

Electric Power Daily

Thursday, June 30, 2011

Michigan grants air permit to 600-MW Wolverine coal plant

In a ruling some billed as a triumph of process over ideology, Michigan regulators on Wednesday approved a final air permit for Wolverine Power Cooperative's 600-MW coal-fired plant proposed for Rogers City.

The permit not only ended, for the moment at least, a tortured journey for the project, but marked what appeared to be the first instance of "best available control technology" determination for a power plant's greenhouse gas emissions, under the GHG requirements the Environmental Protection Agency put in place in January. The DEQ concluded BACT for the plant was use of 5% biomass to fuel the boilers, and energy efficiency measures such as installing variable speed motors.

The permit calls for limiting GHG emissions to 2.1 pounds/kWh from each of the project's two 300-MW circulating fluidized bed boilers and to about 6 million tons a year from both units.

The Department of Environmental Quality's decision reversed a year-ago ruling
(continued on page 6)

NV Energy cannot delay on renewable transmission plan: PUC

NV Energy's request that the utility be allowed to wait before presenting its renewable transmission initiative proposal for commission review as part of its resource planning process was unanimously rejected Wednesday by the Nevada Public Utilities Commission.

At issue is a tentative proposal by NV Energy to build up to 537 miles of transmission lines to allow renewable generators to deliver power inside Nevada and to California and other Southwestern markets. The proposal will likely change, depending on how much market interest it generates. NV Energy wanted to wait until it knew the final scope of the initiative before beginning its review under the state's resource planning rules.

PUC staff, the commission's general counsel and the Nevada Bureau of Consumer Protection urged the PUC to reject NV Energy's request for a waiver from the resource planning rules, partly over ratepayer protection issues.

One of the key questions surrounding the transmission initiative, unveiled last
(continued on page 7)

Siemens and Cape Wind in talks on financing offshore project

Siemens Financial Services is in "preliminary discussions" with Cape Wind over possible means of financing a portion of the offshore wind facility.

Jillian Lukach, a spokeswoman for the financial services arm of the big German energy equipment manufacturer that is already slated to supply the 130, 3.6 MW turbines that are to be installed in Nantucket Sound 7 miles off the coast of Cape Cod, Massachusetts, confirmed on Wednesday that Siemens Financial Services is looking at ways to provide some of the financing for the estimated \$2.5 billion, 468-MW project, but would not offer any further details.

Cape Wind director of communications Mark Rodgers on Wednesday also confirmed the discussions, and said Cape Wind is "pleased that Siemens has expressed an interest in playing this role."

Cape Wind, like a number of other Atlantic Coast offshore wind projects, has been suffering from the absence of financing. The project has received permits and

OG&E smart grid pilot shows consumer response, savings

The financial savings and load shifting taking place at Oklahoma Gas and Electric's smart grid pilot project are limited at the moment, but OG&E has big plans to tap into the home energy management space to meet its resource needs, officials said this week.

OG&E is putting federal stimulus funding to work beyond advanced meters, through dynamic pricing options, in-home displays and programmable thermostats that have most participants responding to price signals. With the help of Energate and Silver Spring Networks providing communications and smart grid technologies, "we're on a journey with our customers" to make them more aware of their energy usage and ways to save money, said Sandra Longcrier, manager of marketing for OG&E's smart grid program.

Nine out of ten customers in the pilot have saved money compared with the utility's
(continued on page 7)

FERC urged to alter parts of reporting NOPR

A variety of changes, including the exclusion of certain types of deals, should be made to the Federal Energy Regulatory Commission's proposal to refine its reporting requirements and make large municipal utilities, cooperatives and federal power authorities report electricity and transmission transactions, trade associations and the Bonneville Power Administration said Tuesday.

While opinions varied on just what in the notice of proposed rulemaking needs changing, the trade associations were united in their protest against the commission's plan to require electronic tag identification data on deals in all electric quarterly reports, or EQRs.

The trade associations are very concerned that mandatory e-Tag reporting in the EQRs will cause more of a burden than the information is worth, said joint comments by the American Public Power Association, Edison Electric Institute, Large Public Power Council and the National Rural Electric Cooperative Association.

"There is no simple one-to-one relation
(continued on page 8)

leases and has a power purchase agreement for half of the projected power, but no financial backing.

National Grid has signed a 15-year power purchase agreement for 50% of Cape Wind's output at 18.7cents/kWh, a price that is to escalate at 3.5% a year. Some critics of offshore wind power point to its cost as the reason none has been built in the US, compared to the 41,000 MW of wind power that has been installed onshore in the US.

Without financing, Cape Wind has not been able to schedule a construction start-up of the project. It was the Department of Energy's conclusion in May that because it did not have financing that the project would miss a critical September 31 construction start-up deadline that is a criteria for receiving a DOE loan guarantee.

It is unclear just what type of financing, and how much, that Siemens may be willing to offer Cape Wind.

— Jeffrey Ryser

BLM segregates land in West for solar potential

About 677,000 acres of federal land in six Western states will be off limits to new mining claims for the next two years while federal officials continue evaluating the potential to use those areas as "solar energy zones," where renewable projects would be expedited, the Bureau of Land Management said Wednesday.

BLM, a unit of the Department of Interior, will publish a notice in today's *Federal Register* segregating 24 tracts of land for two years under a temporary, interim rule implemented in April aimed at blocking new mining claims in order to spur development of solar and wind energy projects.

The segregation does not affect existing mining rights, BLM said.

The tracts cover zones BLM identified in its draft programmatic environmental impact statement for solar energy as priority areas to develop such projects. The zones are in Arizona,

California, Colorado, Nevada, New Mexico and Utah.

A two-year segregation of those lands implemented as part of the PEIS preparation expires today, and the notice prevents new mining claims from being filed in those areas while BLM continues to study their suitability for solar development.

BLM in April published a *Federal Register* notice proposing segregating the solar zones for five years, and is continuing work on an environmental assessment for the longer-term segregation, it said.

"Taking the time to fully evaluate these lands for their large-scale solar potential will identify those that are most appropriate for solar development and that have limited conflicts with wildlife or other resources and land uses," BLM said.

"Through coordinated environmental studies and responsible landscape-scale planning decisions, the BLM is facilitating accelerated solar energy production that will help build a clean energy economy for America," it added.

BLM will now finalize a permanent segregation rule that would allow it to prevent new mining claims on land where rights-of-way applications for solar or wind projects have been filed or are likely to be filed.

Mining industry groups have said such a rule would go too far in interfering with their property rights, and have asked BLM to abandon or significantly scale back the rule.

— Nick Juliano

FERC approves Hudson interconnection

Against the wishes of New Jersey energy regulators, an interconnection agreement for the Hudson transmission line running into New York City has been approved by the Federal Energy Regulatory Commission.

FERC on Tuesday said reliability concerns raised by the New Jersey Board of Public Utilities are beyond the scope of the proceeding, which involves the interconnection agreement between Hudson Transmission Partners, Consolidated Edison

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Electric Power Daily is published daily by Platts, a division of The McGraw-Hill Companies. Registered office Two Penn Plaza, 25th Floor, New York, NY 10121-2298

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and the New York Independent System Operator.

“The NJ commission did not object to the proposed material deviations from NYISO’s pro forma [large generator interconnection agreement] reflected in the interconnection agreement at issue here and, instead, as noted above, raises matters beyond the scope of the instant proceeding. Therefore, we find no basis for us to not accept the interconnection agreement as filed.”

According to the order, the deviations from the pro forma agreement were modifications reflecting that Hudson is a merchant transmission project and not a generating facility.

The BPU had filed a protest, saying interconnection of the underground and underwater line to transfer 660 MW of capacity to New York City would make the power permanently unavailable to northern New Jersey and the rest of the PJM Interconnection, exacerbating northern New Jersey’s already tight supply situation (Docket No. ER11-3479). The BPU had said its reliability concerns were worsened by FERC’s upholding of PJM’s elimination of an exemption for state-sponsored generation projects from PJM’s minimum offer price rule. That decision impedes New Jersey’s ability to foster new generation resources, the BPU said.

The high-voltage direct current line would connect the Bergen substation in New Jersey owned by Public Service Electric & Gas with Con Ed’s West 49th Street substation in New York City. According to the April 29 application for approval of the interconnection agreement, power would flow in one direction from New Jersey to New York.

The project is being developed by PowerBridge of Fairfield, Connecticut, through Hudson Transmission Partners. PowerBridge principals also developed the Neptune Regional Transmission System, which runs 65 miles between PJM and Long Island.

FERC on April 29 approved Hudson’s March 3 request for negotiated rate authority for the line, which has commenced construction.

— *Jason Fordney*

West to sync up for intra-hour transactions

Within weeks, the majority of the West’s power and transmission providers will all be operating on the same schedule as they implement a new, standardized business practice to facilitate intra-hour transactions.

“It’s a pretty exciting product,” said JJ Jamieson, regional liaison at Portland General Electric. “It’s definitely going to make what we do much quicker than it has been traditionally.”

Such synchronization is rare for the region comprised almost entirely of bilateral markets. It comes as the result of work by the Joint Initiative — a coalition of Western power entities headed up by WestConnect, Columbia Grid and Northern Tier Transmission Group — that has been developing tools for better integrating variable resources.

The Western Interconnection encompasses most of the US states west of the Continental Divide, as well as the Canadian

provinces of Alberta and British Columbia, and part of Baja Mexico. The Joint Initiative’s tools are being utilized by most stakeholders there, with the exception of the organized markets of the California Independent System Operator and the Alberta Electric System Operator.

Those tools include the Dynamic Scheduling System for variable resources, currently wrapping up trials; the intra-hour transaction accelerator platform for bilateral trades, which will go live around October; and the intra-hour business practice.

The deadline for getting the business practice in place is officially July 1, but some transmission providers are ahead of schedule and have already implemented them, and others will make good in the next couple of weeks.

Once fully implemented, the business practice will essentially enable complicated incremental or decremental transactions between balancing authorities every 30 minutes — the first time the West as a whole has been able to do intra-hour transactions.

Market participants believe the ability to schedule broadly at half-hour intervals will help integrate renewables by allowing more frequent and accurate generation forecasts and the ability to better direct output to match demand.

And without the business practice in place, expensive, and at times prohibitive, seams issues arise when power schedules are sent across balancing authority borders.

“It really simplifies the process for a scheduler because you don’t have to guess whether or not your schedule will go all the way through,” Jamieson said.

Charles Reinhold, one of the joint initiative’s facilitators and a project manager at WestConnect, said the transmission providers and power producers he has talked to are enthusiastic about the added flexibility. It will also allow participants to do half-hour transactions with the California Independent System Operator’s markets, a major consumer of power produced in the rest of the region.

However, even as the West moves forward with this answer to intra-hour trades, it remains to be seen whether the Federal Energy Regulatory Commission will require the region to develop intra-hour trading at 15-minute intervals to further integrate variable resources.

In November, FERC issued a notice of proposed rulemaking (Docket No. RM10-11) that, among other things, indicated the commission may require public utility transmission providers to offer 15-minute scheduling in order to better and more accurately integrate renewables such as wind and solar into the grid.

Earlier this year, some members of the joint initiative effort expressed concern about the NOPR during a conference call related to the joint initiative.

One Joint Initiative member said FERC “is acting like putting in the 15-minute scheduling will solve all the problems, and it actually creates a lot of problems.”

There is no estimate on when or if the commission will issue a final decision. “The rumor on the street is [the requirement] will be 15 minutes, rather than 30, when a final ruling does come out,” Reinhold said. He did not say how market partici-

pants could accomplish that if it is mandated.

— *Hilary Costa*

Enernoc seeks amendments to Maryland contracts

Energy management company Enernoc has not been able to provide the capacity resources it agreed to supply under contracts with three Maryland utilities, the company said in filings asking the Public Service Commission to amend the agreements.

The company has contracts with Pepco, Delmarva Power and Potomac Edison to provide a certain amount of capacity resources for demand response and interruptible load under agreements signed in March 2009.

The agreements were signed in response to “gap request for proposals” required by the PSC when in November 2008 it ordered the utilities to procure demand response resources to help close a projected shortfall in peak demand resources beginning this year.

At that time, the PSC said the Mid-Atlantic region was facing a peak demand shortfall between 2,600 MW to 3,000 MW by 2011. Between 600 MW to 690 MW of the gap was expected in Maryland, the PSC said.

Enernoc redacted from the filing the amount of megawatts it was required to provide the utilities, and the amount it fell short; however, it noted in the filings that the total amount procured by the state’s four utilities was about 400 MW.

“As of May 31, 2011, despite its best efforts, Enernoc did not obtain the requisite capacity resources for the 2011-2012 delivery year,” Enernoc said in the filings. The deadline for enrollment for the 2011-2012 delivery year was May 31.

Enernoc had three problems attempting to contract with new customers for the 2011-2012 delivery year, the company said. There was substantial competition from other providers offering demand response services, certain end-users had generator permitting issues that were not resolved in time to be enrolled in the 2011-2012 delivery year and some end-users had internal procurement policies that did not allow for a decision to be made in time for enrollment in the 2011-2012 delivery year, Enernoc said.

“While competition will continue going forward, the other two issues can be expected to be resolved in time to enroll additional customers for the 2012-2013 delivery year,” Enernoc said. The company is confident with 11 months before the 2012-2013 delivery year deadline it can fulfill its obligations to Pepco and Potomac Edison, but it asked that the obligation to Delmarva Power be reduced. “Enernoc believes this reduced capacity amount reflects a realistic assessment of the remaining potential for demand response resources that it can enroll from the Delmarva territory,” the company said.

Enernoc proposed two modifications to the agreements, including allowing capacity resources proposed for the 2011-2012 delivery year be interruptible load for reliability resources or demand response resources.

The change addresses the requirement that only inter-

ruptible load for reliability qualifies to meet the terms of the contract. The ILR and demand response products “are identical demand response products from a performance perspective,” Enernoc said. The only difference is that ILR resources are registered annually, while demand response obligations must be obtained through participation in either a base residual auction or incremental auction, Enernoc said.

With that change, Enernoc would still be short of its targets, the company said.

Enernoc also asked that the total megawatts for the overall term of the contract be broken down into specific requirement for each of the four years of the contracts.

The shortages will not affect system reliability, Enernoc said, noting that the PJM Interconnection has determined that it expects adequate resources this summer to meet demand in the region. The changes in the contracts also would not impose additional costs on ratepayers, the company said.

In spite of the shortages, the Maryland Gap RFP is achieving its policy objectives of helping to bring more demand resources to the state, Enernoc said.

Potomac Edison authorized Enernoc to say that it does not oppose the amendments to the agreement, but Pepco Holdings, Pepco and Delmarva Power’s parent company, declined to take a position on the proposed amendments, Enernoc said.

Neither Enernoc nor Pepco Holdings returned calls for comment by press time.

— *Mary Powers*

NCUC approves cost deferral on Duke scrubber

The North Carolina Utilities Commission, in an unusual move, approved Duke Energy Carolinas’ request to defer accounting for more than a year incremental costs associated with a \$583 million scrubber project at Duke’s Cliffside coal station.

While NCUC “historically treated deferral accounting as a tool to be allowed only as an exception to the general rule,” in this case it should be approved because the dollar amount is significant, because Duke’s rate of return on equity will remain below the allowable 10.7% level even with the deferral and because not allowing deferral could harm Duke’s access to capital markets, NCUC said in its Wednesday order.

Duke last November asked NCUC to let it defer in a regulatory asset account until new base rates are put into place certain incremental costs the utility incurs at the new scrubber at its 562-MW Cliffside-5 coal unit in Rutherford County.

The scrubber, whose installation was required under North Carolina’s Clean Smokestack Act, became operational October 12. Duke notified the NCUC June 1 that it soon plans to file for a base rate increase that would include the scrubber’s cost and become effective on or about January 1. The incremental costs Duke asked to defer include scrubber-related depreciation, cost of capital, property taxes and related non-fuel operation and maintenance expenses.

If its request for deferral were denied, Duke said it would

see a \$128 million reduction in its earnings. Duke expects its actual rate of return on equity in 2011 to remain below its NCUC-authorized 10.7% even if the deferral is approved. Duke also reminded the commission that it plans to make significant additional investments in environmental controls and new generating capacity over the next few years, and that approving the deferral request would enhance its ability to attract the capital it will need.

Duke is building Cliffside-6, an 825-MW coal unit expected to begin commercial operation next year, as well as 620-MW, natural gas-fired, combined-cycle units at its Buck and Dan River stations. The Buck unit will come online later this year and the Dan River unit in 2012.

In its ruling, the NCUC said that deferred accounting's use "has been allowed sparingly ... due in part to the fact that [it] typically provides for the future recovery of costs for utility services provided to ratepayers in the past." The commission added, "the longer the deferral period, the greater the likelihood that ratepayers who are ultimately required to pay rates including the deferred charges ... may not be the same ratepayers who receive the services."

Further, the NCUC said it also has been reluctant to allow deferral accounting because it typically equates to "single-issue ratemaking for the period of deferral, contrary to the well-established, general ratemaking principle that all items of revenue and costs germane to the ratemaking and cost-recovery process should be examined in their totality."

The NCUC acknowledged, however, that in the past it has allowed deferred accounting in rare instances — such as following the start-up of new, expensive generating units — "where there was a clear and convincing showing that the costs were of an unusual and/or extraordinary nature and that, absent deferral, would have a material impact on the company's financial condition."

The commission said it will permit Duke to defer the incremental costs associated with the Cliffside-5 scrubber until December 31, or when its new base rates become effective, whichever is earlier. But if for some reason Duke does not file for new base rates by the end of this year, it said, the utility would be required to amortize the deferred costs over a 36-month period beginning January 1.

Duke spokesman Jason Walls said that the utility welcomed the NCUC's ruling. "It's an accounting treatment that transfers the costs from when the scrubber was 'used and useful' to when the new base rates are implemented," Walls said.

— *Housley Carr*

Calif. project will withstand challenge: developer

A subsidiary of Houston-based Macquarie Energy expressed optimism Wednesday that its proposed 600-MW natural gas-fired power plant in California's San Joaquin Valley will advance, despite a legal challenge.

The Environmental Protection Agency in May issued a

permit to the \$530 million project, sparing the plant from complying with limits on greenhouse gases, sulfur dioxide and nitrogen dioxide adopted after the permit application was filed in February 2009.

The EPA's move came a day after US District Court Judge Richard Leon ordered the agency, which has been evaluating the project for about three years, to make a final decision by August 27.

Macquarie subsidiary Avenal Power Center sued the EPA in 2010, saying the agency violated a one-year statutory deadline for permit review.

In a "petition for review" filed Monday with the EPA's Environmental Appeals Board, the Sierra Club and Communities for a Better Environment said EPA needs to comply with the federal standards in effect when the permit was issued.

The San Joaquin Valley is one of the most polluted regions in the US and communities near the Avenal project already experience NO2 exposure near federal limits, the environmental groups said, adding that EPA is ignoring the fact that, "simply put, this is the wrong project in the wrong location."

"Congress is pretty clear about what you need to do to get a permit and the EPA is trying to find a way around that," said Earthjustice attorney Paul Cort. Granting the permit would encourage other project applicants to seek similar treatment from the EPA, Cort said.

Frank Wilson, an Avenal Power Center spokesman, said the developer does "not see anything in the petition to cause us the believe" that the EPA would not allow the project to advance. The technology used at Avenal meets and exceeds local and state requirements for emissions of greenhouse gases and NO2, Wilson said.

Wilson said Avenal does not believe the legal challenge will increase the cost of the project. But until the board rules, it unclear whether the time line for construction will be affected.

— *Lisa Weinzimmer*

Utility output drops 7% on year in week: EEI

Utilities generated 83,237 GWh in the week that ended June 25, 7% below the 89,513 GWh generated in the corresponding week of 2010, the Edison Electric Institute said Wednesday.

The weekly total was 2,153 GWh above the 81,084 GWh produced in the week that ended June 18, EEI said.

Output fell in six of the nine regions EEI assesses, the second week in a row that has been the case.

The largest drop was in New England, where generation fell 14.2% to 2,462 GWh. The next biggest drop was in the West Central region, with a fall of 13.2% to 6,246 GWh.

Two other regions also saw double-digit decreases — the Mid-Atlantic and the Central Industrial region — while output in the largest region by generation, the Southeast, fell by 9.4% to 22,327 GWh.

Output rose in the remaining three regions, with the Pacific

Southwest seeing an increase of 6.2% to 5,686 GWh, followed by the Pacific Northwest with an rise of 1.3% to 2,745 GWh. The Rocky Mountain region saw an increase of only 0.5%, to 5,672 GWh.

Utility generation in the first 26 weeks of 2011 was 1.962 million GWh, 0.1% below the 1.964 million GWh in the same period of 2010, EEI said.

The numbers are based on generation from investor-owned utilities, cooperatives and government-owned utilities.

— *Keiron Greenhalgh*

Michigan grants air permit ... from page 1

by the same agency to deny the Cadillac-based generation and transmission co-op's application for the controversial \$2 billion baseload project.

The difference in the outcomes? DEQ in 2010 was under the administration of former Governor Jennifer Granholm, a Democrat and outspoken champion of renewable energy resources such as wind and solar. Under her watch, the Legislature passed a comprehensive energy law that imposed the state's first renewable portfolio standard requiring utilities to get at least 10% of their power from renewables by 2015. In a February 2009 executive order, Granholm directed state agencies, including DEQ and the Public Service Commission, to weigh whether a new coal plant was "needed" before green-lighting an application.

Granholm wrapped up her eight years as the state's chief executive in December and was barred by Michigan law from seeking re-election. Republican Governor Rick Snyder, a former businessman who rode a statewide GOP surge into office last November, has sent out his own directive to state agencies about how to handle the regulatory process, according to DEQ spokesman Brad Wurfel.

"Our directive over here, with the Snyder administration, is threefold: We work to be stewards of the environment, full partners in business development in Michigan, and we work towards the best customer service all the way around," he said. "We've got an obligation to protect the environment, but we also have an obligation not to impede business development in this state."

In the Wolverine case, Wurfel said the agency's protocols were "simple and straightforward, as they should be. When this permit was denied, it was with a needs process that was a deviation of what DEQ normally does. Absent that, the permit was compliant with state and federal clean air laws then, as it is now. This isn't about an ideology, it's about process. And it should be a straightforward process."

Following last year's permit denial, Wolverine filed a legal appeal. On January 28, Judge William Fagerman of Missaukee County Circuit Court ruled DEQ "exceeded its authority" in turning down the permit on the basis of need. His opinion came on the heels of a similar verdict handed down late last year by Judge Jon Van Allsburg of Ottawa County Circuit

Court. He also held the agency improperly rejected an air permit for a 78-MW coal plant proposed by the Holland Board of Public Works.

In February, DEQ awarded the permit to Holland. The Sierra Club and Natural Resources Defense Council, in an appeal filed in Ingham County Circuit Court, are seeking to overturn the permit.

Anne Woiwode, the Sierra Club's state director in Michigan, said her group was disappointed with the latest Wolverine decision and is considering its options, including more litigation. Woiwode said she was "puzzled" by the Snyder administration's governing philosophy. "These are not logical decisions based on what the Snyder administration claims it wants for Michigan," she said, accusing the administration of "abandoning one of the fastest-growing sectors in the country by not supporting clean energy. Putting anchors around the necks of communities in the state with old, unneeded power plants is really irrational if you're concerned about the economic well-being of the state."

She added: "Unfortunately, the Snyder administration's energy policy is non-existent, and they are driven more by lobbying efforts than by a coherent view of Michigan's future."

But the Mackinac Center for Public Policy, a Michigan-based free-market/libertarian think tank, believes the DEQ got the Wolverine decision right this time.

The agency's statutory duty is to "adjudicate those applications based on whether the power plants meet all requirements of the Clean Air Act," said Russ Harding, the group's senior environmental policy analyst. "When they do that, it should be an up-or-down decision not based on ideology. What was happening in the Granholm administration is she was asking the DEQ to make those decisions based on ideology."

Whether Wolverine actually moves forward with construction on the coal plant remains uncertain. Woiwode said she has heard Wolverine might be having second thoughts about making a final commitment to the expensive project. "We're hearing that Wolverine is seriously looking to not pursue the project," she said.

Wolverine spokeswoman Nancy Tanner said the co-op was pleased with the DEQ's action and was "evaluating the conditions included in the final version of the permit." She said that while approval of the permit is "a significant milestone," Wolverine "still has more work to do, including a thorough financial and rate evaluation and a decision by our board of directors on whether to proceed with the project." She did not indicate when a final determination would be made.

Although Wurfel said he was not aware of Wolverine's intentions, he offered an analogy: "Just because you get a permit from the BMV [Bureau of Motor Vehicles] doesn't mean you get a car."

But if the permit is challenged in court, he said, DEQ is "prepared for that eventuality."

— *Bob Matyi*

NV Energy cannot delay ... from page 1

month, is how it would be paid for. Earlier this month, Nevada Governor Brian Sandoval, a Republican, vetoed a bill that would have allowed renewable transmission lines that are built to export power be included in the state's resource planning process and eligible for ratepayer cost recovery. Currently, Nevada's resource planning rules do not cover lines built to serve out-of-state customers.

PUC staff and BCP pointed to Sandoval's veto, which focused on the need to protect ratepayers, as a reason to begin reviewing NV Energy's proposal.

NV Energy has started the permitting process for the project, a move that triggered a requirement that the utility ask the PUC for an environmental permit for the project. However, the Las Vegas-based utility does not yet know the exact scope of the project, or even if it will be built. NV Energy this month started a planning process for the project designed to determine renewable generator interest in the lines.

The PUC's general counsel recommended against granting the waiver, partly because it believed the utility had not adequately explained why a delay made sense. "The resource planning process is meant to allow the commission to review and approve or reject proposed construction prior to the utility incurring costs related to the proposed construction," the general counsel said. "To grant this petition and allow a delay in the commission's review could result in a situation in which this transmission is deemed unnecessary down the road, and either ratepayers or shareholders must bear the costs."

The BCP was also concerned about ratepayer costs. Nevada law does not allow NV Energy to build power lines that do not serve its customers, according to the BCP. "The commission should not waive the resource planning requirements — particularly in relation to proposed transmission line construction that has some potential to increase rather than 'contain' customer rates," BCP said in a PUC filing.

NV Energy argued that it was required by the Federal Energy Regulatory Commission to build transmission to allow generators to interconnect with its system.

BCP disagreed. "BCP contends that there is a substantial difference between a utility's obligation to connect requesting customers to the existing transmission system and a proactive proposal to invest [\$1 billion] in speculative facilities specifically designed to provide renewable energy to customers in other states," BCP said. "NVE is stretching federal obligations beyond the point of reasonableness."

In the wake of Sandoval's veto, NV Energy spokesman Mark Severts declined to discuss how the governor's action would affect the transmission initiative or how the lines might be paid for.

The PUC Wednesday also opened an investigation into NV Energy's renewable transmission initiative to have a venue for openly discussing the proposal.

Terra-Gen geothermal project

Meanwhile, Terra-Gen Power this week asked the PUC for an environmental permit for its planned 70-MW Coyote Canyon geothermal project, which is under a fast-track review by Bureau of Land Management. Terra-Gen, an affiliate of ArcLight Capital Partners and Global Infrastructure Partners, plans to build the project near Fallon, Nevada. The project would interconnect with a 230-kV line that runs 211 miles between Terra-Gen's 60-MW Dixie Valley geothermal plant and a substation near Bishop, California.

Terra-Gen is also developing the 62-MW New York Canyon project near Lovelock, Nevada. The project is under a fast-track BLM review. The fast-track review was designed to allow advanced-stage renewable projects meet eligibility deadlines for federal financial incentives.

New York-based Terra-Gen owns 1,556 MW of geothermal, solar and wind capacity.

— Ethan Howland

OG&E smart grid pilot shows ... from page 1

standard rates, which are about 9 cents/kWh, Longcrier said.

OG&E's pilot that began last summer involved 3,000 customers, split evenly between a time-of-use rate with a critical peak pricing element, and a variable peak pricing plan, she

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FIELD REPORT #5	
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Location	Worldwide

The context has changed, not the fundamentals

Since March 11, much has changed, but much remains the same: we still must meet growing energy demand while limiting greenhouse gas emissions. That means producing massive affordable energy in a balanced

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explained in an interview. The TOU rates are 4.2 cents/kWh during off-peak periods and 23 cents/kWh during on-peak periods, with a limited number of critical peak pricing events when peak prices are 46 cents/kWh.

The variable peak pricing plan changes daily, with customers notified a day ahead of time in a manner they choose, such as email, text message, phone calls or websites, Longcrier said. The four different levels in the variable pricing plan are about 4.5 cents/kWh for low demand periods, 11.3 cents/kWh when demand is higher, 23 cents/kWh at peak demand periods and 46 cents/kWh during critical demand events. OG&E called critical pricing events 11 times last summer, she said.

Consumers taking part in the pilot, which was increased to 6,000 customers this summer, have been satisfied, and “we’re very impressed with our customers’ willingness to adjust their usage” to either save money or provide more comfort for their lifestyles, she said.

Participants achieved a peak load reduction of 1.92 kW/home, representing a peak demand reduction of more than 50%, surpassing the goal of 1.3 kW/home, Energate and Silver Spring reported this week. But the broad energy savings will start once OG&E ramps up the program next year to help it meet its peak demand reduction goals, Longcrier said. The utility has committed to reduce demand 70 MW by the end of 2012, and 210 MW by the end of 2014 to avoid the need for new power plants.

While scaling up the plan on a utility-wide basis is still being discussed at OG&E, “if we can get 20% of our customers on time-based rates like this, and of that 20%, if they can shift 20% of their peak demand, we’ll meet our goal,” she said. The time-based rate program will be used in combination with load curtailment and demand response plans for larger customers, she said.

OG&E is one of the 100 utilities selected to receive stimulus funding from the Department of Energy through the smart grid investment grant program. It is receiving about \$130 million, and providing data back to DOE on the results thus far, including saving money on meter-reading costs and discovering customers that tampered with previous meters when the advanced meters are installed, Longcrier said.

Similar to a few other utilities installing advanced meters and discovering customers trying to manipulate meters to show lower electricity usage, “we’re finding fraud that we wouldn’t have known about” without changing the meters, she said, noting that 315,000 advanced meters have been installed. While the number of meters that have been tampered with is limited, “it’s scary because of the safety concern” and danger tied to tapping into live power lines, Longcrier said.

In the home, the advanced meters, thermostats, in-home displays and communication technologies allow consumers to respond to price signals, and OG&E and others are showing that consumers will indeed respond, Energate and Silver Spring said in its summary of the program. “There is skepticism on how many consumers will change their behavior to save a few dol-

lars,” but OG&E and other utilities Energate is working with are exceeding expectations, Niraj Bhargava, CEO and co-founder of Energate, said in an interview.

For Energate, which was formed in 2004, building a business in the growing smart grid segment is like being “in a crowded, noisy train station,” said Bhargava, who was at GE prior to launching the firm. To carve out its specialty, Energate is focused on residential demand response plans, because home energy management is becoming more important and many of the business cases for smart grid technologies are driven by residential customers responding to market signals, he said.

“We try to understand a utility’s goals and then configure a demand response solution to match them,” Bhargava said. It is involved in about 20 different utility projects to date, many of which were not prompted by smart grid stimulus funding. “We didn’t want to build a business based on a requirement for government funding,” he said.

— Tom Tiernan

FERC urged to alter NOPR ... from page 1

ship between e-Tags and transactions,” the associations said. For example, a single e-Tag can represent multiple parties. Also, some transactions do not have e-Tags because they do not cross balancing authority areas. Therefore, matching of transactions and tags would have to be done manually. “The complexity of this matching exercise should not be underestimated.” Entergy also commented that e-Tag data should not be required.

The associations filed individual comments regarding the rest of the FERC proposal.

The commission plans to revise its regulations to require certain of the larger municipal utilities, cooperatives and federal power authorities, sometimes referred to as non-jurisdictional utilities, to begin filing EQRs (Docket No. RM10-12).

It also would make all filers provide more details in the EQRs, such as transaction dates, times and types of rates. In addition, filers would have to tell FERC whether the transaction was reported to an index publisher and, if they were, name the publisher. Reports also would identify any broker or exchange platform used for sales transactions and provide e-Tag data.

Non-jurisdictional entities would file quarterly reports on their electricity deals if they have more than 4 million MWh in annual wholesale power sales. The proposed rule would apply to non-jurisdictional balancing authorities with more than 1 million MWh in annual wholesale deals, FERC said. Utilities located entirely in Alaska or Hawaii would be excluded from the requirements.

While reiterating its opposition to FERC extending the reporting requirements to non-jurisdictional utilities, NRECA nevertheless suggested changing the way the commission would calculate whether entities meet the *de minimis* threshold. It should be based on wholesale sales but exclude from that measurement any non-jurisdictional utility’s sales to its members, NRECA said. Also, the commission should not require billing

adjustments to be reported when it involves deals between utilities and their members.

Moreover, the 4 million MWh threshold should apply to all entities, NRECA suggested. EEI suggested just the opposite — that FERC adopt a 1 million MWh threshold for all market participants.

LPPC does not oppose the proposal to make non-jurisdictional entities file EQRs, it said. However, “these measures must be targeted to the collection of information that is demonstrably useful in the commission’s work, and the burden of producing the information must be balanced against its usefulness.”

BPA listed several types of transactions that it should not have to report, including “statutorily mandated cost-based power sales to consumer-owned utilities.” Regarding these transactions, “Bonneville’s rate design does not mesh with the EQR format since there is not a per MWh charge for the power provided to COUs.” Other deals BPA wants left out are cost-based transmission sales, “resales to self” used by customers to consolidate reservations, and power sales to direct service industries.

Some comments suggested that regional transmission organizations and independent system operators should be required to report or publish data for transactions made in their markets. Having RTOs/ISOs report the data would leave “their individual members responsible only for reporting bilateral and other off-market transactions,” EEI said.

APPA reiterated its argument for making RTOs/ISOs publish

bid information within a reasonable time frame rather than having RTO/ISO members report to FERC. It also reemphasized its belief that power agencies and districts should not have to report to FERC wholesale sales to their members or long-term distribution customers. “Reporting these sales in EQRs serves no useful purpose that would justify the burden of collecting this data, as such sales play no role in price formation in the wholesale markets.”

FERC’s basis for expanding the EQR reporting requirements to non-jurisdictional utilities was challenged by APPA. The commission said deals by non-jurisdictional entities make up a major portion of markets and that FERC would be missing the big picture without seeing those deals. “FERC’s calculations are incorrect and overstate the percentage” of non-jurisdictional utilities’ sales, APPA said.

The commission should give entities adequate lead time to “come up to speed in managing the new compliance requirements,” LPPC said. It suggests a six-month deadline. BPA asked that the compliance deadline be at least a year out from the rule’s issuance, starting in the first full quarter after the one year mark.

FERC also is seeking access to e-Tag data through another proposed rulemaking that would have the North American Electric Reliability Corp. provide commission staff with comprehensive electricity transmission scheduling data (Docket No. RM11-12).

— *Esther Whieldon*

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