the rules would help or hinder a utilities' bottom line is murky at best, according to Eggers.

A delay in implementation "will spread out the investment and defer when rate increases go to customers," he said. "How regulators treat that and how the cost structure of the investments change is too hard to say right now."

Whether there will be more investment required because of increased fuel, labor or construction equipment costs in the future if the rules are postponed is too hard to say, he said. "It's a murky crystal ball."

Still, Southern, which is 57% coal, 25% natural gas and 15% nuclear, continues to push EPA to hold off on these regulations and raises the specter of calling on its friends on Capitol Hill if necessary.

"We know all these decisions are significant," said Anthony Topazi, Southern's executive vice president and chief operating officer, who participated in a panel discussion with Eggers on EPA regulations and their impact on electricity infrastructure.

"Every coal plant we have will have significant costs associated with it, and the timeline will be critical," Topazi said. Investments to meet the EPA rules could run up to $300 billion industry wide, he said.

EPA Assistant Administrator Gina McCarthy, who shared the stage with Topazi and Eggers, said the agency is under a court order and cannot delay issuance of the rules. She noted that the rules for mercury, nitrogen oxides and sulfur dioxide are not a surprise and have been in the works for several years, after court remands back to EPA of faulty air regulations crafted during the Bush administration.

The agency has indicated it will be flexible, still companies should start planning now to ensure they will be in compliance, she said.

"If we see the best effort is being made, if you're doing the best you can, it is not in the best interest of EPA to punish companies for failing by a few months," McCarthy said.

Topazi said 60% of Southern's flagship coal units are controlled for air pollution with scrubbers and selective catalytic reduction equipment, but the utility expects more investments to meet EPA's mercury rule. Marginal units will require plant-by-plant decisions, he said. Some may be controlled, others replaced, and more generation may have to be purchased in the marketplace, he said.

"We do integrated resource planning and we have active RFPs looking for generation," he said, but then there is the question of getting firm transmission service or firm gas transportation.

"There is not headroom for that firm service to be provided without investment. Investment takes time," Topazi said. "The elephant in the room is the reliability issue. It is severe."

The Clean Air Act, under which EPA is mandated to carry out these rules on the power sector, "did not contemplate a suite of changes being done and deploying that capital in a three-year period," Topazi said. "Allowance for more time is necessary. We are the companies that have the reliability issue."

EPA rules to be legally defensible

McCarthy said not only will the rules go forward, they will be written in a way to sustain legal challenges that so often result in a delay of environmental regulations.

"We are not going to have rules susceptible to legal challenge so we can sit here 10 years from now debating if we have enough time," McCarthy told the forum, which was sponsored by the Department of Energy and the National Association of Regulatory Utility Commissioners.

"We're going to write them well, be sensitive to cost and reliability … but they will be legally defensible and they will demand compliance," she said.

McCarthy also emphasized that EPA would be mindful when it comes to reliability and not seek a cleaner energy mix by moving the industry toward a single fuel.

"EPA has never shut down a facility necessary for reliability, and we intend to maintain that record," she said.

In addition to the mercury rule and the cooling water proposal, EPA is to finalize the Transport Rule this year to reduce interstate air pollution from power plants.

The agency in July also is scheduled to propose "new source performance standards" for greenhouse gas emitted from existing, new and modified fossil fuel generating plants. The NSPS rule must be finalized in May 2012. In January, EPA finalized GHG rules for "prevention of significant deterioration" and operating permits for new and modified oil refineries and power plants.

Of the country's 991 coal-fired generating units, 478 units remain uncontrolled for major pollutants and a large majority of them are more than 30 years old.

Last year, Colorado Governor Bill Ritter signed a state mandate for utilities to cut their emissions 80% by 2017. Ron Binz, chairman of the Colorado Public Utilities Commission and of NARUC's climate task force, told the forum that reductions are being made with consumer costs and reliability in mind.

Xcel Energy, the state's biggest utility, brought the commission two dozen scenarios to address emissions from 10 aging coal-fired plants. It was "like a very big complicated puzzle," Binz said, but "it can be done."

In a separate event last week, EPA's McCarthy, as she has done on several occasions in the last several months, sought to allay utility concerns about what the industry has described as a "train wreck" of EPA regulations, noting that the Clean Air Act does not prevent EPA from considering the same technologies to reduce a variety of air pollutants.

"Right now, this agency is doing its best to tell the utility industry everything you need to achieve moving forward, so that one investment decision can be made over the next few years that will achieve compliance with the suite of rules that the agency is moving forward to address for public health," McCarthy told state regulators at NARUC's annual Winter Meeting in Washington.

In drafting and imposing a half-dozen rules this year and next, EPA will take a "sector-based approach" to long overdue requirements for electric utilities, she said.

"All the new rules we have moving forward at EPA move in the same direction concerning the same tools that makes one problem achieve resolution on another problem," she said.

McCarthy urged the state commissioners to encourage utilities and generators in their states to begin planning now for the EPA rules and to take early action. She also asked them to support energy efficiency and demand response as a way to flatten peak load and reduce demand overall. Public utility commissions also should explore ways to reduce rate impacts and make use of smart grid technology and rate structure options, she said.

"You know how to make decisions in the face of uncertainty," McCarthy said. "In the universe of uncertainty, these regulations won't be that uncertain."

In an interview after McCarthy's address, David Owens, executive vice president of the Edison Electric Institute, said the lobby for investor-owned utilities would not try to delay EPA's rules but see how workable they are once they are issued.

"If we have flexibility where the state PUCs, state legislatures and the federal EPA can work together and look at leveling out the cost and look at ways that there is not an adverse reliability impact, [then] this can get done," Owens said. His remarks echoed what other EEI executives told Wall Street analysts the previous week (*EUW*, 14 Feb, 1).

The industry remains concerned about the cumulative impacts of the numerous EPA rules coming out, Owens said. Flexibility by all regulators will be key to their success, he said.

"Once the rules are out, we'll get a chance to look at them in greater detail and see if this is the level of flexibility that was talked about today," Owens said. "Individual companies will be able to assess the impact on their individual systems and the impact on their consumers."

Congress fits and starts over EPA regs

Meanwhile, Republicans in control of the House of Representatives threatened to use a "must-pass" budget resolution to block EPA from imposing greenhouse gas regulations this year. Its fate is less clear in the Senate and in the White House.

As for federal legislation to provide more flexible mechanisms to control mercury, SO2 and NOx, the chief drafter of a bill said he was "on sabbatical" while the utilities determine their best avenue: EPA rules or a congressional alternative.

"We'll let the utilities have an opportunity to figure out if they're better off with a regular regulatory approach," said Senator Tom Carper, a Delaware Democrat. "Maybe they'll take another look at a legislative option. We're just on sabbatical."

At press time, House leaders had not said exactly when they would vote on the "continuing resolution" to fund the federal government. The measure had attracted hundreds of amendments.

But its provision to block EPA's use of funds for states to carry out the GHG rules faces an uncertain future in the Senate, where other approaches are likely to be considered. It got a cool reception from Senate Democrats who hail from coal states and opposed legislation last year for a GHG cap and trade scheme. Democrats still control the Senate and its agenda.

"I doubt it," said Finance Committee Chairman Max Baucus, a Montana Democrat, when asked whether the Senate would approve the House Republicans' provision to stop EPA GHG rules as part of the budget resolution.

Wyoming Democrat Jon Tester said the concept of "defunding" EPA as a means to halt GHG regulation did not sit well with him. "Defunding an agency makes it so government doesn't work, then there can be made a claim that government doesn't work," Tester said. "That isn't good. Government has got to be able to work."

Senator Ben Nelson of Nebraska said he would have to study the House Republicans' resolution to stop EPA.

"I'm not opposed to what House Republicans are attempting to do, I just want to see how they go about doing it," Nelson said in an interview.

Of all the options so far to block EPA's GHG rules, Nelson said he supports legislation by his fellow Democrat Jay Rockefeller to suspend the agency's authority for two years. The West Virginia senator's bill, S. 231, has six Democratic cosponsors. Nelson also supported a 2010 resolution by Alaska Republican Lisa Murkowski to reverse EPA's authority under the Clean Air Act permanently.

Keeping utility rates affordable is a key issue in Congress in the face of the economy and global trade, according to Nelson. Many fear GHG rules will raise electricity costs.

"It will be a key point up here, no doubt about it," he said. "We have to be sure that if we want to push international trade and export that we don't add undue cost to the products that are being produced here in America."

— Cathy Cash

Geomagnetic storms flare up, put utilities on guard, NERC announces task force

... from page 1

tiatives like the smart grid, the power system is much more vulnerable than it used to be, he pointed out. By extension, much of the country's infrastructure is, too.

At the National Association of Regulatory Utility Commissioners winter committee meetings, Schnurr said major geomagnetic storms can have massive impacts on high-voltage transformers that mediate grid flows and are uniquely susceptible to this problem. He referred to the transformers damaged in a March 1989 geomagnetic storm that blacked out Hydro-Quebec's grid.

"We're talking about physically melting large components of these 250-ton class components," Schnurr said. Such transformers can take five to 10 years to replace, he said, and this could cause "a blackout lasting up to 10 years or longer … It's a quite serious problem."

According to the North American Electric Reliability Corp., the purpose of its new Severe Impact Resilience Task Force is to provide guidance and options to enhance the system's resilience to withstand and recover from geomagnetic disturbances, as well as coordinated physical attack and cyber attacks.

Creation of the task force stemmed from the a "High Impact, Low Frequency Risk to the North American Bulk Power System" report done by NERC and the Department of Energy, and the Electricity Sub-sector Coordinating Council's "Critical Infrastructure Roadmap," which identified strategies to deal with such impacts.

The task force will propose approaches, practices and plans to reduce the impact of severe impact events through effective emergency operations and timely restoration of the bulk power system, NERC said.

"NERC and the electricity industry are building on their century-long experience in managing complex risks to protect the electricity infrastructure and enhance its resilience," said NERC President and CEO Gerry Cauley.

Tom Bowe, executive director of reliability integration at PJM Interconnection and chairman of the task force, also appeared at the NARUC meeting, saying the task force of more than 50 people already has "an incredible amount of energy committed to this topic."

The goal is to figure out "how are we in the industry going to develop the strategies and options to keep people thinking when they are in the midst of an event they never envisioned," Bowe said.

"If we do our work right, hopefully we will have some response and communication protocols," such as those developed in Y2K contingency plans developed to address fears about computer shut-downs in 2000," he said.

Operator training is also essential, he said, because "it's going to be those operators in those first few minutes and how they respond in a creative fashion that are going to carry the day." Companies suffering through a recession often reduce training because of budgetary concerns, "but it's through training that I think we really make the investments to be resilient — because this is really a people thing," Bowe said.

Last week, NOAA's National Weather Service said there was a series of major solar flares and the sun was clearly "waking up from several years of relative quiet."

"Activities on the sun's surface tracked and forecast by NOAA satellites and scientists can blast Earth with magnetic events that can damage the electrical grid and temporarily damage radio and satellite telecommunications," NOAA said.

It was possible that the geomagnetic storm would disturb some transmission systems in the Northeast, NOAA advised. The strengthening storm could rate at Kp 5 or Kp 6 — on a scale that goes from Kp 5 to Kp 9 — with possible effects including power grid fluctuations, transformer damage and voltage alarms. Periods of Kp 7 were also possible, necessitating voltage corrections or triggering false alarms on some protection devices, according to NOAA.

Kp is a measure based on the K index, which calculates data from geomagnetic observatories, most of which are in North America, NOAA said. The Kp scale summarizes the global level of geomagnetic activity.

The Ontario Independent Electricity System Operator was watching the storm, spokeswoman Alexandra Campbell said. The system operator has monitoring equipment in place that measures geomagnetic-induced currents on the power system. If current levels were affected IESO would notify neighboring provincial utilities so they could help shoulder demand.

Hydro One, a transmission and distribution company in Ontario, was also monitoring solar activity, spokeswoman Danielle Gauvin said. Geomagnetic activity is expected to peak in 2011 and 2012, she said. Ontario is home to a lot of granite, a material that relays geomagnetic energy, she added.

The New York Independent System Operator has measures in place that are triggered if a geomagnetic storm reaches Kp 7 level, according to its operations manual. The system operator would reduce normal limits on transmission lines and bring transformers to 90% of the normal rating where appropriate, and request that generators adjust "machine excitation" to protect against voltage swings, among other measures. Also, transmission owners in NYISO would restore out-of-service transmission facilities where possible and avoid taking long lines out of service, the manual states.

— Jason Fordney, T.L. Hamilton

Experts advise expanded use of securitization by utilities *... from page 1*

would ask the Public Service Commission for permission to securitize roughly $200 million associated with its now-suspended Little Gypsy-3 repowering project. The bonds would be tied to a retail rate rider whose proceeds over 10 years would be committed to paying off bondholders.

That marks what is believed to be the first use of securitization for a terminated power project, but Joseph Fichera, CEO at Saber Partners, a New York City-based financial advisory firm, said Entergy's plan is really just another use of ROC bonds to recover stranded costs. Securitization should be used much more broadly, he said, and he cited coal-unit environmental improvements, renewable energy, smart meters, and nuclear project cost overruns as examples.

Securitization is "a powerful financing tool that can lower costs for ratepayers without harming [utility] shareholders," Fichera said. Establishing special purpose entities to issue bonds and paying them off using dedicated rate riders enables utilities to make needed investments without issuing bonds of their own, he said.

Robert Reger, a partner in New York City law firm Morgan Lewis' business and finance practice, agreed that securitization is underutilized. "You could securitize almost anything if you made the case" that it benefits ratepayers and does not unduly harm the utility, he said.

One possible use, Reger said, would be issuing ROC bonds to enable a utility to recover extra costs of new solar generating capacity. Regulators might permit the utility to finance a portion of a big solar project with its own funds, and the rest through securitization bonds. That, he said, would reduce the project's total cost, and cut the cost to ratepayers of adding renewables to a utility's portfolio.

Securitization "lends itself to a wide variety of uses," but typically requires support from utilities, regulators and other interested parties — plus state legislators to enact the law needed to permit the sale of securitization bonds, said Terry Friddle, co-founder and principal at Charlotte-based Pathfinder Capital Advisors, an investment bank and financial advisory group.

Louisiana breaks new ground

That broad support coalesced in Louisiana, which at Entergy's urging last year enacted Act 988. That law expanded the state's 2005 and 2006 securitization laws to permit the use of ROC bonds to recover costs of canceled power projects, as well as other investments exceeding $350 million that the PSC determines would be appropriate for ROC bonds.

Entergy Louisiana, which already has used securitization to recover costs of four hurricanes, plans to seek PSC approval to recover the $200 million in Little Gypsy-related costs if, as expected, the commission approves the utility's plan to cancel it, said Karen Freese, assistant general counsel at Entergy Services, a sister company.

Securitizing Little Gypsy costs would result in "substantial" savings for ratepayers because the likely 4% to 5% interest rate on the AAA-rated securitization bonds would be considerably less than the utility's general cost of capital, Freese said.

The PSC in November 2007 approved Entergy's $1.76 billion plan to convert a natural gas-fired peaking unit in Montz, Louisiana, to a 535-MW, petroleum coke and coal-fired facility. By early 2009, however, the utility determined that a weak economy, lower natural gas prices and potential federal CO_2 legislation had undermined the economic rationale for the project, and asked the PSC to let it suspend project work for three years.

The PSC agreed in May 2009. Five months later Entergy asked that the project be permanently canceled, and that the PSC permit recovery of Little Gypsy costs over five years with a rate hike (*EUW*, 2 Nov '09; 18 May '09, 12).

Freese said Entergy's new plan to securitize Little Gypsy costs with 10-year bonds should cost much less, but it is too soon to know what the details of the rate rider will be.

Securitization would be a "win-win scenario" in a case such as Entergy/Little Gypsy, said Bruce Gebhardt, partner at Pathfinder, which has advised the PSC in past securitizations for Entergy storm costs. With securitization, Entergy would not earn a return on Little Gypsy costs, and the cost to ratepayers would be minimized.

Other uses for securitization are possible, Gebhardt said. For example, if a new nuclear unit were to run several billion dollars over budget, regulators might determine it would be better to remove all or most of the overruns from rate base and permit recovery with securitized bonds. That way, a utility would earn its normal ROE on the originally expected cost of the nuclear project, but not on cost overruns.

Louisiana PSC Chairman Jimmy Field supports the securitization approach because it permits utilities to recover prudently incurred costs while at the same time minimizing the cost to ratepayers.

"It's never pleasant for a regulator to have to allow a utility to recover the costs of a canceled project" that ratepayers will never see a benefit from, Field said, referring to Entergy and Little Gypsy. He said, however, that the repowering project had been previously approved by the PSC, and changing conditions made proceeding with the project unwise.

"Then the question becomes, 'How do you let them recover their costs?" Securitization may well be the best answer, he said.

— Housley Carr

EPA greenhouse gas program would be axed by House spending bill *... from page 2*

the Advanced Research Projects Agency-Energy, $400 million.

Energy Secretary Steven Chu said Wednesday that the plan by House Republicans to cut DOE's budget starting next month would have a "severe adverse impact" on various DOE operations, including nuclear security and scientific research.

"It would compromise a lot of what we need to do in our nuclear security. It would compromise a lot of what we need to do in winning the future in getting things going," Chu said after a Senate hearing on DOE's fiscal 2012 budget request.

Cuts to DOE's Office of Science, which funds research at the agency's national laboratories, would likely lead to "real, severe impact" at the labs, including layoffs or furloughs, Chu said.

The CR also cut $390 million in funding for the Low Income Home Energy Assistance Program, which provides heating assistance to homeowners, compared with Obama's 2011 budget request. In 2010, the program received $590 million.

During a week of debate on the bill House members voted on scores of amendments, but accepted only a few changes to the bill. They included a measure by Kansas Republican Representative Mike Pompeo, to strip $8.4 million from EPA and block the agency from developing a registry measuring greenhouse gas emissions.

— Keith Chu

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