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Electric Utility Week

May 23, 2011

Taking on the incentive-rate question, FERC asks for advice on whether to make changes

The Federal Energy Regulatory Commission's policy for giving rate incentives to transmission projects may or may not need changing, commissioners said last week, but it is time for a serious look at the matter. They issued a formal notice of inquiry, which may or may not result in a proposed rule.

Critics and some commissioners themselves have expressed frustration over the last few years about what some have called "FERC candy," incentive rate adders for projects they do not believe merit them. But at their monthly meeting last week, commissioners took a measured, almost cautious, tone in talking about the review they were undertaking in the NOI (Docket No. RM11-26).

Commissioners "went out of their way to say they're not throwing" the existing policy away, observed Christine Tezak, senior energy and environmental policy analyst for the consultancy firm Robert W. Baird.

The commission is not assuming that anything is broken in the policy, she said. Rather, it is acknowledging that energy associations, state utility commissions, utilities and even members of FERC have

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Customers will have to pay to avoid meter concerns in Maine; could set a precedent

Making a policy call that was praised by utility Central Maine Power and a customer group concerned about health effects from advanced meters, Maine regulators said the utility should allow customers to decline the use of advanced meters, for a price.

The Public Utilities Commission ruling came last week after a barrage of complaints by a small number of CMP customers, challenging the safety and health effects of radio frequencies from advanced meters and the wireless communication network that is part of CMP's smart grid project.

A similar proposal allowing customers to opt out of the advanced metering network is pending in California, where Pacific Gas and Electric's filing is being considered by that state's PUC.

Thus, with two utilities at opposite ends of the country facing customers with health concerns, the smart grid community now may be watching for a couple of things: how many customers will be willing to pay some hefty charges for the ability to avoid radio frequencies associated with advanced meters, and whether the health concerns seen in the two states will spread

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PJM capacity prices rise surprisingly high, prompting speculation about west-east issues

The PJM Interconnection's basic capacity price soared 354% to clear at $125.99/MW-day in the regional transmission organization's capacity auction for 2014/2015, surprising power market analysts and prompting much speculation about the cause.

A year ago, in the auction for 2013/2014, the capacity price cleared at $27.73/MW-day. The basic RTO price is for the least dense or least constrained areas. Other areas clear higher. Altogether the auction cleared 149,974 MW of capacity, which represents a reserve margin of slightly less than 20%. The total was 2,769 MW less than last year's auction.

Also surprising analysts when the new results were announced May 13 was the closeness of pricing in PJM East and PJM West. Analysts had predicted a good deal of separation.

"The auction result was an exact opposite of our expectations," said a May 16 report from Macquarie Equities Research, which had estimated that the RTO price would clear at $40. Another analyst, Barclays Capital, had predicted $50.

"We are still surprised about the strength of RTO pricing,"

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INSIDE THIS ISSUE

EV charging issues to challenge utilities, Accenture says, with education a big need

A majority of consumers said they would consider buying a plug-in electric vehicle for their next vehicle, but consumer preferences about charging EVs will challenge utilities and companies focusing on EV-charging infrastructure, Accenture said last week.

The consulting firm conducted a study of more than 7,000 people in 13 countries, and found that 60% would consider buying a PEV for their next vehicle, and 68% would do so within the next three years. Respondents in China were by far the most enthusiastic, with 96% probably or certainly considering buying a PEV in the next three years.

While some models of EVs are more expensive than conventional vehicles, which has been cited as a potential factor limiting EV acceptance, Accenture found that other factors, such as the availability of charging points and the driving range on a single charge, are more important to consumers in its study.

Fifty-one percent of consumers would buy a PEV if the total operating cost was lower than a conventional vehicle, while 63% cited charging point availability and 53% driving range as a factor.

Among those willing to consider buying a PEV, the fuel source of their electricity would play a role, with 80% wanting to know the source of electricity used, and 45% saying that the fuel source would have an impact on their decision to buy, Accenture said.

Consumer preferences for charging PEVs — which differ from plug-in hybrid EVs in that they have no internal combustion engine to extend driving range on a single battery charge — could challenge utilities and others because 67% of the respondents are not willing to let companies limit when they can charge the vehicles, Accenture said.

Automakers, EV advocates and utilities often point to the ability to charge vehicles during the night, or whenever they are plugged in, with the ability to charge at certain periods to manage demand on the power grid as a key factor in EV acceptance. But Accenture found that 55% of respondents would want to plug in their vehicles when they need to charge the battery, not whenever they park the vehicles. That would result in less predictable charging patterns, reduce demand for public-charging infrastructure and limit the ability of utilities to manage grid congestion, Accenture said.

The survey results show that consumers do not have much hands-on experience with EVs, said Wade Malcolm, technology director for Accenture's smart grid services segment. Utilities will need to be more actively involved in addressing consumer preferences about charging, or adjust their infrastructure planning and grid operations forecasts to meet consumers' charging needs, Malcolm said in an interview.

Utilities should ensure that any PEV pilot projects or initial customer experiences with electric vehicles focus on the consumer needs and not just the technology issues and making consumers adjust to utility preferences, Malcolm said.

The head of the Electric Drive Transportation Association said the Accenture survey shows that the key to EV adoption is improving consumer education, and that EDTA has a website dedicated to that, at www.goelectricdrive.com. EDTA and others are working to make sure consumers have everything they need to know about owning an EV and their charging options, said the organization's president, Brian Wynne.

EDTA says overnight charging will be preferred

Most consumers who charge their vehicles at home are expected to do so overnight, and PEVs can be charged from a standard household outlet, Wynne said.

In addition, while customer experience may be lacking at

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Correction

An article May 16 about smart-grid developer Ambient incorrectly described the number of endpoints serviced by nodes, which are communication platforms placed on transformers, in Duke Energy's deployment. The more than 35,000 nodes deployed – not each node, as reported – will service more than 250,000 endpoints.

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MARKETS

New England's capacity market dispute echoes, in part, arguments in PJM market

Less than a month after the Federal Energy Regulatory Commission affirmed its decision to apply the public interest threshold to any challenges to ISO New England's forward capacity market design, it has been accused of violating that very threshold by revising the FCM construct without showing just cause for doing so.

In the same case, FERC has also been presented with some of the same issues it is dealing with in the PJM Interconnection's capacity market dispute, where states and a host of capacity-buyer interests are challenging commission-approved changes to pricing rules for state-sponsored generation.

With respect to the public-interest threshold, utilities NStar Electric and United Illuminating said FERC's April 13 order approving revisions to the way ISO-NE mitigates market power for bids into its FCM auctions "summarily disregarded these safeguards and the heightened review threshold the commission affirmed less than a month ago."

The decision rejected a proposed alternative pricing rule that was meant to guard against uncompetitive auction results and directed the ISO to come up with mitigation measures similar to those of PJM Interconnection and New York Independent System Operator.

"The commission has not merely refined the edges of the FCM settlement construct, but has instead wholly rejected a market-based approach to the pricing and acquisition of capacity in favor of a scheme that establishes an administratively determined supply curve, favors existing resource owners over new entrants and repudiates the good faith efforts of states to remedy capacity deficiencies," NStar and United Illuminating said (Docket No. ER10-787).

NStar and United Illuminating were joined by states and other utilities in the argument that the changes were not backed by substantial record evidence, although most comments did not go so far as to suggest FERC violated its landmark decision to apply the public interest threshold to the related 2006 FCM settlement proceeding.

A number of New England state utility commissions also asked FERC to clarify its order to ensure the changes do not work at cross-purposes to state generation development efforts. In addition, several utilities suggested the approved elimination of a dynamic de-list bid threshold leaves the capacity market without an effective price stabilizer.

The rehearing requests came one day after a variety of market participants and states in PJM Interconnection asked FERC to undo its changes to PJM's minimum-offer price rule, which they claim would make it so that the PJM capacity auction would be the only arena for meeting capacity obligations, instead of allowing load-serving entities to self-supply and states to pursue their generation development initiatives.

In those rehearing requests, market participants also claimed that FERC had not shown that state generation efforts would actually suppress capacity prices, the very possibility that the price rule changes were designed to address.

In the ISO-NE proceeding, the commission declared the agreed-upon FCM settlement construct unjust and unreasonable because market participants did not address its concern about the "hypothetical suppression of prices when new capacity is not needed, while failing to acknowledge its prior approval of [ISO-NE's alternative pricing rule] as a market power mitigation tool," NStar and United Illuminating said.

"The red herring underlying the generation sector's assault on the APR is the unfounded claim that: (1) states are intentionally attempting to suppress prices in the FCM; and (2) state-mandated programs are affecting the FCM," they said. "There is no evidence in support of either proposition."

NStar and United Illuminating went on to suggest that the intention of the FCM design was to clear capacity prices at the natural intersection of supply and demand. "The right to self-supply was enshrined. ... Tugging at a single thread in the fabric, the commission now seeks to impose a radically different construct" on the New England Power Pool participants. "This, however, the commission cannot do."

When the FCM settlement was negotiated, most participants expected that new capacity would be needed within the decade and that the clearing price would sometimes increase to the cost of new entry when a new peaker unit joined the market, NStar and United Illuminating said. The reality has been that the recession has led to a drop in demand and an overabundance of capacity.

The FCM was established in a multiparty settlement that FERC approved in 2006. In that case (Docket No. ER03-563), FERC said the public interest presumption, then known as the *Mobile-Sierra* public interest standard, would be applied to any challenges to the tariff rates, including cases in which the commission itself wanted to revise the tariff.

That decision made its way to the Supreme Court, which ruled that all power rates, regardless of whether they were established under a contract, are subject to the Federal Power Act requirement that they be just and reasonable. But contract rates cannot be changed unless there is a showing that the results are contrary to the public interest. This is commonly referred to as the *Mobile-Sierra* public-interest presumption as redefined by the Supreme Court in 2008.

On remand, FERC in March said that it had the discretion to apply the public interest threshold to the FCM settlement because the auctions "share with freely negotiated contracts certain market-based features that tend to assure just and reasonable rates." The commission more recently rejected a pipeline's attempt to apply the public interest threshold to rates agreed to in a settlement with the pipeline's customers. It said the circumstances of that settlement did not warrant the higher threshold.

FERC in April rejected and approved a variety of proposed changes to the way the ISO mitigates market power for bids into its FCM auctions. The commission directed the ISO to look at buyer-side mitigation measures of two other regional transmission organizations, including PJM, and create something similar.

It also ruled that out-of-market offers that had cleared in the first

three auctions — also known as historical OOM resources — should not trigger the existing capacity pricing rule in future auctions. OOM resources are generation units built under state-funded initiatives. Because these power plants have contracts outside of the ISO market that cover some or all of their costs, they have until now been able to offer into the FCM auction at below-market rates.

Although the commission did not spare state resources from the minimum price rules, it said states and individual generators could seek a FERC exemption through a Federal Power Act Section 206 filing.

The order did away with a dynamic de-list bid threshold of 0.8 times the cost of new entry and replaced it with a fixed $1/kW-month threshold. A de-list bid is a request by a generator to not offer capacity in the market for a coming auction.

This decision "effectively eliminated the primary market price stabilizer ... and did not replace it with an alternative means of stabilizing prices," said the joint rehearing request of subsidiaries of PSEG and NRG Energy.

"Without a price stabilization feature, the FCM construct is likely to return to extremely low prices, making it mathematically impossible for an investor to earn an acceptable return, even over the long-term," the companies said. This will result in "an inefficient boom/bust capacity cycle that will increase costs to consumers and decrease reliability in New England."

Also arguing that FERC erred in reducing the dynamic de-list bid threshold were New England Power Generators Association and NextEra Energy Resources. When auction results indicate an oversupply of capacity, "such as we have now, reflecting substantial uneconomic out-of-market entry, the clearing price will, absent a higher price floor, essentially be capped at $1/kW-month," they explained. "If supplies eventually tighten (assuming out-of-market activity is fully mitigated), prices will spike. The forward capacity market thus will have lost the price stability that the commission originally sought to create."

Prior to the April order on changes to the FCM mitigation regime, several New England states asked FERC to direct the ISO to exempt state-policy driven resources from minimum bid requirements. They sought something similar to the exemptions the commission has since allowed PJM to give to renewable resources under its MOPR.

On rehearing, states and others want the commission to clarify that a categorical exemption from the minimum offer requirements for new and existing state-mandated resources would be just and reasonable, leaving ISO-NE stakeholders free to pursue such an option.

"This exemption is necessary to ensure that renewable and cost-effective energy efficiency resources receive the same treatment in New England, under the ISO-NE tariff, as they do in the Mid-Atlantic states under the PJM tariff," said a joint filing by the New England Conference of Public Utility Commissioners and commissions for the states of Connecticut, Vermont, Maine and New Hampshire. The May 13 rehearing request also included Northeast Utilities, ratepayer advocate offices in Connecticut and Vermont and the Massachusetts attorney general.

The commission needs to clarify that it did not intend to "force state commissions and other entities to file Section 206 complaints in order to obtain mitigation exemptions," said the joint rehearing request. "Having acknowledged that mitigation waivers may be appropriate in certain circumstances (including where state policies promote development of renewable resources), it was arbitrary to conclude that states commissions' only option was what they already had — to file a complaint under Section 206 alleging that the tariff is unjust and unreasonable."

One alternative may be to allow states to seek a FERC declaratory order "prior to initiating the administrative process necessary to solicit new resources," they said.

The states and others also asked the commission to list the criteria it would use to weigh state exemption requests. In particular, FERC should consider a waiver request for a new resource built to meet specific state policy objectives such as "developing resources using innovative technologies or to meet particular reliability needs." They said the order did not adequately counter their arguments for exempting renewables from the mitigation rules.

In a separate rehearing petition, the Massachusetts Department of Public Utilities urged FERC to outline the exemption criteria.

If the new pricing regime is not implemented before the next FCM auction, what mitigation measures would apply to out-of-market offers in the interim? asked NEPGA and NextEra.

Noting that the order directed ISO-NE to develop an offer-floor mitigation approach, NextEra and NEPGA suggested this same regime could be applied to OOM until the new measures are in place. "This will mean that interim OOM will need to be treated as new resources" and be required to demonstrate that the bids are economic on a market basis. "Unless fixed, these errors unfortunately will leave the ISO-NE capacity markets in distress for many years to come," NEPGA and NextEra said.

They also reiterated previous arguments that all OOM bids, whether from historical resources or not, should be subject to the mitigation.

— Esther Whieldon

Rebuffed by FERC ruling, New Jersey BPU plans to look again at how to attract new generation

In the wake of a recent federal regulatory ruling that dealt a blow to recently passed legislation in the state, the New Jersey Board of Public Utilities plans to open in early summer a proceeding to investigate the prospects for developing new generation in the state, Greg Reinert, a BPU spokesman, said last week.

"The investigation will look at every aspect of why new generation is not being built in New Jersey, including who, if anyone, may be standing in the way of new generation being built," Reinert said.

The BPU has not determined what form the proceeding will take, but it will include a technical conference and a stakeholders meeting, Reinert said.

State lawmakers spearheaded an effort to get new generation built

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NEWS BRIEFS

Toshiba intends to buy energy metering manufacturer **Landis+Gyr** for $2.3 billion, to capitalize on utility smart grid projects around the globe. Switzerland-based Landis+Gyr has operations in more than 30 countries and more than 8,000 customers for meters and associated equipment. Advanced meter installations for smart grid projects are a major part of its business. The deal is designed to create a new segment within Toshiba targeting the smart grid market, it said. The deal would create a new product portfolio among the Japanese company's numerous business interests in energy and technology, adding Landis+Gyr's brand and advanced metering expertise. Toshiba has 203,000 employees and annual revenue of $77 billion. Toshiba intends to retain the Landis+Gyr brand and has no plans for job cuts or restructuring as a result of the deal, the companies said. Besides Landis+Gyr, other major firms in the business of manufacturing advanced meters include **ABB**, **Itron**, **GE**, **Sensus** and **Elster**. Dozens of other companies, along with the meter manufacturers themselves, are in the meter data management space to aid utility smart grid projects.

... The **Federal Energy Regulatory Commission** decided to rehear a **California Independent System Operator** capacity procurement issue. In a March 17 order, FERC had agreed with Cal-ISO's plan to implement its capacity procurement mechanism without a sunset date. But FERC at the same time called for a technical conference on compensation and other CPM elements that might not be just and reasonable (Docket No. ER11-2256). Cal-ISO said in its April 18 request for rehearing that the law requires FERC to evaluate CPM, the total cost of compensation under Cal-ISO program, cost recovery and other issues that may come up in the technical conference. "That record will not be complete until the technical conference and subsequent briefing are concluded. Consequently, the March 17 order errs in deciding issues related to the quantity and term of CPM designations divorced from and without the benefit of the full record and issues to be developed relating to price, compensation methodologies and the level of total compensation," Cal-ISO argued. **Independent Energy Producers Association** also had asked for rehearing, disputing FERC's approval of "partial-unit capacity" and other provisions

... Indiana Governor Mitch Daniels signed comprehensive energy legislation (S.B. 251) allowing CO2 pipeline developers to use eminent domain to condemn property for projects (*see related story, this issue*). Strongly supported by utilities, the legislation could help enable Texas-based **Denbury Resources** to construct a pipeline carrying CO2 from several Midwestern clean coal plants to the Gulf Coast for use in enhanced oil extraction. Opponents objected to giving a company the right to condemn private property. Similar legislation passed the Kentucky General Assembly earlier this year. The Indiana bill includes an automatic customer bill "tracker" for rate recovery of federally mandated costs, including for environmental improvements at coal plants, and financial incentives to aid **Indiana Michigan Power**'s planned uprate at its 2,100-MW Donald C. Cook nuclear plant in Michigan. It also features a voluntary clean energy standard that urges — but does not require — utilities to obtain at least 10% of their power from renewable energy by 2025. The law takes effect July 1.

... At a time when some states are backing away from efforts to cut greenhouse gas emissions, Vermont is stepping up its focus on the issue. Vermont Governor Peter Shumlin, a Democrat, formed the **Climate Cabinet**, a group of senior administration officials that will help direct state efforts to cut carbon dioxide emissions and reliance on fossil fuels. The group will be led by Deb Markowitz, Vermont Secretary of the Agency of Natural Resources. Among its duties, the group will try to foster in-state renewable and sustainable energy sources, with an eye toward lowering energy costs while boosting the "green" economy. "At a time when few if any states are focusing on climate change, Vermont is committed to doing everything possible to mitigate the threats and impacts," Shumlin said. Besides nuclear and hydroelectric resources, Vermont has natural gas-fired and oil-fired power plants.

... Expect an above-normal Atlantic hurricane season, with 12 to 18 named storms and six to 10 hurricanes, of which three to six will strengthen into Category 3 or above storms, the **National Oceanic and Atmospheric Administration** warned Thursday. NOAA's forecast is a 65% chance of an above-normal season, 25% chance of a near-normal season and only a 10% chance of below-normal tropical activity. The Atlantic hurricane season runs from June through November. NOAA based its outlook on the "tropical multi-decadal signal," which has contributed to above-normal tropical storm activity since 1995, plus continued above-average surface temperatures in the tropical Atlantic Ocean and Caribbean Sea and predictions current La Nina will give way to neutral conditions by summer. In addition, water temperatures in two parts of the Atlantic Ocean thus far in 2011 indicate that eastern Canada can expect a more active-than-normal hurricane season this year, a Canadian government official said Thursday. While **Environment Canada** largely takes its lead from NOAA on storm numbers for the wider Atlantic Basin, the agency focuses on water temperatures off the province of Newfoundland and Labrador and in the Atlantic between Brazil and Africa to provide more detailed forecasts for eastern Canada, the agency's Chris Fogarty said in a briefing.

... Ohio's consumer advocate wants **American Electric Power** to trim rates more than the company proposed to comply with to an **Ohio Supreme Court** ruling. The court ruled April 19 that the **Public Utilities Commission** had "acted unlawfully" in approving portions of AEP's three-year electric security plan in 2009, which included provider of last resort charges and certain environmental costs. The PUC ordered AEP to stop collecting millions of dollars in charges until the company submitted new tariffs reflecting the court order (*EUW*, 9 May, 27). On May 19, the **Ohio Office of Consumers' Counsel** and **Ohio Partners for Affordable Energy** asked the PUC to reject the revised rates. They argued that AEP customers should not have to pay an extra $54 million in "unlawful rates," and that the PUC should consider assessing a penalty against the utility.

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as a means to lower electricity rates and replace older generation, and in January passed a law subsidizing the construction of 2,000 MW.

The state's efforts to get the generation built faced a setback in mid-April when the Federal Energy Regulatory Commission authorized a change in the PJM Interconnection's minimum offer price rule that removed an exemption for state-sponsored projects. That exemption would have allowed three projects selected by the BPU to receive long-term contracts with the state's utilities to bid in and clear PJM's capacity auction. Now projects must bid in at 90% of their cost, making it less sure that they will clear. Hess, NRG Energy and Competitive Power Ventures were selected in March and signed contracts with utilities in late April.

Industry observers have been watching the BPU for signs of what it plans to do since Lee Solomon, president of the BPU, said FERC's decision did not address the failure of the PJM market to deliver new capacity in New Jersey.

Solomon said in April there were options available to pursue new generation that were outside of FERC's jurisdiction, although he did not specify what those options were. "At this time it appears that we will be forced to pursue those options. I do not believe that New Jersey forfeited its sovereignty when PJM became" the regional transmission organization, he said last month.

The issue of the impending generation proceeding was raised at the May 16 board meeting in the context of a discussion over the BPU's decision to intervene at FERC in the New York Independent System Operator's April 29 request for an interconnection agreement for a merchant transmission line from New Jersey to New York. The line would allow up to 660 MW to be shipped from New Jersey to New York, Reinert said. The line would only allow power to flow in one direction, he said.

"Studies show that up to 3,000 MW of new generation in New Jersey would be beneficial. With the transmission line to New York it would increase to 3,660 MW," Reinert said.

Adding to the state's concerns is the impending retirement in 2019 of the 645-MW Oyster Creek nuclear station, the state said in a filing at FERC asking for a rehearing of its April 12 decision approving changes to the minimum offer price rule.

The result of FERC's ruling is to subject New Jersey residents to brownouts or blackouts in the near future, Paula Dow, New Jersey's attorney general, said in the May 12 filing.

The changes in the minimum offer price rule represent "a significant step backward, essentially tightening the grip existing incumbent generators hold on blocking new entrants from building new sources of generation," the filing said.

In PJM's most recent capacity auction, concluded last week, the Northern New Jersey area (PS North) in PJM had a clearing price of $225/MW-day, down $20 from last year, but substantially higher than the PJM capacity clearing price of $125.99/MW-day (*see story, page 1*).

"The Northern New Jersey price should make New Jersey politicians more inclined to move forward with their efforts to build new generation," an analyst who asked not to be identified, said.

"The results of the RPM [reliability pricing model] auction are supportive of our position that New Jersey, and especially Northern New Jersey, is capacity constrained. Less than 75 MW of new generation capacity cleared in the EMAAC region in the 2014-2015 auction. The PS Northern zone was the only area in PJM that had a binding constraint, and the resulting price of $225/MW-day reflects that constrained condition. New Jersey continues to pay a premium price for capacity, without noteworthy additional generation. Furthermore, this year's slightly lower auction clearing price [for northern New Jersey] is due to public efforts to build new in-state generation," Reinert said.

In other action, the BPU on May 16 began accepting applications for offshore wind projects to participate in the state's program to support the construction of 1,100 MW.

Applications will be accepted through June 14 for projects proposed in state waters. No date has been set for receiving applications for projects proposed in federal waters, Reinert said.

The program was established by legislation signed into law last summer by Governor Chris Christie. The program requires utilities to buy offshore wind renewable energy certificates to support projects.

The BPU adopted a regulatory framework for the program in February and developers were poised to apply once the application window opened.

Fishermen's Energy has been waiting for the application period to open so it can begin construction of a 25-MW demonstration project that it expects to have online by September 2012.

The BPU will have 180 days to approve or deny an application.

— Mary Powers

Maryland PSC chairman decries FERC ruling on PJM market, saying it's impossible to plan

The Federal Energy Regulatory Commission's decision to eliminate an exemption for state policy decisions on generation has left Maryland in a tough spot. "It makes it impossible for us to plan or to implement policies," Public Service Commission Chairman Douglas Nazarian said in an interview.

While the state and others have asked FERC to reconsider its April 12 decision to eliminate the state exemption from the PJM Interconnection's minimum offer price rule, Nazarian does not expect FERC to act, but instead "go into a long holding pattern."

"FERC has made a commitment to these market constructs that favor those who own generation. This ruling confirms that," Nazarian said.

The change leaves states with little choice or flexibility to control their own destiny with regard to generation, he said. "The decision clearly exalts the overriding importance of the markets over state policy."

The change in the policy was made after a New Jersey law required the state to subsidize the construction of 2,000 MW and Maryland, worried that power supplies could be limited in Maryland by 2015, issued a draft request for proposals for up to 1,800 MW from new plants.

Under rules in place at the time, new generation could be bid into PJM's capacity auction at zero cost, which would guarantee

they would clear. Now the projects must be bid in at 90% of the cost of new entry.

The decision makes it much more difficult for projects to displace existing generation in PJM's capacity auction, Nazarian said. "This ruling benefits the existing generation fleet," he said.

As a result, a lot less generation will be built anytime soon, Nazarian said. "The whole construct of the market as it now exists is illusory," he said. In theory the reliability pricing model would send a signal to the market for the need for more investment, and the risk would be shifted off ratepayers. Instead, the market is not investing in new generation and existing generation owners are making unregulated profits without taking any risk, Nazarian said. "There is no competition at the generation level."

The decision also leaves states with less ability to plan and implement policies, especially for problems they may anticipate coming down the road, Nazarian said. "For example, new Environmental Protection Agency rules for emissions will increase the cost of running coal plants. Owners of those plants may decide to retire them rather than comply with the regulations. They only need to give 90 days notice. We will hear about it too late do anything, I fear," Nazarian said.

Other events, such as a faster economic recovery or unexpected increases in natural gas prices could leave the state in a position without enough committed resources, Nazarian said.

Events specific to Maryland, such as the reopening of a closed steel mill or military base realignment could increase demand. "We're left to deal with issues with blunt tools," Nazarian said.

A state is no longer able to make a policy decision to add cleaner generation, Nazarian said. Renewable projects are exempt from the MOPR, but they cannot be built on a scale to replace coal, he said. "This ruling has made reducing carbon harder. Inefficient coal-fired plants cannot be replaced with something new," he said. The MOPR rule only applies to natural gas-fired plants.

The one tool that states have left is to increase demand response, energy efficiency and conservation, but there have been efforts to change the rules on demand response to make it harder to participate, Nazarian said.

The state is left with two options: to re-regulate, which the state Legislature rejected two years ago, or to push for a fundamental change to the Federal Power Act. "It's something we're starting to look at. It would be a heavy lift," Nazarian said.

The bigger question is how to manage supply and demand in a restructured state, Nazarian said. "We have to figure out what to do," he said.

Looking back with 20/20 hindsight, "It was a bad decision to restructure," Nazarian said.

— Mary Powers

Georgia co-op rebuts complainants' claims, says customers just trying to rehash dispute

An electricity cooperative in Georgia and its affiliates have asked the Federal Energy Regulatory Commission to dismiss a complaint by two power customers that claims the companies violated the commission's rules on cross-subsidization, market manipulation and market-based rate reporting.

The allegations misinterpret the commission's rules and point to regulations that came into effect after the contracts in question, Cobb Electric Membership Corp. and the other parties named in the complaint said.

They called the complaint an "awkward attempt to force fit the allegations into something within the commission's jurisdiction."

Customers Daniel Davis and Mark Hackett, filing as the Cobb Customer Requesters, in April accused Cobb EMC, the for-profit affiliate of Cobb Energy Management, and another affiliate Cooperative Energy Inc., as well as two top cooperative officials, of violating the commission's rules. The customers asked FERC to investigate their claims (Docket No. EL11-38).

In a joint response on May 16, Cobb EMC, its affiliates and the officials named in the complaint said the customers are attempting to "ensnarl the commission in a dispute that has nothing to do with its regulation of the electricity industry in general or, to the extent applicable, of the respondents under the Federal Power Act." The customers are trying to rehash allegations made in a 2007 suit that was settled in 2008 without going to trial, the joint response said.

The companies asked FERC to dismiss CEI as a defendant because the customers recently dropped their allegations against the affiliate. The customers accused CEI of not reporting market-based rate sales to the commission, but earlier this month wrote to FERC saying they realized that quarterly reports had in fact been filed and asking to take back that aspect of the complaint.

Davis and Hackett also claimed that Cobb EMC failed to tell FERC about substantial changes such as financial losses by affiliates of Cobb Energy that may have affected the cooperative's market-based rate authority status. The customers said this violated FERC's market manipulation and market behavior rules.

"To suggest that the commission should have denied market-based rate authority to Cobb EMC based upon financial losses by subsidiaries of Cobb Energy is ridiculous," because Cobb Energy and its affiliates are not subject to FERC jurisdiction, the response said.

While Cobb EMC's wholesale power sales to CEI are under FERC's purview, those transactions were made at the market price, the joint response said. The cooperative also noted that it operates within the geographic footprint of Southern Company. "It is fanciful to think that a tiny utility like Cobb EMC could exercise market power within the vast Southern Company system."

As for cross-subsidization concerns, the allegations refer to the sale of non-power goods and services to Cobb EMC by Cobb Energy at higher than cost. But those contracts predate the March 2008 effective date of FERC's order prohibiting an affiliate of a franchised public utility with captive customers from selling non-power goods and services at a rate greater than the cost of the service or market price, Cobb EMC and the others said.

After those rules went into effect, Cobb EMC and Cobb Energy did not sign any new contracts until Cobb Energy in December 2008 became a wholly owned subsidiary of Cobb EMC and all pre-existing contracts were revised to provide that

Cobb Energy would sell all goods and services at cost.

The joint response also refuted allegations that former Cobb EMC President and CEO Dwight Brown held interlocking positions as treasurer and director of CEI. When CEI learned that it had become a public utility subject to commission regulations, Brown resigned as its director, the response said.

— Esther Whieldon

PJM capacity prices surprisingly high, prompting speculation about west-east issues *... from page 1*

the Macquarie report said.

Power plants have two main sources of revenue: energy production and capacity, Macquarie analyst Angie Storozynski pointed out. Generators receive capacity payments whether they produce power or not, and PJM's annual capacity auction sets the price for those capacity payments. In densely populated regions with fewer power plants, the capacity payments will be larger than they will be in areas where there are fewer constraints. These payments are most important to plants that do not run frequently, such as older coal plants with high costs, Storozynski said.

The unexpected leap in the basic RTO capacity pricing is probably due to fewer west-to-east constraints, said Hugh Wynne, senior research analyst for Sanford C. Bernstein.

Lower estimates of peak demand in this year's auction led to fewer west-to-east constraints on the transmission system, allowing more western-PJM generators to bid into the eastern market, he said. This raised prices in the rest of the RTO region while depressing those in MAAC, the eastern portion of the RTO.

"There is a lot of coal-fired capacity in the west that could not be delivered into the east last year because of constraints, and that would depress prices in the west," Wynne said. "In this auction the capacity was able to be bid into the eastern market to serve load there. The implication is that you had more demand for that capacity and therefore a higher price, while the opposite happened in the east."

PJM assesses the likelihood that certain areas may be constrained in their ability to import capacity to meet peak load because of transmission bottlenecks, forcing load in the area to be met with local capacity resources, said Bernstein's May 16 report. This year, the number of constrained areas identified by PJM before the auction declined, prompting western-PJM generators to bid a higher price.

The areas covered by the auction can be thought of as a target, with the most constrained area, at the bullseye, being what is called the PS North region in northern New Jersey, where there is dense population and few power plants. The auction cleared a capacity price for PS North at $225/MW-day, down about $20 from last year's auction but still clearly much higher than the rest-of-PJM prices.

PS North is within the MAAC region, which cleared at $136.50/MW-day. The broad RTO region covers all areas not encompassed by MAAC, and has the lowest capacity price, $125.99/MW-day.

Analysts were surprised that two other MAAC areas, EMAAC and PEPCO, cleared at the same price that MAAC did, $136.50. Historically these more densely populated areas have had higher capacity prices than the rest of MAAC, and in fact the EMAAC price of $136.50 is a $108.50 drop from last year. The PEPCO price is down $110.64 from a year ago.

UBS Investment Research was similarly taken aback by the auction results.

"In a surprise turn of events, RTO and EMAAC cleared at near comparable levels," UBS's May 16 report said.

Julien Dumoulin-Smith, analyst for UBS Investment Research, said he thinks prices rose because less total capacity was available in this auction.

"You don't get to $125/MW-day [for RTO capacity] without assuming there was a substantial amount of capacity that didn't clear," he said.

Barclays's report said the results' magnitude surprised the market, and are likely to produce some stock volatility in the near term.

Prices between the eastern and western regions of PJM converged this year because of a significant reduction in forecasted load growth through 2014/2015, said Andy Ott, PJM senior vice president of markets. But UBS analysts think the RTO increase also has to do with more aggressive bidding strategies, their report said.

Last year, capacity prices in MAAC cleared at much higher levels because of a decline in transmission imports into that area, and by the increase in the cost a generator would have to incur to enter the market. The difference this year was an increase in demand response and energy-efficiency resources. Those resources made up nearly 68% of the new capacity available and about 10% of the resources clearing the auction, PJM said.

Wind resources cleared in the auction totaled 695.4 MW, while 45.6 MW of solar resources cleared. As both of those resources are intermittent, only a percentage of total capacity is eligible to meet capacity requirements: 13% of wind and 38% of solar resources. Of the total amount of wind and solar capacity that cleared the auction, 5,349.2 MW of wind energy and 120 MW of solar energy are expected to be available during the 2014/2015 planning year.

Demand response, a voluntary, temporary reduction in the use of electricity, cleared an incremental 4,900 MW, more than double what Macquarie analysts had predicted and more than a 50% increase over last year, Ott said.

The increase played a key role in depressing capacity prices, UBS said.

"A substantial uptick in demand response coupled with new generation resources in MAAC more than offset a marginal improvement in bidding strategy [for eastern regions]," UBS said.

Also noteworthy in this year's auction is the fact that few if any generators bid in environmental capital spending, while Macquarie expected the opposite given uncertainty surrounding compliance with the Environmental Protection Agency hazardous air pollutant rule regarding mercury and acid gas emissions. Power generators will likely have to invest money to scrub their plants and make them compliant with regulations, and these generators would incorporate

that investment into their bids, Storozynski said.

"As your cost rises, so should your offer price," she added.

Some analysts are speculating that some coal plants in the region did bid in environmental capital spending, but that those bids did not clear, and as a result a big chunk of coal-fired capacity was taken out of the market, resulting in RTO capacity prices clearing at a higher level. Ultimately it is hard to tell if that is the case because PJM will not provide information detailed enough to see if that is what happened for another six months, Storozynski said.

Even recent and pending mergers of large coal-fired portfolios surprisingly did not yield environmental capital spending bidding from marginal coal-fired generators, Macquarie's report said.

Generators located to the west were more likely seeking to meet basic fixed costs in bidding more aggressively this year, Dumoulin-Smith said. But still others might have made higher bids considering the upcoming EPA regulations, he added.

"Clearly there was a mixture of both," he said.

Wynne dismissed the environmental capital spending notion, saying that generators would know that incorporating those costs would yield an offer too high to clear. But he said it was likely that in the western parts of the RTO there were a significant number of plant retirements by generators that believed they could not afford to upgrade their plants in order to meet the new regulations. Those retirements would have led to less available capacity, and could have boosted the RTO capacity price.

UBS concluded that the results were favorable for PJM western generators while disappointing for PJM east generators. Macquarie said the impact of the auction on both groups of generators is only 0-3% of their earnings before interest, taxation, depreciation and amortization, with the exception of First Energy, which will feel an impact of positive 6%.

— T.L. Hamilton

ENVIRONMENT

Interest in EPA's power plant rules grows, but congressional action still an unknown

Firm steps to relieve electricity sector concerns about the convergence of several power plant pollution rules have yet to be taken on Capitol Hill, but lawmakers are showing a growing interest in the issue and any possible impacts on electric reliability.

Senator Lisa Murkowski of Alaska, senior Republican on the Energy and Natural Resources Committee, called on the Federal Energy Regulatory Commission in a letter last week to disclose any specific actions it has taken to protect the grid should a substantial number of generating units retire rather than meet the Environmental Protection Agency's new emission requirements.

Any collaboration between FERC and EPA on establishing or implementing these rules are "of critical interest to the nation," she said. "I am deeply concerned about the potential impact these rules may have on the reliability and affordability of our nation's electricity supply."

Murkowski's letter to FERC Chairman Jon Wellinghoff echoed the concern expressed the previous week by leaders of the House Energy and Commerce Committee, who asked EPA, FERC and the Department of Energy what kind of collaboration they may have had with respect to impacts of the environmental rules.

EPA, in response to litigation and legal deadlines, has proposed a suite of rules to reduce fossil generation emissions of mercury, sulfur dioxide, nitrogen oxides and greenhouse gases as well as mitigate the environmental impacts of plants' cooling water intake and coal ash waste.

The agency has estimated 10 GW could retire early as a result of requiring power plants to reduce by 91% their emissions of mercury and other air toxics. A final rule is to be issued in November and the power sector will have three years to comply. EPA has said it may grant a one-year extension to sources.

But the utility industry estimates that 50 to 60 GWs will retire rather than undergo the costly retrofits of pollution controls for aging or small coal-fired units.

American Electric Power, the largest coal-fired utility, has won support from the International Brotherhood of Electrical Workers for a legislative proposal circulating on Capitol Hill to have Congress direct EPA to give plants until 2020 to install pollution controls or shut down.

No one has stepped up yet to introduce this or any similar bill. But congressional and industry sources say that variations of the AEP-IBEW draft are under consideration by some Senate offices; details of any alternative approaches were unavailable.

"There is a growing sense that the Congress needs to provide oversight and accountability of these rules," said Matt Dempsey, the Republican spokesman for the Senate Environment and Public Works Committee. "A clear effort is under way given the enormity of these costs."

IBEW is hopeful that its work on the bill proposal will attract support from Democrats friendly with labor.

"That's why we wanted to come out in the open to say we support it," IBEW Utility Department Director Jim Hunter said in an interview last week. "A real hurdle is going to be with the Democrats in the Senate."

Senate Clean Air and Nuclear Safety Subcommittee Chairman Tom Carper, a Delaware Democrat, plans to hold hearings on EPA's regulations. He "supports the agency's efforts to regulate these harmful pollutants," an aide said, and he "is not currently working on any legislation."

As for Murkowski offering a bill, "No decision on that has been made," her spokesman Robert Dillon said.

In the meantime, three high-ranking Republicans have asked EPA to double the length of the comment period for the mercury-air toxics proposed rule. Christine Tezak, senior energy analyst for R.W. Baird, said there is talk that some moderate Democrats may support a longer comment period as well, but they have not gone on record for it.

"If the EPA declines to extend the comment period, the

push for a legislative fix may grow," Tezak said in a brief analysis. "However, a legislative solution is not guaranteed, as the power sector has not been unanimous in opposing this rule."

Duke Energy, which has a current portfolio that is 70% coal, is seeking two more years on the compliance schedule rather than federal legislation to curtail EPA's authority to proceed with these regulations.

"I'm not supportive of Congress trying to change the regulatory authority of the EPA," Duke Chairman, CEO and President Jim Rogers said last week. "I'm not supporting any of the bills that are on the Hill. The only thing I'm asking for in my comments is that we get a little more time to be able to make the decisions [for retiring units] or retrofit the units."

Rogers admitted his company may be in a unique position compared with other large coal-fired utilities. Duke, based in Charlotte, North Carolina, is prepared to retire between 1,400 and 1,600 MW of old coal-fired generation because replacement capacity — two natural gas plants totaling 1,240 MW and two coal units totaling 1,475 MW — will be built by the end of 2012.

"In a sense, we have a head start on the regulations," Rogers said in a media briefing after he spoke at the Deloitte Energy Conference in Washington. "The only part of the regulations that trouble me is to make sure there is enough time."

The Clean Air Act has historically allowed the power sector five years to meet new pollution rules, he said. But EPA, in its March proposed rule, set a three-year time frame for utilities to reduce their emissions of mercury and other air toxics.

"My belief and hope is that EPA will go from three to five years and give us a little more time," Rogers said. "I'm just trying to get the sequence right for when the nuclear [plant] comes on and the new gas plants come on."

Duke's proposed merger with Progress Energy would also help reduce the company's mercury emissions by increasing its natural gas generation. The merged company's generation mix will be 49% or 50% coal, he said.

A dozen large nuclear and natural gas-fueled utilities that formed The Clean Energy Group to lobby for market-based emission caps have recently countered claims that EPA's rules would amount to a "train wreck" for the power sector. The group backs a study by Analysis Group Principal Sue Tierney that disputes reliability would be compromised under the EPA rules effort to reduce power plant emissions.

In a letter to the EPA administrator last week, Tierney noted that this month's forward capacity auction in PJM, the nation's largest power market with 54 million customers in 13 states, showed that there would be "ample electricity supply after EPA air and water rules take effect on or before January 2015."

"Notably, more than 4 GW of new capacity came into the market with this auction, including new generation and new demand-side resources, such as energy efficiency and demand response," Tierney said. "The outcome shows the variety of ways in which market participants are providing efficient responses to power requirements as well as environmental requirements."

Bernstein analyst sees no supply problems from EPA rules; upsides for some companies

At least some on Wall Street are undaunted by the impacts of pending federal environmental regulations, dubbed a "train wreck" by some in the utility industry, citing higher bottom lines for certain energy companies despite increased power prices, according to one power sector analyst.

"I'm not one who believes we're heading toward a train wreck," said Hugh Wynne, a senior research analyst at Sanford C. Bernstein. The need to replace an estimated 54 GW of coal-fired generation over a three-year period is "not particularly daunting," he said.

The Environmental Protection Agency forecasts that only 10 GW of coal will retire early rather than strap on "maximum available control technology" to reduce mercury and air toxics by 2015. But Wynne estimates that the economics of EPA's rule will shutter 54 GW, reducing utility demand for coal by 106 million tons annually while boosting demand for natural gas by 1.2 trillion cubic feet.

The net effect will be higher electricity prices and higher capacity market prices that materially drive up earnings 15% to 30% for many power companies in these markets, he said.

On-peak prices in PJM could rise between $2/MWh and $7/MWh in 2015 as a result of the EPA mercury and air toxics rule for power plants, the analyst said. Companies likely to benefit from such a price increase include Constellation, Exelon, PSEG, PPL, Calpine, Dynegy, GenOn and FirstEnergy, he said.

Retirements of aging, unscrubbed coal units in PJM also could boost capacity prices by as much as $92/MW-day and up to $65/MW-day in the MAAC region, according to Wynne. Integrated utilities most likely to benefit are FirstEnergy, Exelon, Constellation, PPL and PSEG, and merchants GenOn, Dynegy, Calpine and NRG, he said.

Wynne, who spoke last week at an Edison Electric Institute seminar on EPA's pending rules, also said he expects to see new construction of simple-cycle gas turbine or combined-cycle gas plants during the three-year period leading up to the rule's implementation.

In the meantime, there is more excess capacity because of the recession and demand response will also help fill supply needs, he said. And the capacity auction in PJM last week indicated that the loss of capacity due to EPA's regulations "can be accommodated in that market without major interruption," Wynne said.

About 4.1 GW of incrementally new capacity will be available for the 2014-2015 period as a result of the capacity auction that closed May 13, PJM said. PJM identified this new capacity as coming from new generation, capacity upgrades to existing generation resources, new demand resources, upgrades to existing demand resources and new energy efficiency resources.

— Cathy Cash

PJM said a total of 4.1 GW of incrementally new capacity will be available for the 2014-2015 period, based on the capacity auction that closed May 13 *(see story, page 1)*.

"This incrementally new capacity includes new generation capacity resources, capacity upgrades to existing generation

capacity resources, new demand resources, upgrades to existing demand resources and new energy efficiency resources," PJM said.

— *Cathy Cash*

Illinois joins Indiana, Kentucky in approving pipeline bill to transport CO2 to Gulf Coast

Illinois completed a legislative trifecta last week in support of pipelines to transport carbon dioxide from Midwest clean coal plants to the Gulf Coast when the state House of Representatives gave final approval to legislation in the waning days of the General Assembly's spring session.

As written, S.B. 1821 could do several things: Assist plans by Denbury Resources, a Dallas-based independent oil and natural gas company, for a CO2 pipeline tying in two or more plants in Illinois, Indiana or Kentucky; allow for the construction of a 32-mile pipeline as part of the FutureGen 2.0 near zero emissions project in southern Illinois; and aid other developers of CO2 pipelines and/or storage sites in the state.

On May 18, the Democrat-controlled House voted 80-35 in favor of the bill, which overwhelmingly passed the Senate, 50-4, on April 15. The measure now heads to Governor Pat Quinn, a Democrat, for his possible signature.

Two other states — Indiana and Kentucky — already have approved similar CO2 pipeline legislation that enables developers to use eminent domain to condemn private property for the projects. Last week, Indiana Governor Mitch Daniels, a Republican who may be considering a presidential candidacy, signed that state's CO2 pipeline vehicle, S.B. 251 *(see page 5)*.

"I think this is positive because it's the framework of CO2 transportation," Phil Gonet, president of the Illinois Coal Association, said. "It sets up the mechanism for getting CO2 from the source to the site."

Ostensibly, the Illinois bill is needed to boost the $1.3 billion FutureGen 2.0 project in Morgan County. A pipeline would connect an older Ameren Illinois plant to be repowered near Meredosia with a storage site elsewhere in the county.

In remarks on the House floor preceding the vote, State Representative Thomas Holbrook, the bill's co-sponsor, said the legislation "implements requirements for pipelines so we can build pipelines to transport carbon dioxide" from clean coal facilities in Illinois. There was no debate on the bill before the vote.

Denbury lobbied in favor of CO2 pipeline legislation this year in Kentucky, Indiana and Illinois, and the company has signed CO2 off-take agreements with four proposed coal gasification projects in the three states. Tracy Evans, Denbury president and chief operating officer, recently said the approximately 700-mile-long pipeline could cost as much as $1.2 billion (*EUW*, 25 April, 2). None of the four projects — Tenaska's $3.5 billion Taylorville Energy Center in Christian County, Illinois; Power Holdings of Illinois' $2 billion synthetic natural gas plant in Jefferson County, Illinois; Indiana Gasification's $2.2 billion SNG plant in Spencer County; and Erora Group's $2 billion Cash Creek Generation plant in Henderson County, Kentucky — is under construction.

Others are interested in Illinois as a CO2 repository as well, according to Gonet.

He said a company called Willow Grove has identified a couple of CO2 storage sites in the state. Willow Grove, he said, features several joint venture partners including Sequoia Capital, Reservoir Capital and Madrone Capital, the investment arm of the Walton family, which owns Wal-Mart.

"They have no connection with Denbury or FutureGen," he said. If carbon capture technology evolves, Willow Grove wants to be a part of it, he said. Willow Grove officials could not be reached for comment.

A separate bill sponsored by Holbrook, H.B. 680, is pending in a House committee. It would establish the structure for a permitting system for CO2 storage in Illinois. It is unclear if the bill will move before the General Assembly recesses for summer at the end of May.

— *Bob Matyi*

N.J. SREC prices plunge on anticipated oversupply during next compliance year

The value of New Jersey solar renewable energy certificates tumbled over the last few weeks as buyers bid down prices in anticipation of an oversupply of SRECs during the next compliance year.

The fall represents the steepest price movement ever seen for New Jersey SRECs, which are historically the most expensive REC product in the country.

"There has never been enough supply to meet demand. That's why the prices have been about 97% of the cap," said Michael Flett, president of an online SREC auction platform called Flett Exchange, referring to the penalty fee competitive retail suppliers in New Jersey must pay for every MWh they are short of annual targets.

The penalty fee, which is $675 per MWh in 2010-11, essentially caps how much buyers are willing to pay for a SREC.

The supply-demand outlook shifted dramatically with the release of figures showing record-high solar installation.

Market players interpreted the solar capacity numbers to mean that the volume of SRECs created in the 2011-12 compliance year, which begins in June, would outstrip demand for the first time.

This new paradigm led buyers to depress prices for July delivery far below historical levels.

"Utilities figured if there is going to be a glut then let's bid down," said Izzet Bensusan, executive director of Karbone, a brokerage and research firm.

One broker said SRECs for delivery in the upcoming compliance year went from more than $600 to as low as $375 before stabilizing between $450 and $475.

Meanwhile, prices remained stable for SRECs delivered in the current compliance year settling around $655, reflecting tight market conditions.

In April, the New Jersey Board of Public Utilities released a statement that the state's solar capacity surged over the last year. In 2010, the amount of solar capacity installed was greater

than the total amount since the launch of New Jersey's clean energy incentive program in 2001, the release stated.

Installed solar capacity stood at 305 MW at the end of March.

New Jersey's renewable portfolio standard requires competitive retail suppliers to purchase 442,000 SRECs generated in 2011-12, which works out to 368.33 MW of installed solar capacity.

The likelihood of reaching that capacity threshold suddenly appeared likely considering that the rate of newly installed capacity averaged 15 MW per month from September 2010 through March 2011.

New Jersey's solar building boom has hardly been a secret. The state ranks second in the country behind California in terms of installed solar capacity.

But even those working in the solar industry were surprised by the possibility that supply would soon exceed demand.

Part of the reason why is a lack of transparency regarding the project pipeline, said Dwight Reynolds, president of US Solar Energy Systems in Basking Ridge, New Jersey.

New Jersey does not require solar systems to register until they are close to being commissioned, he said.

"The market was spooked," one broker said.

"People are in panic mode," said Roger Xia, general manager at Aston Solar, a New Jersey-based solar developer. "It's similar to a run on the bank if everyone rushes to sell at whatever price they can get."

Looking ahead, analysts are reluctant to predict supply or prices beyond 2012.

It was unclear, they said, whether money will continue pouring into New Jersey for solar projects, or developers will end up pulling back in light of lower SREC prices.

New Jersey has designed a mechanism to adjust demand in the event of a chronic oversupply.

Under a law passed in 2010 by the New Jersey Legislature, solar requirements will automatically increase by 20% each year if the market is oversupplied for three consecutive reporting years, starting in 2012-13, and if the average SREC price paid by compliance entities decreased in the same time period.

— Geoffrey Craig

Federal effort to protect birds from wind turbines reveals conservationist divide

New Interior Department guidelines designed to keep birds from being killed by wind-energy projects are dividing environmentalists, with some of the country's largest green groups joining the wind industry in criticizing the guidelines, while other local conservation organizations say they do not go far enough.

Interior's Fish and Wildlife Service accepted public comments through last Thursday on guidelines for land-based wind projects, as well as another set of recommendations designed to protect eagles from turbine blades. The comments reveal a split between groups that want to maximize protections for birds by imposing mandatory new rules on wind companies, and those who see the development of renewable energy as a paramount goal, and hence are siding with industry in calling for FWS to relax its recommendations.

The guidelines for land-based wind projects outline a five-tiered process that wind-energy companies can use to assess the potential risks to birds and other wildlife at various stages of project development. Although the guidelines are voluntary, FWS says companies that comply with them will largely be shielded from prosecution under bird-protection statutes.

The American Wind Energy Association submitted joint comments with prominent environmental organizations such as the Sierra Club, Defenders of Wildlife, the National Audubon Society and the Union of Concerned Scientists. The groups say the guidelines stray a great deal from the recommendations of a federal advisory committee and expand the scope of project reviews too much, covering too many species of birds, among other things.

"The USFWS missed an opportunity to capitalize on the consensus work of states, NGOs and the industry," said John Anderson, AWEA's director of siting policy. "AWEA strongly urges USFWS to reconsider the draft documents as they currently stand and work closely with stakeholders to achieve a more workable outcome for both wildlife and wind energy."

AWEA also submitted its own comments and technical analyses, on the two FWS documents. The group said FWS's wind-turbine guidelines are likely to be ignored without substantial changes, consigning them to the same fate as an earlier attempt to provide siting guidance.

"Industry will not be able to comply with the guidelines as currently drafted; therefore, they — like the 2003 Interim Siting Guidelines — will remain largely unused," AWEA said. "If that occurs, the conservation benefits of adopting the highly workable program recommended by the FAC would be lost."

AWEA and the large environmental groups said voluntary standards in line with the committee's recommendations would serve the goals of promoting renewable energy to fight climate change, while offering broader protections for wildlife than mandatory standards.

"If the USFWS were to decide to make these guidelines mandatory, the scope of the conservation benefits would have to be limited to species only within the USFWS regulatory jurisdiction" under the Endangered Species Act, Migratory Bird Protection Act and Bald and Golden Eagle Protection Act, the industry-environmentalist coalition said in its joint comments. "Therefore, non-migratory birds, many bat species, and species not listed as federally threatened or endangered would be without protection."

Meanwhile, a separate coalition composed mostly of local groups and some national organizations such as the American Bird Conservancy are telling FWS that the non-binding guidelines do not go far enough. These groups are encouraging the service to pursue a formal rulemaking that would impose mandatory requirements for wind development.

ABC says the need for mandatory rules is illustrated by the wind-energy industry's opposition to even merely voluntary guidelines, as well as FWS's demonstrated reticence to prosecute companies for bird deaths under the Migratory Bird Treaty Act

or the Bald and Golden Eagle Protection Act.

"In addition, mandatory standards will encourage the development of wind energy by providing much greater certainty to wind developers and wind financers about what will be required of wind projects," the coalition said.

In separate comments, Friends of Blackwater Canyon, the Center for Biological Diversity and several other organizations argued that FWS must promulgate new rules under the Migratory Bird Treaty Act, which establishes strict liability for anyone who kills a migratory bird.

The groups argue that failure to promulgate such rules and enforce ongoing violations of the act "may open the service to suit under the Administrative Procedure Act … for having 'consciously and expressly adopted a general policy [that amounts] to an abdication of its statutory responsibilities' and for engaging in a 'pattern of non-enforcement of clear statutory language.'"

An FWS spokeswoman said it was "yet to be determined what kind of rulemaking, if any, would be done."

Kelly Fuller, ABC's wind campaign coordinator, said she was not surprised to see some of the larger environmental groups collaborating with AWEA in pushing for the guidelines to be relaxed.

"Some of the large environmental NGOs have been working very closely with the wind industry for a number of years," she said.

Fuller said the groups pushing for mandatory rules want to enforce strict standards as the wind industry ramps up to avoid future regrets.

"We don't want the wind power story to turn out the same way as the hydropower story, where the harm to wildlife was so serious that we had to spend millions and millions of dollars later to rip out the dams. Let's do it right the first time," she said.

But John Rogers, a senior energy analyst with the Union of Concerned Scientists, questioned that comparison, saying it is more important to promote growth in renewable energy to fight climate change.

"I think the overarching framework for this is climate change and the need to really change how we do energy," he said. "And so my greatest fear is that when we look back, it won't be that we've done it wrong, but that we haven't done enough."

— Nick Juliano

FirstEnergy shareholders reject proposals to require reports on coal ash, coal reliance

FirstEnergy shareholders last week turned back two proposals backed by environmental advocacy groups that requested the Akron, Ohio-based company prepare reports on coal ash and the potential impact of the company's reliance on coal-fired generation.

The coal ash proposal received support from 36% of shareholders voting at the company's annual meeting in Akron on May 17, according to company spokeswoman Tricia Ingraham. The coal reliance report garnered even less support — 31%, she said.

While the meeting was going on, a rally sponsored by the Sierra Club and Ohio Citizen Action was taking place outside. Other groups represented included Citizens Against Coal Ash, which opposes FirstEnergy's Little Blue Run coal ash disposal site in Beaver County, Pennsylvania.

As You Sow, a San Francisco environmental group, and Boston-based Green Century sponsored the unsuccessful shareholder proposals.

Little Blue Run is expected to close in the 2016-2018 time frame. FirstEnergy said earlier this year it plans to open a new 264-acre dry storage landfill in Beaver County by 2016 to accept waste from the nearby 2,490-MW Bruce Mansfield coal plant, the largest generating station in Pennsylvania.

Anthony Alexander, FirstEnergy president and CEO, told shareholders the company has taken steps to improve the environmental performance of its generating fleet. "At our Sammis plant, we completed one of the most challenging air quality control projects in the United States," he said, referring to the 2,233-MW baseload plant near Stratton, Ohio. "And the plant's new environmental controls have already achieved significant reductions in sulfur dioxide and nitrogen oxide emissions."

With completion of the Sammis project and the generation capacity acquired by FirstEnergy in its purchase of Pennsylvania's Allegheny Energy earlier this year, Alexander said more than 85% of his company's coal-fired production will be from scrubbed units.

Still, he added, "new environmental challenges" could lead to FirstEnergy closing some of its smaller, older coal units over the next several years while it increases investments at other units.

The defeated proposals were among more than 60 climate and energy-related shareholder resolutions being voted on this spring at utility annual meetings across the country. That is a record number, according to Ceres, a national network of investors, environmental organizations and other public interest groups (*EUW*, 11 April, 1).

— Bob Matyi

TRANSMISSION

No major new lines needed to meet 33% RPS, says Cal-ISO in new transmission plan

California does not need major additional new transmission projects to support the state's expanded renewable portfolio standard, the California Independent System Operator determined in its 2010-11 transmission plan.

The plan, approved by Cal-ISO's board of governors May 18, includes 33 grid upgrades totaling $1.2 billion, meant to boost reliability and support renewables development. All projects that would be funded by ratepayers also require Public Utilities Commission approval.

Governor Jerry Brown in April signed S.B. 2X, which requires load-serving entities to obtain 33% of power supply from renewable resources by 2020.

"The finding that no major new transmission projects are needing approval by the ISO at this time to support RPS reflects years of effort by the ISO, state agencies, the California

Transmission Planning Group, participants in the Renewable Energy Transmission Initiative and market participants that resulted in the approval and ongoing construction of major transmission projects such as Tehachapi and the Sunrise Powerlink," Cal-ISO Vice President of Market and Infrastructure Development Keith Casey said in a statement.

While finding that no new additional major projects are currently needed, ISO said it will reassess these needs based on renewable development trends.

With one exception, proposed upgrades by Pacific Gas & Electric, Southern California Edison and San Diego Gas & Electric were all approved.

SoCal Ed and the Imperial Irrigation District proposed an upgrade to Path 42, designed to deliver geothermal and solar resources totaling 1,400 MW from the Imperial Valley to ISO's grid.

Spokeswoman Stephanie McCorkle said Cal-ISO in December won permission from the Federal Energy Regulatory Commission to consider proposals from independent developers that address economic and policy needs.

But, McCorkle said, FERC requires Cal-ISO to select reliability-related projects based on the obligation to serve or right of first refusal.

FERC is evaluating requiring removal of the right of first refusal from transmission planning tariffs, under which incumbent transmission owners have a right of first refusal to plan and build new projects within their service territory.

IOUs' sponsorship of 189 projects questioned

Before the ISO approval, PUC President Michael Peevey and memberMike Florio warned that Cal-ISO's focus on IOU-sponsored projects could hinder competition.

Since 2006, Cal-ISO has "expressed support for around 190 projects with an estimated combined value of nearly $7.5 billion. With the exception of the Transbay Cable, all these projects are IOU-sponsored," the regulators said in an April 29 letter to Cal-ISO President and CEO Yakout Mansour.

"This trend will have the effect of strongly discouraging continued efforts by independent transmission developers to pursue projects in California," as the state faces more aggressive requirements for renewable resources, Florio and Peevey said.

Ziad Alaywan, president of Z Global, also questioned Cal-ISO's approach.

While Cal-ISO is required in its tariff with FERC to approve projects that boost reliability, it is also bound by PUC rules to select the lowest-cost projects for ratepayers. Z Global is an engineering and analytics consulting firm.

Alaywan is also a member of the board of directors and COO of transmission developer Tres Amigas, which aims to build a "super station" in New Mexico that would link the nation's eastern and western power grids to enable the delivery of renewables.

Because Cal-ISO did not evaluate proposals from private developers, "you don't know if you are getting the best bang for your buck, and you don't know whether another project could be completed more quickly, than utility-owned projects," said Alaywan, a former Cal-ISO employee.

But Michael Picker, senior adviser to the governor, said Brown endorses Cal-ISO's plan.

Brown will "look to see more diversity in the future of transmission providers competing to build transmission, but it's clear that the rapid pace of new generation moving through land use, permitting and construction approvals tends to steer this transitional plan toward existing utility transmission corridors and toward upgrades, rather than new transmission," Picker said, in an April 18 letter to Cal-ISO's board.

California Energy Commission Chair Robert Weisenmiller also urged approval, saying the upgrades would support 11 large-scale renewable projects that have received federal stimulus funding. Additionally, the Path 42 upgrade is critically needed to access renewable resources in the Imperial Valley, Weisenmiller said in an email.

Collectively, these renewable projects "represent thousands of construction jobs in some of California's most economically distressed areas, billions of dollars of investments and can attract billions of dollars of federal subsidies as long as they can commence construction this summer for the loan guarantee, or this fall, for the cash grant," Weisenmiller said,

As for the plan's implications for the 33% RPS, the CEC chair said the approved upgrades along with the already under construction transmission projects, the Sunrise and the Tehachapi lines, will have enough physical capacity to cover the 33% percent renewable requirement.

But, Weisenmiller said, there is "still substantial uncertainty about which projects will ultimately be developed in terms of stimulus funding and the additional projects in the interconnection queue to say [we] know exactly that these upgrades are sufficient."

— Lisa Weinzimer

FERC approves incentive rate treatment for grid projects, including Atlantic Wind

The Federal Energy Regulatory Commission granted incentive rate treatment last week for a number of proposed transmission projects, including the $5 billion Atlantic Wind Connection being designed to serve the thousands of megawatts of offshore wind farms proposed or envisioned off the East Coast.

The proposed high-voltage direct-current Atlantic Wind Connection is being developed by independent transmission company Trans-Elect, Google, Good Energies and Marubeni. The subsea backbone transmission line would be laid along the coasts of New York, New Jersey, Delaware, Maryland and Virginia (Docket No. EL11-13).

FERC conditioned its approval of the incentives on the project's inclusion at some point in the PJM Interconnection regional transmission expansion plan. Atlantic Wind would receive an overall rate of return on equity of 12.9%, which includes 250 basis points in incentive ROE adders. The company had requested 300 basis points.

Other incentives granted Atlantic Wind include 100% recovery in rate base of the costs of construction work in progress, the opportu-

nity to recover 100% of prudently incurred costs if the project is abandoned or cancelled for reasons outside of the developers' control, and a hypothetical capital structure of 60% equity and 40% debt.

Also on Thursday, FERC approved rate incentives for Desert Southwest's proposed 118-mile, 500-kV line to move wind generation to Southern California (Docket No. EL10-54). The package includes 150-basis-point adders to the project's ROE, 100% of CWIP and abandoned plant cost recovery, and a hypothetical capital structure of 50% equity and 50% debt.

Other projects granted incentive rate treatment include Ameren Services' proposed 331-mile Illinois River and 185-mile Big Muddy River projects (Docket No. EL10-80), subject to the projects being included in the regional transmission plans of the Midwest Independent Transmission System Operator. But FERC denied incentives for Ameren's Spoon River and Wabash River projects without prejudice to their filing a new incentive rate petition for those projects in the future.

The 345-kV Illinois River is proposed to include parts of Missouri, Illinois and Indiana at an estimated cost of $739 million. The Big Muddy River project, also a 345-kV line, would include parts of Illinois and Missouri and cost about $383 million.

The Spoon River Project would consist of a 70-mile 345-kV line in Illinois at a cost of $146 million. The Wabash River Project would extend about 52 miles from Newton, Illinois, to Merom, Indiana. Ameren Services estimated it would cost $110 million.

"Ameren Services has not demonstrated that these four projects that are part of the first phase of "Grand Rivers" are parts of a single overall project or share other characteristics that warrant reviewing the projects as a single project," FERC ruled. Therefore, Ameren needed to demonstrate for each project that there was a nexus between the incentive sought and the investment being made.

The scope and effect of the Illinois Rivers and Big Muddy River projects are "significant as each of these projects is projected to span multiple states and have crossings across the Mississippi River," which adds a level of risk to the projects. Moreover, the Illinois Rivers and Big Muddy River projects represent about 93% and 48%, respectively, of Ameren Services' current net transmission plan of $800 million, FERC explained. But the Spoon River and Wabash River projects have not been shown to face risks and challenges comparable to those associated with the above-mentioned projects, FERC said.

It granted some of the incentives requested for Central Transmission's 345-kV Valley project in Illinois, contingent on inclusion in PJM plans (Docket No. EL11-21).

— Esther Whieldon

Montana landowners, others seek to repeal eminent domain law that helps developer

Pushing back against efforts to export wind power, a group of Montana landowners and politicians are working to repeal an eminent domain law passed during the recent legislative session that cleared the way for major transmission lines in the state.

The group is looking to suspend, and eventually repeal House Bill 198, which allows the state to give permission to any person to acquire a piece of property by eminent domain "for a public use." The previous law was used for more than 100 years by the state's utilities, but last year a state judge ruled that it did not apply to Alberta-based Tonbridge, which is building the Montana Alberta Tie Limited Line.

H.B. 198 was a legislative fix to keep the Tonbridge project on track. Currently one landowner along the route of the $220 million, 215-mile high-voltage line is opposing the line transvering her property. Johan v'ant Hof, CEO of Tonbridge, said in an email that they are still working with the landowner. "We are deeply hopeful that we can avoid court action. We see that as a failure," he said. The line is being built with money from the American Recovery and Reinvestment Act.

Schweitzer, who has been a proponent for exporting the state's wind, asked the Legislature to amend H.B. 198 to sunset 2013 so the Legislature would address landowner concerns more fully next session. The Legislature failed to take up his amendment, and the bill went into effect without Schweitzer's signature.

The petition group will kick off its petition drive June 13, and is seeking to get signatures of about 32,000 registered voters by July 2012 in order to place a referendum to repeal H.B. 198 on the November 2012 ballot. If the group gets a slightly higher number of signatures, the law would actually be suspended until the referendum.

The referendum was the idea of Commissioner John Vincent, a Democrat, who served two terms as speaker of the House.

"I believe H.B. 198 simply creates an unlevel playing field for landowners," he said.

Kate Ory, a spokeswoman for the petition drive, said part of the opposition to the eminent domain bill is lack of adequate compensation.

"Out of state corporations are making a profit on the backs of Montanans who have to give up their properties," Ory said. NorthWestern, headquartered in South Dakota, did not respond to a call seeking comment on the petition group's action.

Almost two dozen state Senators and politicians — about half Republicans and half Democrats — have publicly supported the effort, according to the group.

— Pam Radtke Russell

Utilities decry New Hampshire measure limiting use of eminent domain to system reliability

Public Service Co. of New Hampshire and National Grid are voicing opposition to a bill in New Hampshire that would limit utility eminent domain powers, warning that the legislation, which targets a major power line project, would affect other projects as well.

The bill, H.B. 648, was introduced in February in response to the Northern Pass project, a 180-mile transmission project proposed by Northeast Utilities, NStar and Hydro-Quebec that would deliver 1,200 MW of hydroelectric power from Canada into the New England market.

All but 40 miles of the project in northern New Hampshire would follow rights of way owned by PSNH, an NU subsidiary.

The New Hampshire Senate Judiciary Committee held a public hearing on the bill Thursday. The House of Representatives approved the bill 317-51 March 30. The bill would bar utilities

from using eminent domain for transmission projects unless they were needed for system reliability.

Although Senator Matthew Houde, a Democrat and committee chairman, said the hearing was not about the merits of the Northern Pass project, most of the discussion focused on the proposed transmission line.

About a dozen representatives urged the committee to approve the bill, often arguing that for-profit entities should not be able to use eminent domain for private gain. "This bill is about the property rights of individuals," said Republican Representative Laurence Rappaport, the bill's chief sponsor. Property values along the Northern Pass project have been hurt where eminent domain could be used, he said.

The New Hampshire Constitution was amended in 2006 to bar the use of eminent domain for private development, said Republican Senator Jeanie Forrester, one of the bill's co-sponsors. The bill would clarify the constitutional amendment in state law.

The bill's supporters argued that there is no need for the Northern Pass line, but that the project developers would reap major profits from the it. Also, the line would benefit states like Connecticut and Massachusetts, but not New Hampshire, they said.

Donna Gamashe, PSNH director of government affairs, told the committee that the utility opposed the bill, in part because it would have unintended consequences. For example, New Hampshire has a renewable portfolio standard that climbs to 25% by 2025, Gamashe said. Renewable projects will need transmission lines to deliver power to the grid, but the power will not be needed for reliability reasons.

Also, if eminent domain is strictly barred in New Hampshire, developers may have a more difficult time securing financing for their projects.

PSNH in April tried to address concerns about the project by withdrawing five alternative routes for the proposed line, while keeping a single preferred route, Gamashe said. The company is currently trying to reach agreements with landowners in northern New Hampshire and hopes to quickly have the agreements in place, she said. "We have a good portion of it," she said. "We're pursuing it aggressively."

The use of eminent domain is a last resort to move a project forward and a utility must go through a stringent approval process before it can be built, according to the utility.

A National Grid official told the committee that the bill would restrict transmission development in the state and could limit renewable development. The bill could block lines from being built to serve New Hampshire customers, she said.

The committee decided not to take a vote because of the volume of comments it received on the legislation.

— Ethan Howland

FERC grants California ISO tariff waiver, but requires revision to eliminate confusion

The Federal Energy Regulatory Commission last week granted the California Independent System Operator's latest request for a tariff waiver, allowing the ISO to forgo penalties associated with late meter reads from the state's utilities.

But FERC also found that Cal-ISO's tariff language on the subject is unclear and should be clarified.

FERC directed the ISO to revise its tariff so that meter reading data submitted by scheduling coordinators later than 43 calendar days after the trading date will be subject to penalties.

The issue that prompted Cal-ISO's February 1 request was its payment acceleration initiative to shorten the timelines for settling market transactions in 2009. It said any meter data submitted to the ISO by scheduling coordinators later than 43 days after the trade date would be subject to penalties. But it allowed recalculation settlements based on tardy data, in cases where utilities gave meter reading data to the coordinators.

Several market participants said they did not even know they were violating the tariff.

A group of California retail marketers said utilities would routinely update data after each regular meter reading without regard to settlement deadlines in the ISO tariff, FERC noted in the May 19 order (Docket Nos. ER11-2819, EL11-41).

Cal-ISO determined that parties submitting late meter reading data mistakenly believed that they could do so without penalty, and it asked FERC to waive penalties for the period from November 1, 2009 to February 1, 2011. It noted that since the payment acceleration initiative began in November 2009, some 70 tariff violations by 10 market participants would have prompted penalties of about $1.29 million.

Cal-ISO claimed that its request met FERC's three-factor test for a tariff waiver: it is limited in scope, has no undesirable consequences and benefits customers. FERC agreed, granting the waiver for the time period sought.

But the commission also set a Section 206 investigation into the justness and reasonableness of the tariff section and ordered Cal-ISO to revise it to clearly indicate that late meter data will be subject to penalties. The ISO has 30 days to file the change.

In cases when FERC launches a Section 206 investigation on its own, it must issue a decision within 180 days or provide reasons why it cannot. FERC said it expects to meet its November 18 deadline.

— Tom Tiernan

Taking on the incentive-rate question, FERC asks for advice on making changes *... from page 1*

called for the policy to be reexamined and that it may be a good "time to validate that we're on the right course," she said.

Some of the groups brought up the issue when they commented last September on FERC's proposed rule dealing with transmission planning and cost allocation, Tezak noted. "Every time you have a debate on transmission," the incentive rate policy is almost always also brought up, she said.

The incentive rate adders started after Congress in the Energy Policy Act of 2005 added a new Section 219 to the Federal Power Act requiring FERC to establish incentive rate treatments for transmission facilities that benefit consumers by ensuring reliability and reducing transmission congestion, while

continuing to ensure power rates are just and reasonable.

Rate-of-return adders are frequently given on the basis of such criteria as membership in a regional transmission organization, status as an independent transmission company, unusual project risk and use of advanced technology. The incentives can also include such things as recovery of construction work in progress and recovery of costs if a project is abandoned for reasons outside the developer's control.

(At its meeting last week, FERC granted incentive rate treatments to a handful of grid projects. See story page 14.)

The problem for the commission in applying the congressional directive was that EPAct's language left a lot of room for interpretation, former Chairman Joseph Kelliher said last week.

Speaking at a Deloitte Energy Conference in Washington, Kelliher, who is now executive vice president of federal regulatory affairs for NextEra Energy, recalled that commissioners were sometimes divided over certain incentives orders, "but we agreed that we were dealing with pretty lousy language." The law's wording was "pretty awful" and made it harder for commmissioners to come to an agreement on what to do in specific cases.

"The thing that the commission couldn't agree on, and I'm not sure it agrees on quite yet, is: What is the category of transmission that is important enough to the country to merit higher returns?" Kelliher said. Should it be every kind of investment in the grid? "Is it only technology-related projects that deserve incentives?" Is it a line that is important as a backbone project for a region but not for local customers?

The commissioners on Thursday noted that it has been five years since FERC issued a rule setting its policy on transmission incentives and in that time, the commission has received more than 75 applications for transmission incentives.

In the inquiry, FERC asks "whether we are consistently striking the right balance" between promoting transmission development without giving more incentives than needed to do so or whether FERC "should be going some other way," Commissioner Cheryl LaFleur said in the meeting.

"After five years of these cases, it is appropriate to take a step back and take a look and see where we are going," Commissioner Marc Spitzer said.

As for incentive requests while the inquiry is going on, FERC will continue to evaluate them under its existing policy, in Order 679, Chairman Jon Wellinghoff said, to provide regulatory certainty.

In a press briefing after the meeting, Wellinghoff said he had been convinced by fellow commissioners that the policy exam would be worthwhile, but that he was unsure whether the comments on the NOI will lead to a rulemaking.

Commissioner Philip Moeller in the meeting, and again in a statement attached to the NOI, emphasized his belief that it is critical that the NOI state that any future changes to the policy apply prospectively. "These directives from Congress would be frustrated were this commission to increase regulatory uncertainty by changing long-held investor expectations," he said in the statement.

"As the NOI makes clear, our orders on incentives must balance the interests of consumers and the interests of investors," said Commissioner Marc Spitzer. "To foster investment in needed transmission, we must strike a fair balance between those interests. Striking that balance may result in a higher level of incentives for some projects than in the past and in some instances lower incentives than in the past."

Spitzer suggested, and Wellinghoff agreed, that incentive-rate determinations are sometimes more art than science. "It's been a very difficult and a continually moving target," Wellinghoff said.

Having been among those who asked for a policy review, Commissioner John Norris said his comments before and during the meeting were not meant to be critical of past FERC incentive-rate decisions. "I think the commission got to work right after Congress directed it to do so and got the train headed down the right track."

"There are a number of transmission projects that have been built or are in the process of being built that probably would not be today if it had not been for the actions of this commission for the last five years. But it has been five years," he added.

"This NOI gives us a chance to assess our successes and perhaps mistakes and request input on how we may be able to improve our policies and adapt them to any changes in need, or changes in circumstances, that have occurred over the past five years."

The NOI poses 74 questions, including whether the incentive policies are promoting transmission investment. It also notes that some of the things preventing construction of new lines lie outside of FERC's jurisdiction, and asks how the commission's incentive policies affect those barriers.

Have the incentives granted to projects impacted grid reliability, transmission congestion and/or consumer rates and services? the NOI asks. And it seeks descriptions of any impacts incentives may have had had on electric industry investment patterns.

— Esther Whieldon

GENERATION

BPA takes thermal and wind generation offline 'as last resort' as part of environmental redispatch

The Bonneville Power Administration pulled the trigger twice last week on its environmental redispatch protocol, curtailing thermal and wind generation to accommodate an oversupply of hydroelectric power.

The first-ever curtailment under environmental redispatch began Wednesday at midnight and lasted until 5 a.m., according to a news release issued May 18. It included between 200 MW and 350 MW of wind power that was taken offline "as a last resort" after BPA first brought all coal, gas and other thermal resources down to minimum generation levels needed to maintain grid stability.

Later that day beginning at 11 p.m., BPA again curtailed wind and thermal power until 5 a.m. Thursday. Roughly 1,000 MW of wind totaling about 5,700 MWh was taken offline.

More curtailments could be coming, BPA said in a statement released after the first.

With environmental redispatch, BPA is curtailing thermal

(continued on page 19)

The **Department of Energy** offered **SolarReserve** a $737 million conditional loan guarantee for the company's 110-MW Crescent Dunes Solar Energy Project in Nevada. The project has been permitted for construction on 2,250 acres of public land near Tonopah. The concentrating solar project will use a massive field of mirrors to focus solar energy on a 640-foot tower, where it will heat molten salt to drive steam turbines. The use of molten salt allows the facility to store the energy for up to 10 hours, so power can be generated when the sun is not shining. Santa Monica-based SolarReserve has already obtained a power purchase agreement with **NV Energy**, the state's largest utility, for the electricity the facility generates. This is the 24th loan guarantee DOE has offered, and the seventh for a solar generating facility. The financial terms of the conditional award still must be negotiated before it is finalized. Senate Majority Leader Harry Reid, a Nevada Democrat, praised the award.

... A subsidiary of **Radback Energy** can begin construction of a proposed 634-MW natural gas-fired plant in northern California, the **California Energy Commission** said. The developer, which will build the plant on a nearly 22-acre site in Oakley, has a contract to sell the completed facility to **Pacific Gas & Electric** in 2016. The CEC's decision to issue a construction permit came despite warnings from the **US Fish and Wildlife Service** that the Oakley project would threaten the Lange's Metalmark butterfly, an endangered species, as well as certain sensitive plants on the site. As a condition of approval, the project developer will pay roughly $5,000 a year to breed and release the endangered butterfly species and take actions to mitigate impacts on affected plants. In other action, the CEC approved a construction permit for a unit of **Mitsubishi** subsidiary **Diamond Generating** to build a 200-MW natural gas-fired peaker unit in Livermore. The Mariposa Energy plant will supply power to PG&E and back up intermittent renewable resources, which are increasing in the state. Construction is expected to be complete in July 2014, the CEC said. Power will be sent to the grid through a new 0.7-mile transmission line that will connect to an existing PG&E substation. A new gas pipeline will connect the project site to an existing PG&E gas line.

...Terra-Gen Power completed a 720-MW portion of its planned 1,550-MW Alta Wind Energy Center in California, according to a company spokeswoman, effectively increasing the state's wind power nameplate capacity by 22.7% to 3,897 MW. Located 100 miles north of Los Angeles, the first five phases of the approximately $1.5 billion project were built in 13 months and saw the installation of 290 turbines. The project, which has a power purchase agreement with **Southern California Edison**, stands to receive as much as $450 million in reimbursements from the **US Treasury**'s 1603 cash grant in lieu of tax credits program, which pays developers 30% of the cost of construction once their projects come online. Terra-Gen, which is the renewables affiliate of **ArcLight Capital Partners** and **Global Infrastructure Partners**, financed the project through a series of debt issuance and bank credit facilities. While its next goal is to double the size of the facility, its ultimate aim is a 3,000-MW farm to help meet the growing appetite for renewable generation and renewable energy certificates in California and along the West Coast. In January Terra-Gen sold the first 150-MW phase of the Alta project to **GE Energy Financial Services**, a unit of GE, and **Bankers Commercial Corp.**, a unit of **Union Bank of California**, who then leased the facility back to Terra-Gen. Project I used 100 1.5-MW GE turbines. Alta Projects II-V, totaling 570 MW, cost $1.2 billion and used 190 **Vestas American Wind Technology** 3-MW turbines.

... Funds that **Energy Investors Funds** manages completed the acquisition of the remaining 20% interest in **Calypso Energy Holdings**, a portfolio of 12 projects with a combined capacity of 2,700 MW, from **Cogentrix Energy**, a wholly owned unit of **Goldman Sachs**. Terms of the deal were not disclosed. EIF said funds it manages initially acquired an 80% stake in Calypso Energy Holdings in November 2007. The generating facilities are in 11 states and operate under the terms of long-term power purchase agreements with investment grade counterparties. EIF said it believes the facilities will provide "stable cash flows based on contracted generation with regional differentiation, a diversity of fuel sources, and newer generation technology." San Francisco-based EIF said it now has 100% ownership of six of the 12 projects. The fund says it has "mobilized" more than $4 billion in capital raised in seven funds. In October 2003, the Wall Street investment bank Goldman Sachs bought Cogentrix for $2.4 billion. At the time, Cogentrix owned 26 facilities with 3,300 MW of capacity, many of which were co-generation facilities located along the East Coast. Cogentrix eventually formed a new unit it called Calypso and contributed 14 of its domestic power plant interests into the unit. Subsequently Cogentrix sold two of those facilities out-right.

... San Diego Gas & Electric agreed to buy 125 MW of concentrated solar power capacity to be developed by France-based **Soitec** under two 25-year deals, the companies said. Soitec will supply SDG&E's projects with solar modules from a new manufacturing facility it will build in the San Diego area. The factory will have an annual production capacity of 200 MW. If approved by the **California Public Utilities Commission**, the proposed solar facilities will be in San Diego County, near SDG&E substations. The agreements are in addition to the three contracts the two companies signed in April for 30 MW of concentrated photovoltaic solar power. Soitec has yet to announce the exact locations of the projects, SDG&E spokeswoman Stephanie Donovan said. The projects will use ground-mounted, dual-axis tracking concentrated photovoltaic technology, which uses lenses to concentrate sunlight on small solar cells that convert light into electricity.

... We Energies is moving forward with a 50-MW biomass cogeneration project, spokesman Brian Manthey said. The **Wisconsin Public Service Commission** approved the $255 million project, with various conditions, partly to lower its cost to ratepayers. After reviewing the PSC's written order, the Milwaukee-based utility placed an order for a boiler for the project to keep it on schedule, Manthey said. In late April, the PSC's three commissioners said they would not support the utility's original plan for the project, which would cost ratepayers $123/MWh. In response, **Domtar Paper** agreed to pay more for steam from the plant in Rothschild, Wisconsin, lowering the cost to ratepayers to $115/MWh. We Energies argued that at the lower cost, the biomass project was close to the cost of wind generation. The PSC made additional changes to the proposal's capital cost allocation

PLANTS AND PROJECTS *(continued)*

that lowered the cost to $111.50/MWh. Domtar's board of directors must approve the new arrangement for it to be final. We Energies and Domtar are required to report back to the PSC by late June on the final decision on the plant. If the plant is built, We Energies expects to meet its RPS requirements through 2016, Manthey said. After that it will need about 400 MW of wind, or an equivalent resource.

... **Northern States Power**'s Prairie Island nuclear plant southeast of Minneapolis is in the final stage of the **Nuclear Regulatory Commission**'s approval process to extend the operating licenses for the two reactors, the 590-MW Unit 1 and 585-MW Unit 2. The NRC May 17 issued a final statement on extending their licenses by 20 years. NRC staff concluded earlier there are no environmental impacts that would preclude renewal. According to its website, the NRC plans to make a final decision next month. Unit 1's license expires August 9, 2013 and Unit 2's October 29, 2014. NSP, a subsidiary of **Xcel Energy**, submitted the renewal application on April 11, 2008.

... The **Louisiana Public Service Commission** voted 4-0 in favor of a settlement agreement calling for **Entergy Louisiana**'s Little Gypsy-3 repowering project to be formally canceled and the utility to be permitted to recover $200 million in project costs through the sale of securitization bonds backed by a 10-year rider on customer bills. At Entergy Louisiana's request, the PSC in May 2009 approved the utility's request to suspend work on the $1.76 billion Little Gypsy project, which called for converting a natural gas-fired peaking unit in Montz, Louisiana, to a 535-MW, petroleum coke and coal-fired facility. The commission approved Entergy's plan to repower Little Gypsy-3 in November 2007, but the utility determined by early 2009 that lower natural gas prices, uncertainty about future federal regulation of greenhouse gas emissions, and a weak economy had undermined the economic rationale for the project, and that work on it should be suspended. The securitization approach for canceled-project cost recovery is permitted under a 2010 Louisiana law known as Act 988. The approved Little Gypsy rate rider is expected to raise the monthly bill of a 1,000-kWh/month residential customer of Entergy Louisiana by $1.03. Entergy Louisiana, the PSC staff, **Louisiana Energy Users Group**, **Marathon Oil** and **Occidental Chemicals** agreed to the settlement.

... Nova Scotia could get its most extensive — and expensive — wind farm if a consortium of Canadian, US and Korean companies follows through with plans for a project in the Cape Breton Highlands that could generate up to 300 MW and cost $3 billion or more. **Highland Power**, based in Sydney, the largest city on Nova Scotia's Cape Breton Island, is leading the development. Other members include **Northern Innovations**, **Mi'kmaq First Nations**, **RMS Energy**, **Daewoo Shipbuilding and Marine Engineering** and US companies **Starwood Energy Capital** and **Charles River Associates**. The wind farm would be located in an isolated area near Baddeck, gateway to the world-famous Cabot Trail, a scenic, 185-mile route that loops around the northern, mountainous tip of Cape Breton. "It's a project we're very interested in investing in," Tom Johnson, spokesman for Starwood Energy Capital, said. Johnson said the project is in the "early stages." Preliminary plans call for the wind farm to be built in phases, with the initial capacity from 100 MW to 200 MW. Construction could begin in 2013 or 2014. It would be the biggest wind energy producer, by far, on Nova Scotia. Earlier this year, **Shear Wind**, headquartered in Halifax, Nova Scotia, started up the 62.1-MW Glen Dhu wind farm between Pictou and Antigonish counties in the northern part of the province, currently the largest. The wind farm has a 20-year power purchase agreement with **Nova Scotia Power**.

(continued from page 17)

and wind generation to replace it with excess federal hydropower during the spring runoff period to avoid violating environmental laws with too much spill.

BPA provides the replacement power at $0/MWh, but will not sell it at negative prices as other traditional generators would. Under negative pricing, sellers pay buyers to take the power they are producing.

The policy has angered wind interests, who stand to lose their production tax credits and renewable energy certificates worth roughly $40/MWh if their power is curtailed.

Some wind participants began weighing in on the curtailments, continuing to decry environmental redispatch as a flawed policy.

"It will be interesting to see whether, in each of these situations, all other options were in fact pursued," said Rob Gramlich, senior vice president of public policy for the American Wind Energy Association. "For example, was there power line capacity available and were there other resources that could have been ramped down instead of breaking contracts with wind generators?"

On May 17, the head of BPA, Steve Wright, said in an interview that environmental redispatch is not the ideal way to deal with oversupply conditions.

"I can't say that I'm happy with the solution," Wright said. "It's just, given lousy choices, one has to be made.

He added that, "there is no question it will be a cost to the wind community."

BPA has remained steadfast that it will not absorb that cost itself in the form of negative prices or other compensation to wind generators. That expense would be transferred unfairly to BPA customers and would violate the agency's mission of providing cheap hydro power.

While there is no precise price tag to attach to wind curtailment, one wind industry source said the value of a production tax credit and of a renewable energy certification combined could be roughly $50/MWh. That would mean that May 18's first curtailment, which BPA estimated at 1,400 MWh, could have represented a $70,000 loss for affected wind generators.

Wright said BPA warned each new wind generator of the potential for oversupply as their plants were coming online.

"I always assumed we would be able to find a more elegant solution than has been uncovered so far," Wright said. "But it's not a surprise to us, and not a surprise to the wind community."

Wind interests argue that BPA should have taken proactive steps to prevent unmanageable oversupply conditions as the agency allowed roughly 3,000 MW of new wind power to con-

nect to its grid in the past few years.

Robert Kahn, executive director of the Northwest and Intermountain Power Producers Coalition, called the oversupply situation "predictable and preventable," and said events like that which occurred on May 18 will likely continue at a greater magnitude as the spring runoff period peaks.

"I think there is going to be a lot of this," Kahn said. "This is just the beginning of many, many hours over many weeks."

The Northwest is facing an unprecedented spring runoff period, with current snowpacks well in excess of 150% of normal in numerous locations. Current estimates put streamflows on the Columbia River system around or above 130% of normal at many dams.

While some stakeholders opposed to environmental redispatch have questioned the policy's legality or even threatened to file litigation if it was implemented, it remains to be seen whether any legal action will be taken.

On May 18, a spokesman for the Federal Energy Regulatory Commission said the commission had not received any filings related to environmental redispatch.

— Hilary Costa

Three coal gasification projects pin hope for Illinois legislative OK on ComEd bill

In the final days of the Illinois Legislature's spring session, three multibillion-dollar coal gasification projects are attempting to rise from the collective ashes of a gubernatorial veto and setback by the state Senate.

Lobbyists for Tenaska, Power Holdings of Illinois and Leucadia National talked with lawmakers last week about attaching revised coal gasification plant language to a revised utility infrastructure bill to be submitted by Commonwealth Edison, an Exelon subsidiary and the state's largest electric utility, according to several state and coal industry sources.

"It wouldn't surprise me," Steve Brown, top aide to House Speaker Michael Madigan, said May 17. "But nobody has seen the full details."

Added David Kolata, executive director of the Citizens Utility Board, a Chicago-based consumer watchdog: "I certainly heard that Tenaska, Leucadia and Power Holdings have revised their bill and are trying to attach it to the overall energy efforts of ComEd. I don't know to what extent that will be successful or not ... it's too early to tell."

H.B. 14, known as the "ComEd bill," has met with strong resistance in the General Assembly and from Governor Pat Quinn, who threatened earlier this month to veto it if it reached his desk.

ComEd is expected soon to unveil its new and, presumably, more politically palatable proposal. And when it does, the coal gasification plant developers hope to make a last-ditch stand to win final legislative approval for the trio of projects: Tenaska's 602-MW Taylorville Energy Center in Christian County, a $3.5 billion facility; Power Holdings' $2 billion-plus synthetic natural gas plant near Waltonville in Jefferson County; and Leucadia's $3 billion SNG plant on Chicago's South Side.

A bill authorizing the Tenaska project passed the House of Representatives late last year but was defeated in the Senate in early January. The legislation would have required the state to purchase all of Taylorville's output at above-market rates, and large industrial customers complained they could be subjected to hefty price increases. Democrats control both the House and Senate, and Quinn is a Democrat.

In March, Quinn, citing "inadequate consumer protections," dealt a crushing blow to Power Holdings and Leucadia when he vetoed legislation for their projects. As passed by the General Assembly earlier this year, the bills would have forced major utilities in the state to buy syngas produced by both plants. Quinn and CUB, an agency Quinn helped to create more than a quarter-century ago, said they feared the Leucadia and Power Holdings plants would lead to higher energy costs for Illinoisans.

Since his veto, however, the governor has signaled his intent to back coal gasification so long as it does not adversely affect consumers, leaving the door at least slightly open to a potential Power Holdings/Leucadia resurrection.

Kolata said New York-based Leucadia, in particular, "has proposed some pretty significant changes to their bill, which is a step in the right direction." He was not privy to all the details, and Leucadia officials could not be reached for comment.

Jana Martin, spokeswoman for Tenaska, an Omaha, Nebraska, said she did not have "any update at this time" on Taylorville. Although Power Holdings officials could not be reached for comment Tuesday, the company previously has acknowledged interest in reviving its ill-fated Illinois bill.

In the meantime, the clock is ticking. Lawmakers are scheduled to recess their spring session on May 31 and return in the fall for a veto session. Despite the apparent paucity of time, most observers believe it is not too late to get something done.

"There's plenty of time," said Brown, whose boss has supported all three coal gasification projects.

Kolata echoed that sentiment. "This is a developing situation," he said. "There's still plenty of time to get something passed by the end of May."

— Bob Matyi

FERC assessment paints stable picture for summer power; demand-side to help

Improvements in electricity and natural gas infrastructure and other key market factors add up to a stable energy supply outlook for the summer cooling season, according to the Federal Energy Regulatory Commission.

The US will have enough generating capacity to meet expected power demand, FERC staff said in the agency's latest energy market and reliability assessment. Generation reserve margins will be adequate heading into peak season, it said, adding that demand this summer is unlikely to be different from last summer.

Relying on preliminary data from North American Electric Reliability Corp., FERC's report pegged summer demand at between 700 GW and 800 GW. "Overall, NERC forecasts that total US load, when weather-adjusted, will rise by less than 1% when compared to last year, while the capacity available on-peak is projected to rise by 3%,"

said David Andrejcak, deputy director of the Office of Electric Reliability.

NERC is scheduled to release its comprehensive summer assessment this week.

As part of that projection, Andrejcak said, NERC expects a 13% increase in demand-side management, to about 34 GW, because of widespread focus on it in the electricity industry. "This change is primarily driven by increases in demand participation in the PJM and Midwest ISO market areas," he said.

Several new large gas pipelines and power transmission lines should help alleviate congestion concerns, according to FERC's report.

On the gas side, the 430-mile expansion of Florida Gas Pipeline is expected to increase gas flows into Florida by 35% and could prevent the kind of price spikes that occurred during peak gas demand for power plants in 2010, Alan Haymes of the Office of Enforcement said. He noted that generation accounts for 85% of gas use in the state.

Similarly, the addition of the 42-inch-diameter Ruby Pipeline from the Rockies to the West Coast is expected to increase supplies there by 1.5 Bcf/d once it goes into service in July.

The 218-mile, 500-kV Trail Project in PJM Interconnection should help alleviate electricity congestion in the Northeast, said Haymes.

In the West, strong hydropower potential due to above-average snowpack should trump any congestion concerns in the region. "Abundant hydro supply has placed downward pressure on [power] prices in the West and is expected to continue to due so through most of the summer," Haymes noted, adding that average snowpack in California and the Northwest was 150%-170% above normal.

Forward electricity prices for summer continue to rise by double digits in many regions. FERC noted a 22% increase in New England from the $49.78/MWh a year ago, a 15% increase in PJM West from $55.01/MWh in 2010 and an 11% increase in New York from $70.50/MWh last year.

Despite the promise of shale supplies and the hope that new pipelines will increase gas deliveries, FERC noted rising forward prices because more power plant demand for gas "is pretty consistent across the country," Andrejcak said.

While the National Oceanic and Atmospheric Administration expects above-normal temperatures from the Rockies eastward, drought conditions are expected to continue in Texas and the Southwest. Consequently, the Electric Reliability Council of Texas has increased its reserve margin in anticipation of increased summer demand, Andrejcak said.

— Martin Coyne

Oglethorpe details several possible capacity additions, including small modular reactors

Despite its recent acquisition of several independent power plants and a 30% stake in two planned 1,117-MW nuclear units at the Vogtle station, Oglethorpe Power may be called upon by some of its member electric cooperatives in Georgia to build peaking capacity mid-decade, and may consider building one or more modular nuclear units by the early 2020s.

Oglethorpe President and CEO Thomas Smith said during a conference call with energy analysts and media that the statewide co-op group expects to meet most of its members' incremental power needs through the Vogtle expansion and the recent acquisition of Murray I and Murray II — natural gas-fired,combined-cycle units near Dalton, Georgia, with a combined capacity of 1,220 MW — and two gas-fired peaking units totaling 785 MW.

Smith added, however, that several of its member co-ops need to either extend power purchase agreements that expire by the middle of this decade or replace them, and the baseload requirements of all its members will continue to grow, even with the 660 MW of baseload capacity Oglethorpe will add to its system with the completion of Vogtle Units 3 and 4 in 2016 and 2017, respectively.

"That's why we're interested in small modular reactors," said Smith. Several companies are planning to apply to the Nuclear Regulatory Commission for modular-unit design certifications as soon as 2012, including Babcock & Wilcox for its mPower unit, NuScale Power for its NuScale unit, and Holtec International for its "Safe Modular Underground Reactor."

Georgia co-ops also may benefit from the possible addition of an 850-MW coal unit planned for a site in Washington County by Power4Georgians, a group of five co-ops that are among Oglethorpe's 39 members, Smith said. The Power4Georgians' project faces continued legal and permitting challenges, but the group still hopes to complete the facility as soon as 2017-18.

In the nearer term, Smith said it is possible that some of Oglethorpe's members may ask the statewide group to develop one or more peaking units by 2016 to replace expiring third-party PPA those co-ops hold with others, particularly if the co-ops are not able to extend those agreements.

The Oglethorpe executive said that the output of the Murray I combined-cycle unit is under contract to Georgia Power through mid-2012, and that the available output of both Murray I and II will be marketed to others until Oglethorpe's member co-ops expect to start needing the units' power in 2015-16. He noted that interest from others in buying power from the Murray units has been high since Oglethorpe closed on their purchase from KGen Power in early April.

Smith also said that the Vogtle expansion project remains on schedule despite general concerns raised about the future of nuclear power after the Japanese crisis, and that Oglethorpe and its partners in the project expect to be granted a combined construction and operating license from the NRC in the fourth quarter of this year. "Our best target [for securing the COL] would be early December," he said.

Oglethorpe owns or leases about 7,050 MW and operates or schedules another 1,287 MW on behalf of its co-op members, whose combined system peak is about 9,000 MW. The co-ops secure the balance of their needs through third-party PPAs. The co-ops affiliated with Oglethorpe serve all or part of 151 of Georgia's 159 counties, and a total of 1.8 million customers.

— Housley Carr

DSM programs will cut New York summer peaks back to 2006 levels, says PSC staff

Demand-side management programs will make a significant contribution in helping New York state meet power demand this summer, the Public Service Commission was told last week.

The DSM programs bring the summer load predictions down

to 2006 levels, the PSC staff said. The state has available in-state supply of 40,339 MW, including 2,053 MW of demand-side management programs. External purchase contracts add 1,821 MW, bringing total supply to 42,160 MW.

The PSC expects peak demand of 32,712 MW this summer, and the utilities will need a 15.5% reserve or an additional 5,070 MW. That leaves the state with an excess margin of 4,378 MW. The staff also reported that transmission and distribution systems are in good shape to meet summer load.

The PSC also voted to require major utilities to give net-metering customers the option of selecting when they can cash out excess net-metering credits.

"Our decision today provides consumers with additional choices and greater flexibility to save money. It also makes it easier and more understandable to net meter," said Commissioner Chairman Garry Brown. The change will allow net metering customers to receive higher payments if they choose to cash out during the summer months when electricity is more expensive. Previously, net-metering customers received a credit for excess generation during the next billing cycle.

The PSC also agreed to let Consolidated Edison spend $25 million over the next four years on targeted energy efficiency measures to permanently reduce load by 100 MW. The new program will target measures that will defer or avoid transmission and distribution upgrades.

In a separate action, the PSC allowed New York State Electric & Gas and Rochester Gas and Electric to eliminate the 100-kW demand threshold for non-residential commercial and industrial custom rebate energy efficiency programs, which will allow smaller businesses to participate. The PSC said it would allow other utilities to do the same. The two companies' business efficiency programs cover refrigeration, energy management systems, industrial processes and lighting.

Finally, the PSC accepted an independent audit report of Central Hudson Gas & Electric. Unlike the PSC's previous audits of Con Ed and National Grid USA, there were no major criticisms of the smaller company. But the audit did recommend CHG&E better document its practices.

— Pam Radtke Russell

Two environmental groups sue Michigan over air permit for proposed Holland plant

Two environmental groups sued the Michigan Department of Environmental Quality last week to overturn an air permit issued by the agency in February for Holland Board of Public Works' proposed 78-MW coal plant (*EUW*, 21 Feb, 8).

In the suit, filed in Ingham County Circuit Court in Mason, Michigan, the Sierra Club and Natural Resources Defense Council contend, among other things, that DEQ "improperly ignored the lack of the need for the proposed coal plant and rejected cleaner energy alternatives, such as energy efficiency, wind, solar, combined heat and power, and existing natural gas combined cycle capacity."

Jan O'Connell, energy issues organizer for the Sierra Club's Beyond Coal Campaign, said that instead of spending money on a new coal plant, Holland should be investing in alternative energy. The Sierra Club says 158 proposed coal plants across the US have been canceled or stopped in recent years largely because of increasing Environmental Protection Agency restrictions on the burning of coal.

DEQ's decision to issue the permit reversed an August 2010 ruling by the same agency, then part of the administration of former Governor Jennifer Granholm, a Democrat, which denied the permit after concluding the new plant was not needed. That decision was prompted by a Granholm February 3, 2009, executive order largely viewed as a *de facto* moratorium on new coal plant applications.

Holland appealed and last December a judge determined the state had exceeded its legal authority in denying the permit on the basis of need. Judge Jon Van Allsburg of the Ottawa County Circuit Court remanded the case back to DEQ, now under the direction of new Republican Governor Rick Snyder, who took office in early January.

Andree Keneau, spokeswoman for the Holland Board of Public Works, said the city has hired a private consultant to prepare an energy plan for Holland. The study, scheduled to be completed in the fall, "is a broad picture of how to generate electricity," she said. It is possible a new plant could burn wood waste and/or tire-derived fuel in addition to coal. The DEQ permit also authorizes Holland to use petroleum coke, tire-derived fuel, sewage sludge and wood waste as fuel.

The study also is expected to provide an updated cost estimate for the project. The city previously estimated a 78-MW plant using circulating fluidized bed technology would cost about $250 million.

The new plant would replace the oldest of three coal units at Holland's 60-MW James DeYoung station, which is more than a half-century old.

The DEQ also is considering issuing an air permit for Wolverine Power Cooperative's 600-MW coal plant proposed for Rogers City. In January, another judge also overturned the DEQ's decision last year to deny Wolverine's permit for the $2.5 billion project.

DEQ officials did not respond to calls seeking comment on the lawsuit.

— Bob Matyi

FERC approves settlement for NYC plant to get $3 mil compensation for oil burning

The Federal Energy Regulatory Commission approved a settlement concerning compensation of TC Ravenswood for costs of burning oil instead of natural gas at its 2,480-MW New York City plant.

The arrangement addresses Ravenswood's costs for the period of May 1, 2010, through April 30, 2014. It also outlines how the TransCanada subsidiary would meet and be compensated for complying with the state minimum oil burn rule in the long term and related changes to the New York Independent System Operator tariff.

Parties to the settlement include Ravenswood, NYISO, Consolidated Edison, Orange and Rockland Utilities, Constellation Energy Commodities Group, Astoria Generating, Independent Power Producers of New York and the New York

State Public Service Commission (Docket No. EL10-70).

In a complaint, Ravenswood had alleged that NYISO owed it millions of dollars in compensation for switching to fuel oil during the period of June through September 2009. The complaint was accompanied by a proposed new minimum oil burn service rate that FERC subsequently rejected because such service falls under the "exclusive purview" of NYISO.

The New York State Reliability Council's Rule I-R3 requires the state's bulk power system to operate so that loss of a single gas facility does not result in loss of load in New York City. The minimum oil burn rule requires designated dual-fuel generating units, including Ravenswood's plant in Queens, to switch from gas when ordered to do so.

Under the NYISO tariff, units that are required to switch are eligible to recover variable operating costs associated with burning the alternative fuel. Ravenswood claimed that the tariff did not compensate the generator for its full cost of service.

For complying with the state rule from May 2009 through April 2010, Ravenswood will receive a one-time payment from the ISO of $7 million. This amount represents about 70% of the costs Ravenswood claimed, according to the settlement.

In addition, Ravenswood will be paid about $3.3 million plus a 40 cent/barrel operations and maintenance charge for complying with the minimum oil burn rule for the period of May 1, 2011, through April 30, 2012. For those same months in 2012 and 2013, it will be paid about $3.4 million plus a 41 cent/barrel O&M charge. For compliance with the rule from May 2013 through April 2014, it will be paid about $3.5 million plus a 42 cent/barrel O&M charge.

— *Esther Whieldon*

MERGERS & ACQUISITIONS

AES makes short-term promises to state regulators in DPL merger filing in Ohio

Global power producer AES Corp., in a new merger filing in Ohio late last week, is making several short-term commitments to state regulators regarding takeover target DPL, including promises of no involuntary workforce reductions for two years and to keep the headquarters of DPL and its Dayton Power & Light subsidiary in Dayton at least through 2013.

AES also told the Public Utilities Commission that DPL would continue to provide corporate contributions and community support in the Dayton area "at levels substantially consistent" with current amounts for at least two years once the $4.7 billion cash and debt deal is final (Case No. 11-3002-EL-MER).

The planned acquisition of century-old DPL, unveiled April 20 by Arlington, Virginia-based AES (*EUW*, 25 April, 1), is driven at least partly by a more favorable outlook for power prices, AES has said. AES agreed to pay $30 for each of DPL's 116 million shares, representing an 8.7% premium over DPL's closing price of $27.59 on April 19, for a total cash value of $3.5 billion. AES plans to absorb about $1.2 billion in DPL debt.

Included in the proposed case schedule is AES' request for a final PUC order within six months. "This is slightly more aggressive than the procedural schedule that we established" in Cincinnati Gas & Electric's merger with Public Service Indiana in 1994 to form Cinergy, said commission spokesman Matt Butler. Duke Energy subsequently acquired Cinergy.

In addition to the PUC, the corporate combination needs approvals from the Federal Energy Regulatory Commission, Securities and Exchange Commission, Federal Communications Commission, Federal Trade Commission and Department of Justice. AES hopes to close the transaction by the end of this year.

Among AES' far-flung holdings in 28 countries on five continents are 14 utilities serving 11.5 million customers and 40,000 MW of generating capacity. Altogether, AES employs 29,000 people. DPL, in contrast, is much smaller, serving about 500,000 retail customers in west-central Ohio and owning 3,800 MW of capacity, 2,800 MW coal-fired with the remainder natural gas and diesel.

AES noted it has a 25-year history of managing fossil fuel assets, similar to DPL's, and controls more than 30.5 GW of fossil fuel and 8 GW of hydro generation worldwide.

According to DPL spokeswoman Lesley Sprigg, her company currently has 1,510 employees. None of them would lose their jobs because of the merger, AES said.

AES also agreed to preserve "DP&L's decision-making authority, including its commitment to maintain DP&L's operating headquarters in Dayton, Ohio, and DP&L's name, for at least two years following the merger."

DP&L's electric rates are frozen through 2012 under an existing electric security plan approved by the PUC and would not rise as a result of the merger, AES added.

As part of the AES group, DP&L and its customers would have access "to an extensive global network of technical expertise and resources, which will enhance DP&L's ability to compete with the substantially larger Ohio utilities," AES said. The state's other investor-owned utilities include FirstEnergy, American Electric Power and Duke Energy Ohio, a subsidiary of Charlotte, North Carolina-based Duke Energy.

AES also suggested DP&L could benefit from AES' ownership of Indiana's Indianapolis Power & Light, acquired about a decade ago. Because DPL and IP&L are in close proximity to one another, "it will be possible for DP&L and IP&L to provide better emergency response services and share best practices," AES said. It said IP&L's customer call center has been recognized as a top-tier operation and IP&L has ranked "in the top quartile for overall customer satisfaction, as rated by J.D. Power and Associates," which, like Platts, is owned by The McGraw-Hill Companies.

IP&L currently has extensive demand-side management offerings for all residential customers and the vast majority of its commercial and industrial customers, AES said. In terms of smart grid, IP&L was awarded a $20 million grant by the Department of Energy as part of a nearly $50 million planned investment in advanced metering infrastructure deployment,

Duke's Rogers foresees more consolidation to meet capital and repositioning needs

Faced with the need to clean up their generating fleets, modernize and secure transmission lines and keep electricity rates affordable, the utility industry is likely to undergo more consolidation in the coming years, Duke Energy Chairman, CEO and President Jim Rogers said.

"Business as usual is not the way forward," Rogers told an audience of energy industry executives and analysts at the 2011 Deloitte Energy Conference in Washington last week.

Lacking a national energy policy to direct the industry, utilities with market capital of less than $5 billion will find it difficult to raise the money needed to achieve their environmental and economic targets, Rogers said.

"To raise capital to remake our fleets and build our grid it is going to require greater consolidation," he said, adding that industry mergers and acquisitions will come "in waves" as companies seek to position themselves "extremely well" to deal with environmental and other challenges in the 21st century.

Duke Energy, headquartered in Charlotte, North Carolina, and Progress Energy, based in Raleigh, are undertaking a $26 billion merger that would create the largest electric utility in the country.

Asked whether the utility is eyeing other acquisitions, Rogers, a veteran of three mergers, left the option open. "Our first assignment is to close this deal," Rogers told reporters. "Then once we close it, get it integrated and deliver the benefits from the combination, then we'll be in a better position to talk about what comes next."

The utility will still have to provide low-cost, reliable service, Rogers said. "Bigger is only better if it turns out for the best," he said.

Utilities also will face grid investments to ensure reliability and prevent cyberattacks, he said. To that end, their mission also should involve building energy efficiency into consumers' homes and businesses and convincing state regulators to allow utilities to profit from efficiency programs as they do from capital projects, he said.

"We are the ones that should be investing in the homes and businesses and helping them, particularly in the face of rising prices," Rogers said. Electric utilities are "in the best position to make productive gains in the reduction of electricity [use] in homes and businesses. We need to pursue this in a very aggressive way."

Toward that end, Duke Energy is also piloting an energy efficiency program in 100 Charlotte homes that involves sensors on appliances to cycle up and cycle down according to their use. Rogers said the customers have reported no difference in the quality of their service and they have been able to reduce their demand on peak by 20%.

"The most environmentally benign power plant I can build is the one I don't build," he said.

Still, to meet these goals, electricity prices will have to increase, he said, but utilities can act now while there are low interest rates "to smooth out cost impact on consumers." If utilities wait until pending environmental regulations take effect, they will be scrambling for capital and making hasty decisions about whether to close units or retrofit, he said.

— Cathy Cash

distribution automation and DSM offerings, including an electric vehicle program.

The Ohio Office of Consumers' Counsel expects to intervene in the merger case. The agency's intent, said spokesman Anthony Rodriguez, "will be to look at the [merger] to ensure residential customers are protected from any harm related to it."

AES and DPL filed with the Federal Energy Regulatory Commission May 18 for approval of the deal.

— Bob Matyi

RENEWABLES

Kansas governor moves to protect tallgrass area for tourism, killing region's wind development

A 10,895 square mile region in east-central Kansas' Flint Hills viewed favorably by some wind developers because of its good wind resources and proximity to electric load should be off-limits to new wind farms so the newly named "Tallgrass Heartland" can focus on eco-tourism, Kansas Governor Sam Brownback said last week.

Brownback's plan, which more than doubles the 4,673-square-mile area in the Flint Hills that former Governor Kathleen Sebelius sought to protect starting in 2005, is expected to either complicate or kill efforts by developers to build wind projects in the region, The area accounts for about one-eighth of Kansas' total land area.

"We knew nothing about it. Neither did the other counties, as far as I know," Cowley County Commission Chairman Gary Wilson said of Brownback's plan, whose no-build area for prospective wind farms includes the eastern three-quarters of Cowley County, southeast of Wichita near the Oklahoma state line.

"It apparently was an executive decision," Wilson said. State legislators from the area were blindsided by the governor's move and hope to somehow undo it at the Kansas Legislature, he said.

BP Wind Energy for several years has been seeking to advance a large wind project in the northeastern part of Cowley County, Wilson said, and the project had been expected to provide both tax revenue to the cash-strapped county and lease payments to ranchers and farmers there. "It just seems like everything we had worked for is gone, with no explanation," he said.

The county commission chairman said he believes that BP Wind Energy and other developers are being pressured to withdraw their plans for wind projects in the Flint Hills, and that no developers will seek to develop new projects there, knowing that the Brownback administration will oppose their efforts. Westar Energy and Kansas City Power & Light have signed onto

the governor's plan, and therefore would likely reject any wind-power offers from the protected region, Wilson said.

BP Wind Energy spokeswoman Amanda Abbott confirmed that the company has been developing a wind project of up to 300 MW in Cowley County, but has been unable to secure a power purchase agreement that would let the project advance to financing and construction. She declined to speculate on whether Brownback's plan will prevent the project from proceeding, except to note that part of Cowley County is outside the region the governor identified for protection.

Gamesa recently scrapped its plan to build a 150-MW wind farm in Elk County, which is within the Tallgrass Heartland area delineated by Brownback, said a source familiar with the project who declined to be identified because of the sensitivity of the matter. He said Gamesa decided not to proceed with the project shortly before the governor unveiled his plan.

Brownback said at the start of the Flint Hills Visioning Summit in Elmdale on May 17 that the native tallgrass prairie in the region is "a beautiful thing that ... is now being discovered by the rest of the world."

Only 4% of the nation's original tallgrass prairie remains intact, and almost all of it is in the region in which the governor said he believes no new wind farms should be built. He called on state and local officials to focus their economic development efforts on eco-tourism, including hiking, horseback riding and bicycling.

Brownback, a leading advocate of a federal renewable electricity standard when he was a US senator, said in announcing his Tallgrass Heartland plan that existing wind farms in the region will not be affected by the plan; nor will projects that already hold PPAs but are not yet online.

The protected region's only existing wind farm is Iberdrola Renewables' 150-MW Elk River wind farm in Butler County, which sells its output to Empire Electric District. Iberdrola spokeswoman Jan Johnson said that the company has "pulled back" from a planned expansion at Elk River, but declined to elaborate. The only other wind project in the region that holds a PPA is Enel Green Power's 201-MW Caney River project, which is under construction in Elk County and expected to begin commercial operation in 2012. The Tennessee Valley Authority is under contract to buy the output of the project.

Projects at the edges of the newly delineated protected area apparently can proceed, including RES Americas' plan for a 200-MW wind project of up to 250 MW in Lyon and Osage counties; its site is just outside the Tallgrass Heartland. Asked about how the project ended up just outside the boundaries of the no-build area, Shalini Ramanathan, vice president of development for the South-Central region, said RES Americas, "along with several other members of The Wind Coalition, presented the governor with the wind industry's views on the need for a favorable investment climate in Kansas. We appreciate the governor's continued support for wind power in the state."

Brownback noted that other parts of the state — especially western Kansas — are well suited for wind-farm development, and that he will support efforts not only to build new wind farms there but to build the new transmission lines that will be needed to transmit their output to population centers to the east.

— Housley Carr

Wisconsin bill would allow large hydro to meet RPS, turning state into renewables 'backwater'

The Wisconsin Legislature is poised to approve a bill that would allow utilities to use large hydroelectric resources to meet the state's renewable portfolio standard, a move renewable supporters say would stifle in-state development.

The Wisconsin Senate passed S.B. 81 on a 21-11 vote May 17. The Assembly also approved the bill, Democrats delayed a final vote for a procedural move. Both chambers are controlled by Republicans.

"It will pass," said Ed Blume, a spokesman for Renew Wisconsin, an advocacy group that opposes the bill. Groups like Renew Wisconsin contend that the bill will reduce opportunities for in-state renewable development.

"If passed, this bill would effectively turn Wisconsin into a renewable energy backwater for the next 20 years," Renew Wisconsin Executive Director Michael Vickerman told a joint legislative utility committee meeting earlier this month.

Wisconsin Public Service supports the bill because it would allow the utility to buy baseload power from a dam Manitoba Hydro plans to build later this decade in Canada. WPS, an Integrys Energy Group utility based in Green Bay, Wisconsin, is in talks to buy about 100 MW from Manitoba Hydro's proposed 700-MW Keeyask project. Wisconsin's RPS limits hydroelectric resources to 60 MW.

Renew Wisconsin supported lifting the hydroelectric limit last year, but only when it was part of a larger bill that would have increased Wisconsin's RPS to 25% by 2025. The bill died at the end of the legislative session.

The hydroelectric bill, along with uncertainty for wind farm siting rules and the fact that some of Wisconsin's largest utilities already meet the state's 10% by 2015 RPS, dims the outlook for renewables in the state. "In the current climate, we don't see any large renewable projects, possibly for years to come," Blume said.

Further, in a search for co-sponsors, a draft bill is being circulated in the Wisconsin Legislature that would end a current provision in the RPS that limits the use of banked renewable energy credits to four years. Under the bill proposed by Republican Representative Erik Severson, RECs would have an indefinite life span. The bill would essentially gut the RPS, allowing utilities to buy credits that were produced as far back as 2004, according to Vickerman.

Severson, a first-time lawmaker on the Assembly's Energy and Utilities Committee, contends that expanding the "shelf-life" of RECs would lower ratepayer costs. "It is unfair and fiscally imprudent to allow the value of a utility's investment in renewable energy to expire, especially when the slowing economy has placed upward pressure on rates," Severson said in a

note to fellow lawmakers. "Customers have felt the fiscal impact of this four-year shelf-life at home, as they have been forced to continually fund the over-production of necessary credits."

— Ethan Howland

FINANCE

National Grid chief just about rules out selling US power and natural gas units

National Grid's chief executive last week just about ruled out selling US power and natural gas utilities, while emphasizing the need to boost their profitability.

"We continually review the many businesses we own and evaluate their long-term value and how it aligns with the strategic direction of National Grid … Where we don't see a long-term strategic fit or where we believe the time is right to maximize value, we will consider divesting, as was the case in New Hampshire," said Steve Holliday during the May 19 webcast on results for the fiscal year ending March 31, 2011.

Grid December 9 announced a deal to sell New Hampshire's Granite State Electric and EnergyNorth Natural Gas for $285 million. Grid booked a £34 million charge on impaired "goodwill" at those utilities.

On May 17 Nomura Equity Research said "in our view [the company] is now actively considering an exit from the US," predicting a decision by March 2012.

As usual, Grid declined to comment on that report. But during the webcast's question and answer segment, an analyst asked Holliday whether "for all practical purposes we can now rule out a big bang breakup of the group either by wholesale sale of the US business or by an IPO [initial public offering] of the US business, for all practical purposes? Yes or no will do."

"As we look at the mix of assets we've got today, and we'll keep looking, it's not like by the 19th of May the decision is made, these are the long-term businesses," Holliday responded.

"It's going to change, so there will be lots of decisions over a long period of time. But about that mixture, a wholesale exit from the US, when you look at today in May 2011 at what that would do to National Grid, does not look like a value constructive thing to do. It does not.

"You should never rule out anything in terms of selling this and buying that, etc., etc. We need to keep this mix of businesses under review … When we're ready to make any announcement about things that flow out of those constant reviews, we'll do so. But right now the focus is on the mix we've got today."

"I think that was a yes," the analyst said.

Grid bought KeySpan, holding company for gas utilities in Massachusetts, New Hampshire, New York and Rhode Island, for about $7.35 billion in cash August 24, 2007, exactly a year after buying the Rhode Island gas utility operations of Southern Union for $498 million.

At that time KeySpan also owned 6,600 MW of generation. The Public Service Commission conditioned approval for the acquisition on Grid agreeing to sell the 2,480 MW Ravenswood plant in Queens. But Grid still owns about 4,000 MW of generation on Long Island, and also operates the Long Island Power Authority's transmission and distribution system.

Grid entered the US with the March 2000 purchase of New England Electric System and in January 2002 bought Niagara Mohawk Power.

US operating profit up 31.4%, mainly on 'timing differences'

For the fiscal year ending March 31, pre-tax operating profit after exceptional items from US operations gained 31.4% to £1.69 billion. Exchange rates had virtually no effect with an average $1.57=£1.00 for the fiscal year, compared to $1.58=£1.00 a year before. (The current rate is about $1.62=£1.00.)

Total operating profit was up £479 million or 15.3% to £3.6 billion. But adjusted for timing differences in both years, the increase was only £43 million or 1.3% to £3.33 billion.

That reflected a £163 million excess of costs over amounts recovered in rates in fiscal 2009-10, and a £270 million overrecovery in the last fiscal year. This year Grid expects an underrecovery of about £335 million, noted Andrew Bonfield, the new finance director.

US power operations saw operating profit surge £222 million or 59.2% to £597 million, but adjusted for timing differences, rose by £78 million or 19% to £489 million. Results reflected rate hikes for Massachusetts Electric and Rhode Island's Narragansett Electric, but not for NiMo.

NiMo benefitted from hotter 2010 summer weather — for the last time, since the Public Service Commission approved decoupling in its January 2011 rate order, Bonfield pointed out.

But NiMo did not benefit from what Grid has labeled the "disappointing" New York Public Service Commission January 2011 order. While approving a $112.7 million electric rate hike, the PSC held the bill increase to zero for this year by extending the existing "competitive transition charge," and deferring recovery of some expenses to 2012 (Case 10-E-0050).

"The decision is unlikely to improve returns sufficiently, even with the help of our US cost reduction program and we expect to file for new rates as soon as practicable in 2012," Grid said in the earrings report.

Even so US operations earned 8.2% on equity for the fiscal year, up from 6.9% in 2009-10.

"We should be able to report further improvements in US returns in 2011-12," Bonfield added.

"The actions to improve the US results are clear and we are part way through the journey: rate case reviews, tough cost management, better customer service. The program is by no means complete and we have several more steps to go through before we can feel confident about long-term business performance …

"The current underperformance of our US business is an issue we have to fix. But we should not dismiss the potential for our US businesses to generate attractive returns for investors

FINANCE BRIEFS

Standard & Poor's Ratings May 17 downgraded the corporate credit rating and senior unsecured debt of **AES Corp.** from BB to BB- (S&P's third-highest speculative grade) and took it off CreditWatch–Negative after AES announced plans to obtain a $1.05 billion senior secured term loan facility to finance its all-cash bid for **DPL Inc.** S&P rated the new loan BB+. S&P and Platts are units of The McGraw-Hill Companies. S&P had warned when the $30/share deal — being entirely financed with debt — was announced April 20 that AES would be downgraded but said that would be when the deal closed. But **Moody's Investors Service** May 17 affirmed AES' corporate family rating and senior unsecured debt at B1 (Moody's fourth-highest speculative grade) and kept the outlook positive, because of the higher ratings on DPL (senior unsecured debt Baa1), which has been on review for downgrade since April 20. Moody's rated the new loan Ba1 (the highest speculative grade). S&P Directors Aneesh Prabhu and Marc Sonnenblick pointed out that while AES has projected improving financials that would support a BB rating, it has a history of failing to meet such forecasts. AES' common stock buyback programs are detrimental to bondholders and have increasingly influenced S&P's opinion of management's commitment to credit quality, they added. Moody's positive outlook reflects expectations the acquisition will reduce overall business risk, improve financial performance, increase the percentage of cash flow from regulated utilities and offset some of AES' business concentration in South America, said Vice President–Senior analyst Scott Solomon and Senior Vice President Angelo Sabatelle. AES could be upgraded if it shows sustained improvement in key parent level financial metrics such as the ratio of operating cash flow to debt, Moody's continued. AES aims to price the facility this week and close on it by June 6.

… Fitch Ratings May 17 downgraded **Black Hills**' issuer default rating from BBB to BBB- (the lowest investment grade), citing higher than expected leverage because of lower earnings from nonregulated energy marketing and coal mining operations, and higher debt to fund growth projects. Fitch also affirmed at BBB the IDR of utility **Black Hills Power**, which serves part of South Dakota, Montana and Wyoming. Their outlooks are now stable. This is Fitch's first action on Black Hills since it assigned ratings to the company October 15, 2008. Results tend to be volatile in energy (oil, natural gas and coal) marketing unit Enserco which lost money in the first quarter, and the coal mining unit has been impacted by rising costs while most of its contracts bar price hikes until 2012 or beyond, added Director Kathleen Connelly and Managing Director Glen Grabelsky. Fitch noted that Black Hills should benefit from when the 180-MW natural gas-fired Pueblo Airport plant being built by utility **Black Hills/Colorado Electric Utility** (which operates under the name **Black Hills Energy**) is added to rate base. At the same site, the **Black Hills Colorado IPP** unit is building a 200-MW gas plant with the output to be sold to the utility under a long-term power purchase agreement. This capacity is to replace a 300-MW contract with **Xcel Energy**'s **Public Service of Colorado** that expires December 31. On April 28 Colorado Electric filed with the **Public Utilities Commission** for a $40.2 million rate increase effective January 1, 2012, to reflect the new plant and PPA and other new infrastructure and expenses. In December the PUC approved retirement of the 42-MW W.N. Clark coal plant and granted a "presumption of need" for replacement capacity. On March 14 Colorado Electric filed for PUC approval of a third 90-MW Pueblo Airport unit.

… Xcel Energy May 18 raised the quarterly dividend on common stock 2.97% to 26 cents ($1.04 annually), the eighth straight annual raise but the smallest percentage increase in that time frame. The payout remains less than it was 11 years ago, because Xcel halved it to 75 cents in fourth-quarter 2002. Xcel and predecessor **Northern States Power** had increased the dividend for 26 straight years through Q4 2000, the last by 2% to $1.50. The new dividend is payable July 15 to shareholders of record June 23 and represents a payout ratio of 61.5% of reported basic earnings per share of $1.69 in the 12 months ending March 31, or 63.8% of "ongoing" EPS of $1.63. "The increase is consistent with our goal of growing the dividend 2% to 4% annually," said Chairman and CEO Richard Kelly in a statement. At the annual meeting earlier that day Kelly announced his retirement effective August 24 after 43 years with Xcel and predecessors **New Century Energies** and **Public Service of Colorado**. The board of directors elected President and COO Ben Fowke as Kelly's successor. He is to remain president. Xcel was formed with the August 18, 2000 merger of NSP and NCE, formed in August 1997 with the merger of PS Colorado and **Southwestern Public Service**. On May 19 the stock hit its sixth straight nine-year high at $25.34, the highest since $26.30 on May 9, 2002. The stock closed up 1.4% May 19 at $25.24, up 18.7% in a year and 38.3% in five years, but down 13% in 10 years. At that price the new dividend yield would be 4.1%.

comparable to those we should be able to deliver in the long run in the UK," he said.

"In some of the US jurisdictions we may need to be content to go through two regulatory filing cycles to ensure we've got the right frameworks in place to drive long-term value for our investors, and deliver the needs of our customers," Holliday said.

Improving US profitability is the focus of Grid's plan, announced January 31, to cut annual US operating costs $200 million by March 2012, mainly by cutting about 1,200 jobs by this summer.

Grid also announced a new operating structure with all of its US operations consolidated into one segment and new regional presidents appointed, all reporting to Tom King, president of National Grid USA.

— Paul Carlsen

RATES & REGULATION

Connecticut high court leaves intact state use of utility surcharge, but it may end anyway

A court ruling last week cleared the way for Connecticut to continue to channel money from a utility ratepayer surcharge into government coffers. But government officials may end the practice anyway.

The state Supreme Court rejected a challenge to the state's use of the surcharge, which was originally placed on ratepayer bills to pay back utility stranded costs, but now is used for eco-

nomic recovery bonds to balance the state budget.

The state has been under fire for using the energy industry to balance its state budget. Connecticut not only has been using funds collected from the utility surcharge, but also plans to tax generation.

The high court dismissed the surcharge case on a technicality. Senator Joe Markley, a Republican, who filed the legal challenge against the Department of Public Utility Control, said that even though he lost the court case he may have won the battle. Newly elected Governor Dan Malloy, a Democrat, and state lawmakers are now considering discontinuing use of the surcharge.

"This tax is as unsavory today as it was when enacted. I think we have served notice that we will resist such legislative skullduggery by any means available," Markley said.

Use of energy funds to cover state deficits is particularly controversial in Connecticut because the state has the second highest residential utility rates in the country. Hawaii is first.

The state's largest utility, Connecticut Light & Power, was ready to sunset the surcharge because it had served its purpose; the utility had recovered its stranded cost charges. But then-Governor Jodi Rell, a Republican, approved a plan last year to extend the charge and channel $700 million from it to back revenue bonds.

"We're glad the Legislature is trying to undo this inequitable tax from last session," said Katie Blint, CL&P spokeswoman. "We hope that the Legislature keeps on improving the situation as we go forward."

State officials are reconsidering use of the surcharge in part because the state may no longer face a $3.2 billion deficit, as originally forecast. Now the state may actually see a $509.6 million surplus, according to Kevin Lembo, Connecticut's comptroller. The state credits an improved business climate.

Lembo said that using the utility surcharge for the budget "is bad public policy" and with this year's unanticipated revenue, the state could end the practice.

But the rosier revenue picture is unlikely to change plans by the Malloy administration to impose a separate, new $72 million tax on generation, according to several sources.

Senator Kevin Witkos, a Republican, said there is still time in the budget process to modify the generation tax, but not likely time to get rid of it entirely. The budget has been approved in concept, but has yet to go before the Legislature for an "implementation" vote. When that vote takes place, lawmakers cannot get rid of the tax, but can modify how the $72 million is collected. Lobbyists for natural gas-fired generators have been pushing lawmakers to lower their share of the tax when the vote takes place, expected in a few weeks, he said. If they succeed, that would mean the tax will have to be raised for other forms of generation, so that the state can still collect the $72 million.

But Witkos said the administration is more likely to favor doing away with the utility surcharge and retaining the generation tax, since removal of the utility surcharge would mean a rate cut for utility customers.

Meanwhile, the tax faces a challenge from the Massachusetts Attorney General, who says it may unfairly increase rates throughout New England.

— Lisa Wood

Environmental group unveils Idaho energy plan as legislators move to update 2007 version

Hoping to help set the agenda for an update of Idaho's energy policy, the Snake River Alliance, an environmental group, proposed its own plan last week.

The Alliance criticized the Legislature for not accomplishing goals in the last update in 2007, and urged it to do more to encourage efficiency and reduce coal generation.

But the agenda for the 2011 review may have already been set during the debate over how much wind power utilities must buy under the Public Utility Regulatory Policies Act.

"I have a feeling that the committee will focus on wind and integrating those resources onto the grid," said Senator Curt McKenzie, Republican co-chairman of the Legislature's Interim Energy Committee, which is updating the state's energy policy.

The committee consists of legislators from the Senate and House and will likely begin meeting in July, McKenzie added.

The 2007 energy policy simply recommends it be revisited every five years, but does not give guidelines on how. McKenzie said that he and co-chairman Representative George Eskridge, a Republican, will have to figure out how to update the plan.

"The hardest part as co-chairs is to determine exactly what this process is going to look like," McKenzie said. But pointing not only to the debate over wind integration in his state, but also throughout the Northwest, he predicted the debate will focus on alternative energy, transmission, baseload generation and cost-effective integration.

The Public Utilities Commission has temporarily reduced the size of allowable qualifying facilities under PURPA from 10 MW to 100 kW while it reviews utility claims that adding more PURPA wind projects will raise rates. Bills that would have permanently limited the size of QFs did not pass.

While utilities say developers are building too much wind, the developers say utilities will only purchase wind when forced to via PURPA.

Eskridge expects the committee will examine state incentives for the wind industry.

The Alliance's energy plan calls on the state to encourage more wind, noting that almost half of the state's energy is imported, but acknowledges that wind farms must be sited properly.

McKenzie said that he also expects there will be some committee discussion of a state renewable portfolio standard. Idaho is the only state in the Northwest without one.

— Pam Radtke Russell

Oregon poised to drop 'phantom taxes' law and let PUC deal with issues in rate cases

A bill now awaiting Oregon Governor John Kitzhaber's signature would repeal the 2005 law requiring that utility rates reflect actual cash income tax payments, and let the Public Utility Commission again use its own judgment and deal with tax issues in rate cases.

Senate Bill 967 passed the state Senate April 20 and the House May 12. It would repeal S.B. 408, passed two years after a consumer group filed a complaint with the PUC charging that

Portland General Electric rates — calculated on a "stand-alone" basis —– covered "phantom" income taxes that then-parent Enron was not actually paying.

The City of Portland accused Portland General Electric of illegally boosting profits, but the utility, backed up by the PUC, responded that its income taxes were properly calculated and that the city and customer groups did not understand laws and regulations on tax deferrals and consolidated tax returns.

"No court has ever found that the rates the PUC set from 1997 through 2005 were illegal because income taxes were calculated using PGE's stand-alone tax liability consistent with long-standing policy," the PUC staff pointed out in a March 2006 report.

Nevertheless, for the past six years Oregon utilities have filed annual reports on amounts collected in rates to cover income taxes, and cash tax payments. If the difference is more than $100,000, the PUC must require a utility to adjust future rates with customers credited if the payments are lower than what is in rates, and charged if they are higher.

"For the past six years, ratepayers have been surcharged more than they have been credited," noted PUC spokesman Bob Valdez. "This simplistic approach didn't work … S.B. 967 turns back the clock."

Assuming Kitzhaber signs the bill, the PUC will again be able to deal with such complex issues in general rate cases "which are becoming an annual event around here," he added. The bill was developed with PUC and utility input.

"Application of the provisions of S.B. 408 can result in unusual outcomes, commonly termed the 'double whammy' effect," said PGE in its 2010 Form 10-K.

"If the company records higher actual operating income than forecast in its latest general rate case, customers are surcharged for the resulting increase in income taxes, further increasing earnings. Conversely, if the company records lower actual operating income than forecast in its latest rate case, customers receive refunds for the resulting decrease in income taxes, further decreasing earnings."

Avista Vice President of State and Federal Regulation Kelly Norwood noted that when the S.B. 408 process started it was unclear what the outcome would be.

"In the last several years there were more surcharges [to customers] than refunds. Most parties have realized this is not working out the way people thought it was going to. [Under SB 967] the PUC will still be able to look at all of these tax issues in each rate case and make sure it's fair to all sides," he said.

— Paul Carlsen

FORECASTS

Coal, gas prices, coupled with weak economy, boost coal power investment risk, Fitch says

A change in the relative prices of coal and natural gas have combined with a weak economy to increase the risk of investments in coal generation, Fitch Ratings said.

In "Paradigm Shifts: Taking the Steam Out of US Coal-Fired Thermal Power," Fitch said that natural gas prices have not been paralleling strong crude oil prices, while coal prices have remained firm, as China and India boost demand for coal to fuel electricity generators.

"Natural gas pricing, its relationship to oil prices, and the price of coal have shifted dramatically," the May 17 report said. "The current dynamics appear to have long-term implications and do not bode well for coal-fired generators."

The ratio of the cost of a barrel of crude oil, compared with the cost of the equivalent of natural gas in million Btu, remained about 7 to 1 from 1997 to 2006, but since then, that ratio has increased to nearly 25 to 1, the report states.

A similar ratio of the equivalents of coal and natural gas has increased from 8 to 1, in 2007, to 16 to 1 now, Fitch reports.

"Both changes are a result of the declining cost of natural gas and the increasing cost of its counterpart commodities, coal and crude oil," the report states.

Improved technologies to exploit shale gas resources has "altered the paradigm," Fitch reported, noting that the Energy Information Administration increased its forecast of US natural gas supply in its Annual Energy Outlook 2011 by 20% from its 2010 forecast.

US exports of coal to Asia increased by 240% from 2009 to 2010, Fitch notes, citing EIA data.

"Demand for electricity in emerging markets led by China and India has been increasing at substantial rates," the report states.

In comparison with Asian prices for oil and natural gas, coal is relatively cheap and available, and new coal-fired generation is "rapidly coming online" on the Asian mainland, the report said.

Meanwhile, US electricity generation fell by 4.1% in 2009, the largest drop in about 60 years.

"This pattern has continued through 2011 and, as a result, coal-fired generation, though still the leading source of electricity produced in the US, has fallen to the lowest level in history at 45% of US generation," the report said.

Based on these factors, Fitch has downgraded bonds for the following coal-fired generation plants:

- AES Eastern Energy's debt for five merchant power plants with 1,169 MW of capacity. The debt rating fell from "non-investment-grade speculative" to "extremely speculative." The power plants sell into the New York Independent System Operator; and
- Homer City Funding's debt for a coal-fired generation facility with 1,884 MW of capacity. The debt rating fell from "lower medium grade" to "non-investment grade speculative" with a negative outlook. The power plant sells into the PJM Interconnection.

— Mark Watson

Customers will have to pay to avoid meter concerns in Maine ... *from page 1*

to other utilities installing advanced meters.

Bangor Hydro Electric in Maine has fielded consumer inquiries about health concerns and wanting to opt out of its smart grid initiative (*EUW*, 16 May, 29), and there have been press reports about San Diego Gas & Electric and municipal utilities in Glendale, California, and other parts of the state dealing with

similar complaints.

Concerns about the health effect of radio frequencies from advanced meters have grown slightly, with utilities referring to small customer segments expressing those concerns and the overwhelming majority of customers showing no concern. Social media and press stories about consumer concerns can "amplify the voices of a vocal minority who raise fears and/or concerns and appear to be larger in numbers than they really are," said Patty Durand, executive director of the Smart Grid Consumer Collaborative.

In response to the concerns, utilities and smart grid advocates point to reams of data from the Federal Communications Commission, the World Health Organization, the Centers for Disease Control and Prevention, the Environmental Protection Agency and others that say emissions from advanced meters are below those from common household appliances.

Groups such as the EMF Safety Network, based in California, and the Smart Meter Safety Coalition in Maine assert that radio frequencies from advanced meters and their communication networks pose serious health, safety and environmental impacts. Those groups often point to material found on the Internet, not from government agencies, to back up their claims, said CMP spokesman John Carroll.

In its ruling, the Maine PUC emphasized that it supports advanced meters and does not believe they are unsafe. "I am a strong supporter of smart grid technology, " said Commissioner Vendean Vafiades.

But, she added, "it is important that people feel safe in their own homes and feel they have control over issues that they feel impact their health and welfare. I believe the customer should be able to make a subjective decision, not a decision that is either supported, denied or challenged by this commission."

Monthly charge of $12 would follow $40 up-front cost

The PUC said CMP customers can choose to not have advanced meters, but they must pay the costs associated with not being part of an advanced meter network.

It offered consumers two alternatives. Residential and small business customers may keep their existing analog meters for an initial charge of $40 and a monthly charge of $12, or choose a smart meter with the transmitter off for an initial charge of $20 and a monthly charge of $10.50. The fees would be cut 50% for low-income customers.

The meter with the transmitter off can still collect energy usage data just as any advanced meter does, but cannot transmit the information remotely, so the utility must go to the customer site and read the meter. Such a meter, however, has yet to be developed, CMP said, estimating that it could take up to nine months before the technology is available.

If utility customers for any smart grid project opt out and choose to have meters not be part of the advanced meter network, then accessing usage data, billing and communication systems would be very costly for those customers, and would defeat many of the benefits of smart grid efforts, smart grid advocates have maintained.

Besides paying the charges for opting out of advanced meters, another option for CMP customers is moving the meters to another location on their property at their own expense, said Commissioner David Littell. Vafiades warned, however, that moving a meter can be costly.

The PUC estimates that about 9,000 CMP customers will opt out. Carroll said it is hard to gauge if those numbers will hold now that customers will be asked to pay for the alternatives. The utility expects to complete the smart grid project by the first quarter of 2012, which will mean installing about 625,000 advanced meters. CMP already has installed about 200,000.

Elisa Boxer-Cook, a CMP customer who led the charge against advanced meters, called the PUC decision a "landmark" ruling. "I hope that it is precedent-setting, because I have over the past few months been getting calls from all over the country from people who have a smart meter and it is making them very sick, or it is interfering with their Wifi or appliances," said Boxer-Cook, who founded the Smart Meter Safety Coalition.

The commission ordered CMP to develop a communication plan to let customers know about the new options, and made decisions in two related cases. It dismissed a complaint that smart meters might cause fires and another that they might interfere with consumer electronics. The commission said that CMP and federal agencies have already addressed the issues.

CMP is pleased that the PUC resolved the different issues, said Carroll.

The largest utility in Maine, it jumped into the smart grid realm with the aid of about $80 million in stimulus funding from the Department of Energy.

Market, not utility, made wireless choice, CMP says

Carroll noted that the use of a wireless communication network for its smart grid project, which has attracted the brunt of the customer angst, was not a decision the utility made, but was the result of a request for proposals, with the only firms responding being wireless providers. "It was the only choice for us ... and the commission said it was appropriate" when it approved the broad smart grid project last year, Carroll said.

"We have always maintained that we had a commitment to the commission and the Department of Energy to execute the plan they approved and funded," he said. Carroll noted that because Maine is restructured and CMP is not a vertically integrated utility, the initial business plan for advanced meters was not cost-effective and would not have gained regulatory approval. The stimulus funding made all the difference, and "it put us on a path we would not have been on," he said.

The PUC approved CMP's broad smart grid plan in February 2010, then was prompted to rule on the opt-out proposal following consumer complaints. The utility expects

the overall project to cost about $191 million, with half of the costs being covered through the American Recovery and Reinvestment Act.

CMP estimated that if 1% to 2% of its customers opted out without being required to pay the cost of doing so, it would cost the utility as much as $70 million over the life of the program.

The order from the PUC "sets a great precedent" in that it sets the cost of opting out based solely on utility costs, said Dan Delurey, executive director of the Demand Response Smart Grid Coalition.

Further, with the dismissal of related safety and interference complaints tied to advanced meters, the commission "says we're done dealing with health effects" and other issues tied to radio frequencies from the meters, Delurey said. "That is important, and I think it will be something that other states will examine," he said.

The PUC decision should be viewed as a positive for other utilities, said Durand of SGCC, a collection of utility and smart grid firms formed last year to address consumer backlash against advanced meters.

In addition, "for those consumers who don't want a digital meter, I think it is a positive ruling for them to have choice, with the requirement that they pay for the added costs this choice necessitates," she said.

PG&E's costs are much higher than CMP

In California, PG&E has estimated that about 150,000 customers might be interested in not being part of the advanced meter network, utility spokesman Jeff Smith said. The company has about 10 million customers, and it has installed about 7.8 million advanced meters, some of which are natural gas meters, he said.

In its proposal, PG&E gave customers a "radio off" option, that would have the advanced meter installed but not transmitting data, Smith said. The utility laid out several options for tackling the cost, with an up-front charge of $270 and a monthly charge of $14. Another option is the same up-front charge, $270, but instead of the monthly charge, customers would have their rates increased, by 0.387 cents/therm for gas customers and 0.026 cents/kWh for electricity customers.

For a smaller up-front charge, $135, customers would face a monthly charge of $20, or rate increases of 0.532 cents/therm for gas customers and 0.036 cents/kWh for electricity customers, Smith explained. Low-income customers are eligible for a 20% discount.

For those customers who do not yet have an advanced meter and have health concerns while the opt-out proposal is being reviewed by state regulators, PG&E has established a "meter delay" list, to not install advanced meters for those customers, Smith said.

SGCC, which includes utility members, consumer advocates, smart grid vendors and consultants, is working to have utilities become more adept at sharing positive customer experiences with advanced meters, and it aiming to post such information on its website in June, Durand said.

She said she was not aware of any other states where utility customers have asked to not have advanced meters installed on their property.

— Tom Tiernan, Lisa Wood

EV charging issues to challenge utilities, Accenture says *... from page 2*

this point, commercial vehicle fleets will play an important role in broadening EV deployment as businesses move toward using more EVs in their fleets, Wynne said.

In the Accenture survey, 62% of the respondents would reject battery swapping, where depleted batteries are quickly swapped out and replaced at stations.

Accenture said those respondents prefer to plug in their vehicle to charge the battery, even though a large group of respondents also complain about long charging times for PEVs. Those two elements do seem contradictory, and they show both the immaturity of the EV marketplace and the unfamiliarity of the idea of battery swapping as a vehicle issue. Accenture, which has a large practice advising utilities on smart grid projects and new technologies, cautioned that about 70% of the respondents either said they needed to know more about EVs before making a purchase or did not understand them enough to make a purchase. The 30% that claimed to know enough to make a decision, however, "is higher than one might have expected, given that most consumers have not yet had a chance to consider purchasing a PEV," the study said. The recent launch of EVs from General Motors, Nissan and Renault may have played a part in that perception, Accenture said.

About 85% of those in the study said PEVs have insuffi-

cient driving rate to cover their daily driving habits, and 70% think charging times for PEVs are too long, with a majority preferring PHEVs compared with PEVs for an electric vehicle purchase. The battle between PEVs and PHEVs will not be determined solely by technology, but by consumer preferences, and "if consumers prefer not to charge the way they run and manage their cars, the popularity of dual-fuel PHEVs could hold back the adoption" of PEVs, Accenture said.

"As drivers get behind the wheel, they may become more open to fully electric vehicles and battery swapping services. But denser charging networks and fast charging units will be required if utilities want to drive up demand" for PEVs, Matias Alonso, global managing director for utilities at Accenture, said in a statement.

Addressing the PEV vs. PHEV distinction, Wynne said the extended range of PHEVs may play an important role with some consumers, but 75% of the US population commutes 40 miles or less each day, meaning they could have a PEV meet the vast majority of their driving needs.

Among the different countries, consumers in China and Italy showed the strongest preference for having EVs replace conventional cars over time, with 86% and 76%, respectively, supporting that notion. The US and Japan, home to many automakers, showed less support, at 46% and 45%, which was higher than only the Netherlands among the 13 countries in the survey. The varying preferences may support Accenture's view that the automotive industry is headed toward a mixed landscape of various fuel technologies, rather than migrating toward only EVs, the company said.

As demand for electric vehicles grows, so will the opportunities for charging station manufacturers, Wynne said in an email on the Accenture study. He referred to data from Pike Research, showing that the global EV charging station market in 2010 was nearly $70 million, and is expected to reach more than $1 billion by 2013.

Legislation debated in Senate hearing

In Washington last week, lawmakers and utility industry representatives urged the Senate Energy and Natural Resources Committee to support two bills that would aid deployment of EVs.

One bill (S.948), introduced by Oregon Democrat Jeff Merkley and Tennessee Republican Lamar Alexander, who drives a PEV Nissan Leaf, would provide up to $3 billion over five years for grants to selected communities to build charging stations and support converting commercial vehicle fleets to EVs. The other bill (S.734), introduced by Michigan Democrat Debbie Stabenow, calls for boosting federal research within the Department of Energy on EVs and other alternative fuel vehicles.

Patrick Davis, director of DOE's Vehicles Technology Program, testified at the Senate hearing that DOE is still evaluating both bills and did not have a position on them.

Seifi Ghasemi, chairman and CEO of Rockwood Holdings and a member of the Electrification Coalition, said increased consumer demand for EVs will prompt automakers to boost production of the vehicles, and spur charging infrastructure to support more vehilcles. "The rate of production of the vehicles will increase as consumers demand it, and consumer demand will increase if the infrastructure is in place," he said.

— Tom Tiernan, Herman Wang

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Register by August 5, 2011 and SAVE $300

Platts ***2011 Transmission Planning & Development*** *Forum* explores the relevant issues, concerns, and new ventures in transmission expansion.

FERC Commissioner Marc Spitzer Delivers Keynote Address

Interactive Discussions from Leading Industry Professionals that Examine:

- State and federal regulatory issues
- How federal court rulings have affected cost allocation and siting
- Eastern Interconnection States Planning Council
- Transmission construction concerns and challenges
- Right of first refusal
- Transmission planning within RTO/ISO
- Regulated and merchant financing challenges
- Transmission planning in markets around the world

Spealers to Include:

- *Lauren Azar,* **Public Service Commission of Wisconsin**
- *Timothy A. Simon,* **California Public Utilities Commission**
- *Donna Nelson,* **Texas Public Utilities Commission**
- *Ann Berwick,* **Department of Utilities, Commonwealth of Massachusetts**
- *Jay Caspary,* **Southwest Power Pool**
- *Jennifer Curran,* **Midwest ISO**
- *Mark Sims,* **PJM Interconnection LLC**
- *Frank A. Wolak,* **Stanford University**

Additional speakers and the Champlain Hudson Power Express case study…

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For a complete agenda, more information, or to register and SAVE $300 please visit us online at **www.transmission.platts.com** or call us at 866-355-2930 (toll-free in the US) or 781-430-2100 (direct).

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