DOE IG criticizes FERC handling of sensitive electric grid vulnerability analysis

DOE’s Inspector General issued a highly critical report last week faulting FERC’s handling of information about potential vulnerabilities of the electric grid.

“Our review revealed that the commission’s controls, processes and procedures for protecting nonpublic information were severely lacking,” DOE IG Gregory Friedman said. “Specifically, we found that staff inconsistently handled and shared commission-created analyses that identified vulnerability of the nation’s electric grid without ensuring that the data was adequately evaluated for sensitivity and classification.”

The report focuses on how former Chairman Jon Wellinghoff and FERC staff handled an analysis of the vulnerabilities of the electric grid, which was shared in meetings with industry and officials in Congress and other agencies at several points in 2013. In February 2014, The Wall Street Journal cited the FERC analysis in reporting that a coordinated attack on just nine of the 55,000 electric transmission substations in the US would cripple the grid and produce a nationwide blackout.

The IG found that FERC officials failed to have the analysis in question reviewed to determine if it should be classified, despite concerns that the information was a matter of national security. The report also said FERC staff was “not prepared to deal with internally created documents”.

FERC seeks 5.1% increase in operating expenses for FY-16 due in part to rent hike

FERC last week requested $319.8 million for FY-16, a $15.4 million (5.1%) increase from the FY-15 enacted appropriation to account for its rent going up and a slight salary bump for staff.

While costs to run the agency are expected to rise in FY-16, the commission ultimately anticipates spending 2.3% less compared with FY-15 due to a dramatic drop in building modernization expenses — which are not part of the commission’s regular operating costs, FERC pointed out in its request.

With the lease on FERC’s Washington, DC, headquarters building expiring in September, Congress approved a 10-year renewal option. Lawmakers, however, stipulated that the commission consolidate its workforce to its headquarters building to achieve a 12% reduction in office space utilization.

As a result, a $58 million building modernization project was conceived in FY-14 to relocate employees back to FERC headquarters, renovate the building and make better use of the space with modernized floor configurations.

FERC plans to spend $19.7 million in FY-15 on the initial design and construction costs associated with the building modernization project. Major construction work is scheduled to begin in FY-16 with a project completion date targeted for FY-20.

The project will be paid for in FY-15.

Powhatan, Chen push back against manipulation charges

Powhatan Energy Fund and others last week blasted allegations that they engaged in market manipulation, defending the trades at the heart of the matter and offering a sharp critique of the investigation.

Powhatan in particular called the allegations levied by FERC’s Office of Enforcement “a pile of nonsense,” saying that enforcement staff “has done a disservice to the commission by throwing this nonsense in the commission’s lap and basically saying — here, you deal with it.”

Powhatan made these comments in its official response to FERC’s order to show cause (IN15-3), which required Powhatan, Houlian “Alan” Chen and two firms founded by Chen (CU Fund and HEEP Fund) to respond to allegations that they manipulated PJM Interconnection in 2010.

FERC staff alleges that the respondents inflated trading volumes of up-to-congestion (UTC) transactions to “wrongfully collect large amounts” of marginal loss surplus allocation (MLSA) payments, under which entities trading power
receive surplus payments from transmission line loss charges.

Powhatan faces a penalty of $16.8 million and $3.465 million in disgorged profits under the order, with CU Fund and HEEP Fund facing combined penalties of $12 million and combined disgorged profits of roughly $1.25 million. Chen himself faces penalties of $1 million for trades executed in connection with the matter.

The case has drawn significant attention in part because Powhatan has chosen to vigorously defend itself outside of the FERC enforcement process, releasing formerly non-public documents and enlisting outside experts to defend their positions. Should FERC agree with staff’s allegations, the respondents have chosen to have a federal district court review their case de novo, or from the beginning (IN15-3).

Attorneys for Powhatan and Chen in separate filings February 2 challenged FERC staff’s view that the trades at the heart of the allegations are fraudulent. FERC staff alleged that Chen engaged in matched-pair trades that left him “with no net position in the market, but created the illusion of bona fide market activity.” Staff as well described the trades as “wash-like” and compared the trades to those that FERC has condemned in the past.

Both Powhatan and Chen opposed those arguments, with Chen’s reply arguing that the trades in question “made or lost money on a stand-alone basis” and are distinct from “economically meaningless” wash trades. “Like pregnancy, wash trading is a binary state. There is no in-between,” Chen said.

Chen and Powhatan as well argued that FERC had opportunities to state that the trading in question was unlawful and did not do so, pointing to proceedings where FERC recognized the MLSA credits would provide incentives to virtual traders and yet still allowed them to be included in the allocation of those credits.

“As despite having had the opportunity to circumscribe the very conduct at issue in this matter, the commission did not ask PJM to limit or qualify the virtual traders’ receipt of rebates for UTC transactions, nor did the commission issue any pronounce-

ment or order advising virtual traders that it would consider trading for the rebates to be wrongful conduct,” Powhatan said.

As such, Powhatan argued that it had no fair notice that the trading in question was unlawful, contending that the case is unconstitutional under its protections of due process.

“Given that the commission had specifically acknowledged such incentives and declined to prohibit or discourage trading influenced by such incentives, Powhatan had every reason to believe that the trading was lawful. The paramount concern of due process is ‘that individuals have fair notice of the standards under which they may be held liable,’” Powhatan said, quoting a federal court ruling in a Securities and Exchange Commission enforcement case.

Similarly, Chen’s reply said that “the fair notice doctrine poses an insurmountable hurdle for enforcement’s case because legislators and regulators are required to give fair warning of ‘what the law intends to do if a certain line is passed.’ And that never happened here.”

Respondents as well challenged staff’s view that they exploited a market loophole and thus engaged in market manipulation, with Powhatan saying that “traders who aggressively exploit loopholes do both the market and the rule makers a service by highlighting the inefficiency of the rules, thereby leading the rule makers to fix whatever problem may exist.”

Said Powhatan, “the bottom line is that the staff, as well as PJM, simply does not like the trading at issue because it was too bold, too opportunistic, too profitable and, most importantly, too embarrassing because it exposed the loophole in the system.”

Elsewhere in its answer, Chen argued that FERC cannot show that his actions meet the standard for market manipulation, that FERC doesn’t have jurisdiction over the trades in question and that the proposed penalties are unreasonable. He also requested oral argument on the matter, saying that it will help “provide guidance not only as to what is unlawful but what is lawful and where the line between the two is drawn.”

Powhatan as well rejected enforcement staff’s arguments link-
Groups argue evidence not there to support changing gas day's start time

Data from grid operators has failed to provide evidence to justify changing the start time of the natural gas operating day, or show that such a change would improve reliability at gas-fired power plants, gas trade groups said in comments filed to FERC last week.

FERC in December asked regional transmission organizations and independent system operators how often generators had to reduce output or shut down between 3 am (all times central time unless otherwise noted) and 9 am because they had exhausted their daily nomination of gas transportation service before the end of the gas day.

The data request was part of the commission’s proposal to move the start of the gas day from 9 am to 4 am to prevent gas supply problems during the morning electric ramp period (RM14-2). Gas-fired generators have said that a 4 am start time would better match gas shipments with peak power demand.

However, gas groups told FERC that the responses from the six US-based RTOs and ISOs submitted to the commission in January show that regional electricity markets, for the most part, either do not have a hard time securing gas to meet the morning ramp-up in electric demand or do not collect the data necessary to determine the cause of outages, let alone point the finger at the gas day.

“Unsupported assertions that generators would be ‘better positioned’ with an earlier gas day or data that relies on vague outage codes are not sufficient record evidence to satisfy the commission’s Natural Gas Act Section 5 burden necessary to change the current national 9:00 am CT gas day and move to a 4:00 am CT gas day,” the Natural Gas Council said in its comments filed February 2 to FERC.

Rep resenting 10 major gas industry or gas customer associations, NGC pointed out that the number of outages reported in regional markets during the morning ramp were generally proportional to the number of outages during other times of the day.

“Since the reported outages occurred at relatively the same rate during other times of the day in nearly all of the examples cited, ... it is not possible to conclude that there is a correlation, or even imply that there is causation, between the beginning of the gas day and outages during the morning electric ramp,” NGC said. “Moreover, the data does not show that the gas day was a major contributing factor to generator outages, nor does it show that the current gas day start time affected the overall reliability of regional power markets.”

Further, NGC noted that only three grid operators — ISO New England, New York Independent System Operator and PJM Interconnection — contended that the gas day start time contributed to outages during the morning ramp.

California Independent System Operator and Midcontinent Independent System Operator said in their responses that securing fuel to meet the morning ramp was not a problem, while the Southwest Power Pool said it did not collect data on the underlying causes of de-rates.

“Simply on the face of these three submissions by CAISO, MISO and SPP alone, it is evident that no nationwide issue exists that would justify a change to the current gas day,” NGC said. “The case cannot be made that there is a need to impose a national ‘solution’ on the entire natural gas industry to address what are, at best, limited regional power market issues.”

It added that MISO, SPP, PJM and ISO-NE all revealed that their current data collection practices did not include the level of specificity to determine if outages were the result of exhausting their gas supplies.

Grid operators that did cite a “lack of fuel” as causing an outage did not give details on “whether the generators contracted for firm or interruptible transportation, whether they made adequate advance arrangements with marketers or producers to secure delivered gas or whether the regional operator gave unexpected dispatch orders,” NGC said.

So even if an outage was fuel-related, there was no data available to indicate that the start of the gas day was a factor, NGC said.

NGC’s comments were submitted on behalf of the American Forest & Paper Association, American Gas Association, America’s Natural Gas Alliance, American Public Gas Association, Gas Processors Association, Independent Petroleum Association of America, Interstate Natural Gas Association of America, Natural Gas Supply Association, Process Gas Consumers Group and the Texas Pipeline Association.

Separate comments, making similar arguments, were also filed by APGA, the New England Local Distribution Companies and the Coalition for Enhanced Electric and Gas Reliability.

“The more important problem, especially in the New England area, is the over-reliance of gas-fired generators on non-
firm transportation capacity — a problem that will not be cured by any of the measures proposed in the [notice of proposed rule-making].” APGA said.

The group said the grid operators’ responses only further confirm the need for the “electric industry to take important self-help steps to foster greater reliability.” Such steps, it said, could include securing firm transportation capacity, installing adequate dual-fuel capability, investing in gas storage facilities or “making other infrastructure investments to ensure the availability of a firm power supply during peak periods.”

NGC added that FERC’s attention is better “focused on addressing regional power market fuel assurance improvements.” The commission in November said it would take a comprehensive look at how wholesale power markets value the security of generators’ fuel supplies, while at the same time outlining potential steps grid operators could take to address the issue (IF, 24 Nov ’14, 9).

Washington insiders anticipate FERC will decide the gas day matter in a final rule on gas pipeline scheduling by this spring.

Gas-electric coordination gained prominence among regulators as a boom in domestic gas production made the price of gas attractive for many generators, pushing a larger share of the country’s electricity mix toward gas-fired generation. New emissions standards also have played a part in the move to gas.

But the gas market, designed to handle long-term firm transportation commitments, has yet to adapt to the spur-of-the-moment gas needs of power generators, and some question whether it should have to and at whose expense.

The commission’s NOPR also proposed starting the first day-ahead nomination opportunity for pipeline scheduling later, at 1 pm. The order would increase the number of intraday nomination cycles from two to four. The new intraday nominations would be at 8 am, 10:30 am, 4 pm and 7 pm, under the proposal.

Through the North American Energy Standards Board, the gas and electric industries were able to reach a consensus on this portion of the NOPR, suggesting revisions that were submitted to the commission in September. Those revisions matched FERC’s proposal to push back the timely nomination cycle to 1 pm from 11:30 am, but proposed three intraday nomination cycles instead of four with deadlines at 10 am, 2:30 pm and 7 pm. NAESB could not reach a consensus on the start of the gas day so left that issue out of its proposal.

— Jasmin Melvin

**DC Circuit rejects case brought by cogeneration plant on procedural grounds**

The DC Circuit Court of Appeals last week rejected a suit against FERC on the grounds that the cogeneration plant bringing the suit failed to properly seek rehearing on the matter.

Midland Cogeneration Venture Limited Partnership challenged a batch of FERC orders that in part found that Midland was required to pay two entities under contracts that the plant called “unenforceable.” According to the DC Circuit’s order (Midland Cogeneration Venture Limited Partnership v. FERC, 12-1224), the plant argued that the commission “unlawfully allowed late-filed contracts to be enforceable prior to their effective dates” and were billed at rates that were “impermissible.”

But the court in a per curiam order found that Midland failed to seek rehearing on the initial order on the matter, and instead sought to challenge the order by challenging subsequent orders. The court said that it was prevented from addressing all of Midland’s challenges regarding the order it did not seek rehearing upon “as we are generally prohibited from exercising jurisdiction over collateral attacks on prior FERC orders.”

The court also found that it lacked jurisdiction to consider Midland’s challenges to a related order, given that Midland challenged the rates it was being billed and not other issues it brought before the court.

— Bobby McMahon

**New York utilities defend requested transmission rate incentives for projects**

A group of New York utilities last week defended its request to receive transmission incentives for a batch of projects proposed to be built in the Empire State, arguing that the request is consistent with commission precedent and not premature.

The NY Transco partnership is asking FERC for a number of rate incentives as part of their proposal to build five transmission projects which they say will help to improve statewide reliability. Those incentives include recovery of costs if the project is abandoned for reasons beyond the backers’ control, a base return on equity with certain adders and others (ER15-572).

The partnership comprises Central Hudson Gas & Electric, Consolidated Edison, Niagara Mohawk Power, New York State Electric & Gas, Orange & Rockland Utilities and Rochester Gas and Electric. The group has also asked FERC to authorize the transfer of certain transmission facilities into a stand-alone transmission company (EC15-45).

But the proposals have run into opposition from the state’s industrial consumers, which argued in a protest last month that the proposed ROE is excessive and should be rejected. The industrial consumers also argued that it would be premature for FERC to act in the case of the two projects that have yet to receive approval by the New York Public Service Commission.

“There is no compelling reason for the commission to consider now certain proposed transactions involving transmission projects that are in the early stages of development and for which no state regulatory approvals have yet to be procured,” the industrials said.

Separately, the New York Public Service Commission argued that the ROE was excessive, while also saying that the cost estimates for two of the projects in question were higher than they were when under review by the PSC.

But the utilities on February 2 defended their proposal, arguing that the objections “rest on selective readings of the record, misinterpretations of the Federal Power Act and related commis-
Industry set to fight Obama budget’s MLP tax overhaul, if it doesn’t fizzle out on its own

The energy industry is expected to battle the Obama administration’s budget proposal to scrap the tax benefits of the master limited partnership structure, seen as particularly critical for the gas and oil midstream sector, which considers the favorable treatment necessary to boost investment in infrastructure.

“I do think there would be a lot of pushback on this,” said Rob Desai, an equity analyst at Edward Jones. “We have some time to go” in the federal budget process, he said, but “if it makes it pretty far down the line, that is when I think you will see industry come out and really start to fight it.”

At issue is two lines buried on page 128 of the White House FY-16 budget proposal. The provision would treat publicly traded partnerships for fossil fuels as C corporations starting in 2021. The proposal would remove the tax benefit under which MLP unit holders pay income taxes but the MLP itself does not.

This business structure is popular among energy companies like crude oil and natural gas pipelines because it helps them invest in their systems. “If they are not paying taxes, there is less cash going out the door so that allows them to spend more money on infrastructure buildout,” Desai said.

A couple of groups immediately decried the measure and the negative impact it would have on energy infrastructure.

“The president and his administration have spoken out about the need to improve America’s infrastructure; however, altering the MLP tax structure as this budget proposal suggests would accomplish the opposite – reducing infrastructure investment by close to 30% in the near term,” the National Association of Publicly Traded Partnerships said in a February 2 statement.

Meanwhile, the Interstate Natural Gas Association of America said it would oppose any changes to the MLP structure. “Our analysis suggests that the country will need billions of dollars in additional investment in gas transmission pipelines over the next 20 years to keep pace with supply developments and increased demand,” Martin Edwards, INGAA’s vice president, legislative affairs, said in an email.

“We urge Congress to ‘do no harm’ to a solution that has worked so well, and has attracted private dollars to build energy infrastructure that benefits the broad public interest,” Edwards added.

Others echoed the argument that it would be a bad idea to scrap the MLP tax structure. “Congress set out to stimulate investment with MLP tax treatment for resource industries, and it’s worked,” said Rick Smead, managing director for advisory services at RBN Energy. “We still need a couple of hundred billion bucks’ worth of new infrastructure to support energy abundance.”

According to the president’s budget, the measure would decrease the deficit by $303 million in 2021, and save a total of almost $1.7 billion between 2021 and 2025.

But some say that is not a lot of bang for the buck. “Comparing that to some of the other line items, that’s a relatively small number,” Desai said. “If you take that number relative to the drop in investment in infrastructure, the argument would be that it is not worth it.”

NAPTP struck a similar note, arguing that the value of MLPs “only grows more apparent when you compare the disproportionately small projected revenues gained by corporate taxation to the amount of private investment that would be lost.”

This is the first time the president has proposed such a sweeping change to MLPs, and if it were to be included in the final budget, it would have a huge impact on energy companies, observers said.

“This is the biggest risk for MLPs in general,” Desai said. “I think there would be a significant drop in MLPs if this were to pass, but again, I don’t think it would because of the cost-benefit.”

If MLPs lost their tax benefit, there would be other factors that would still make the structure attractive — such as the way distributions are paid and the way capital is focused on specific projects, Smead said. “But adding a major cost would definitely undermine the economics,” he added.

But Smead agreed that the measure would face an uphill battle. “The Republican Congress doesn’t appear to be very wellcoming to the president’s overall proposals,” he said. “In some mega-deal trading this for that, could MLPs fall victim? Sure, but organizations such as NAPTP are working hard to prevent that.”

A 2012 study sponsored by NAPTP found that subjecting MLPs to corporate taxation would lead to a decline in pipeline investment of 28.7% in the near term, with investment still 13.3% to 20% lower ten years after the tax change,” Mary Lyman, Executive Director of NAPTP said in an email statement.

Although it’s disappointing that the president’s budget proposal called for taxing MLPs at the corporate rate, it’s highly unlikely that this provision would become a reality,” Lyman
said. “Many members of Congress are very supportive of the MLP tax structure and recognize its value as it drives the much-needed private investment required for building our nation’s energy infrastructure.”

Indeed, Senator James Inhofe, Republican-Oklahoma, had some choice words about the proposal. “The president proposes repealing the master limited partnership organizational structure, which would dramatically increase the cost of raising capital for Oklahoma’s energy industry and, in turn, would stifle job creation,” he said in a February 2 statement.

And so far it appears that the market isn’t too worried that the MLP budget measure will survive. “If you look at stocks, MLPs have not been hit hard. So that’s the market’s way of saying, ‘yeah, there’s a proposal but the market doesn’t expect it to go through,’” Desai said.

— Kate Winston

Dominion closes deal to take over CGT, with plans to drop into MLP structure

Richmond, Virginia-based energy conglomerate Dominion has closed a deal to buy Carolina Gas Transmission from SCANA for $492.9 million, the company said last week.

CGT resulted from the 2006 merger of SCG Pipeline and South Carolina Pipeline, both SCANA subsidiaries. It delivers about 700 MMcf/d of gas to wholesale and direct industrial customers throughout South Carolina, but three projects already underway — with binding customer agreements — will increase the system’s capacity to around 820 MMcf/d by 2018.

“Dominion expects to build upon CGT’s existing infrastructure growth plans to enable this fully subscribed system to meet the increasing demand for natural gas transportation services in the region,” Dominion said in a statement February 2.

The acquisition of the 1,500-mile interstate pipeline system in South Carolina and Georgia further expands Dominion’s natural gas holdings.

The company already operates nearly 11,000 miles of gas transmission, gathering and storage pipeline and serves 1.3 million natural gas customers through its subsidiaries Dominion Hope in West Virginia and Dominion East Ohio in Ohio.

It is also the lead developer of the proposed 550-mile, 1.5 Bcf/d Atlantic Coast Pipeline, which is being designed to move gas out of the Marcellus and Utica shales south to utilities and power generators in the Southeast US. The pipeline, estimated to cost between $4.5 billion to $5 billion, would run southeast from Harrison County, West Virginia, across central Virginia then southwest through North Carolina, ending just south of Fayetteville.

Dominion said it intends to add CGT to its master limited partnership, Dominion Midstream Partners, and expects the contribution “to be immediately accretive to [the MLP’s] distributed cash flow per unit.” It added that “this transaction supports the partnership’s intention to grow distributions to unitholders at a best-in-class rate.”

An MLP is a publicly traded partnership that combines the tax benefits of a limited partnership — which only pays taxes when unitholders receive distributions — with the liquidity of a publicly traded company.

Dominion Midstream was formed last March and began trading on the New York Stock Exchange in October. Its initial asset consists of preferred stock in Dominion Cove Point LNG, which owns and operates a liquefied natural gas terminal in Calvert County, Maryland.

Dominion is expected to drop even more midstream assets down into the MLP in years to come, including the Blue Racer and Atlantic Coast pipelines, $5 billion worth of pipeline projects designed to move gas from the Utica (Blue Racer) and Marcellus (Atlantic Coast) shales to markets in the Southeast US.

CGT would be dropped into the MLP for a combination of debt and units by mid-year 2015, if the move can secure board approval from both Dominion and Dominion Midstream.

As part of the acquisition agreement, Dominion has committed to keeping CGT’s 120-person workforce onboard and keeping rates stable for CGT customers for an “extended period,” the company said.

— Jasmin Melvin

LIQUEFIED NATURAL GAS

Parallax unveils plans for major Louisiana LNG export project

Houston-based Parallax Energy is planning to build a major liquefied natural gas export project in Louisiana on the west bank of the Calcasieu River.

Capable of moving up to 5 million mt/year (233.5 Bcf/yr or 6.61 Bcm/yr of gas), the Live Oak LNG project would include two 130,000-cubic meter (2.75 Bcf or 79.17 million cu m of gas) LNG storage tanks and port facilities with a jetty for standard-sized LNG carriers, the company announced last week.

Initial study work has already started and Live Oak intends to begin the permitting process in the next few weeks, the statement said. The anticipated start-up of the plant would be in late 2019.

The Live Oak project is a fully owned subsidiary of Parallax Energy, a new company led by Martin Houston, former COO and executive director of BG Group.

“[W]e are well positioned as a company to succeed with this project,” said Houston. “Our team has over 100 years of LNG experience, our project is well researched, we are fully funded through to final investment decision, and we are supported by world-class experts and suppliers,” Houston said.

Live Oak has awarded Bechtel a contract for pre-engineering design, and Chart Industries has been selected to do the process design work, according to the statement.

— Michael Rieke
Awaiting EA, Wyden raises fire protection concerns over Jordan Cove LNG project

With the release of a final environmental analysis of a liquefied natural gas export terminal proposed to be built in Oregon expected by the end of this month, Senator Ron Wyden wants more information on how the environmental and public safety risks of LNG projects are gauged.

The Oregon Democrat said in letters sent to FERC and the Department of Transportation’s Pipeline and Hazardous Materials Safety Administration that public comments filed regarding the LNG terminal Jordan Cove Energy Project wants to build in Coos Bay have questioned “the adequacy of the hazard modeling used to measure vapor cloud dispersion.”

FERC, working with PHMSA, provides guidelines on fire protection regulations for LNG facilities, which aim to keep fire and explosion hazards contained to a terminal’s boundaries and away from the public.

The commission’s review of terminals includes hazard analyses that model vapor dispersion scenarios and vapor cloud explosions that could occur from LNG spills and the flammable refrigerants used during the liquefaction process.

Wyden asked Chairman Cheryl LaFleur, in a letter dated January 30, to describe the protocol to evaluate environmental impacts and safety concerns related to vapor cloud dispersion. He asked that her response include the models used in the analysis, whether those models are the latest versions available, how much of the assumptions and data retrieved from the models are made public, if there are any constraints on public access to the models and their data and the rationale behind imposing such constraints.

“It is imperative that FERC and PHMSA use the best information and methods available to approve or deny projects, such as LNG facilities,” he said in the letter. “It is also important for the public to have access to as much of this information as possible to ensure transparency in the permitting and evaluation process.”

A similar letter was sent to PHMSA Acting Administrator Timothy Butters.

**FERC previously granted authorization** for Jordan Cove to build an LNG import facility, but that permit was vacated in April 2012 after the company made clear that it — like so many other prospective project sponsors — had shifted its efforts to exporting LNG to take advantage of surging US shale gas production.

The company filed an application (CP13-483) in May 2013 to build export facilities, including four liquefaction trains, two 160,000 cubic meter full-containment storage tanks and a new marine slip with two berths. The export terminal, estimated to cost $5.3 billion, would be capable of sending the LNG equivalent of 160,000 cubic meter full-containment storage tanks and a new

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The Sierra Club, Gulf Restoration Network, and RESTORE originally sought rehearing on the commission’s June 19 order (CP13-25) approving the Cameron LNG project on the grounds that the commission’s environmental analysis was lacking (IF, 28 July, 17).

FERC, in a July 29 notice, rejected that request “as untimely” (IF, 4 Aug, 12). Requests for rehearing were due to the commission before 5 pm July 21, but the environmental groups’ petition was e-filed at 5:00:25 pm and was considered by the commission as filed on July 22 because it was received after the close of business.

The groups then sought rehearing of that decision in an August 7 filing to the commission, arguing that FERC should consider the rehearing request on the merits because the filing time on their original request should have been rounded to the nearest minute and, either way, was a de minimus violation that did not prejudice any party. FERC on September 26 also denied

Court to review Sierra Club challenge of Cameron LNG project, gear up for Freeport

A federal appeals court will hear arguments challenging a FERC order authorizing Cameron LNG’s plan to export liquefied natural gas from Louisiana and the subsequent rejection of a petition for rehearing on that order for being filed 25 seconds late.

The DC Circuit Court of Appeals said last week that the merits of the case were not so cut and dried as to warrant a summary judgment, and that FERC’s motion to dismiss required further review before a three-judge panel.

The Cameron LNG project includes a three-train liquefaction facility that would export the LNG equivalent of 1.7 Bcf/d of gas from Cameron Parish, Louisiana, and a 21-mile, 42-inch-diameter pipeline to feed gas to the facility.

The Sierra Club and Gulf Restoration Network filed a petition for review with the DC Circuit on September 29 after their attempts to persuade the commission to reconsider its approval of the LNG project were scuttled by a filing mistake, rather than the merits of their position (Sierra Club and Gulf Restoration Network v. FERC, 14-1190).

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that request for rehearing.

In a filing to the court, the Sierra Club and Gulf Restoration Network laid out a statement of issues revealing that they plan to argue against the commission’s procedural rejection of their rehearing petition as well as the commission’s substantive approval of the Cameron LNG project.

They contend that FERC should have considered increased domestic gas production triggered by a rise in gas exports. Further, they believe that the commission violated the National Environmental Policy Act by failing to look at indirect and cumulative effects, including greenhouse gas emissions, of shifting electricity generation from gas to coal when resources are depleted; improperly limiting the scope of its analysis of design alternatives; and doing a poor job ensuring protection for wetlands.

In a motion to the court, FERC said the merits of its decision “to reject Sierra Club’s untimely rehearing petition are so clear that that determination should be summarily affirmed.” It added that “since Sierra Club did not timely seek rehearing of the commission’s approval of the applications, its challenges to that approval should be dismissed for lack of jurisdiction.”

The DC Circuit, however, denied the motion for summary affirmance in an order filed February 4, and set a briefing schedule to review the matter substantively. The court directed the parties to address FERC’s motion to dismiss in their briefs.

Briefs from the environmental groups, FERC and Cameron are due March 23, May 22 and June 22, respectively. Final briefs are due August 7, and the court intends to later set a date for oral argument.

The Sierra Club will have its hands full as it will also appear before the DC Circuit to challenge the commission’s July 30 order (CP12-509; CP12-29) authorizing the construction and operation of the LNG export facility Freeport plans to build in Quintana Island, Texas.

The project includes three liquefaction trains capable of exporting the LNG equivalent of 1.8 Bcf/d of gas, along with modifications to an existing vessel berthing dock, transfer infrastructure and access roads.

The Sierra Club and Galveston Baykeeper, in a rehearing request that was denied by the commission in November, said that further environmental analysis was necessary to bring FERC’s review of the project in line with NEPA.

Among the complaints in the rejected rehearing request were that FERC should have considered increased domestic gas production as an indirect effect of the export terminal and reviewed the cumulative impacts of existing and proposed LNG projects, and that FERC “mischaracterizes and inappropriately relies” on DOE’s conditional authorization of exports from the project.

The Sierra Club and Galveston Baykeeper filed a petition for review of the Freeport project with the appeals court on December 10 (Sierra Club and Galveston Baykeeper v. FERC, 14-1275).

The environmental groups, FERC and Freeport jointly proposed a briefing schedule to the court on January 30 that would require the Sierra Club to file its brief by March 13. FERC would have until May 5 to file, while Freeport’s deadline would be May 20. Final briefs, under the proposed schedule, would be due July 3.

— Jasmin Melvin

Drilling key signal for Europe on US LNG export picture, says Czech energy ambassador

Continued natural gas drilling is the only signal a Czech energy ambassador said he was looking for from the US to bolster his confidence that the country would become a global LNG supplier capable of improving the gas supply picture for markets in Europe.

“If it’s possible to get the gas out of the ground economically, ... it will also probably be interesting for someone to sell it abroad,” Václav Bartuška, the Czech Republic’s ambassador-at-large for energy security, said February 4. “[The natural gas industry] will find a way to influence Congress or to get the permits.”

Speaking at a seminar sponsored by LNG Allies, a group of predominately Eastern European countries backing US LNG exports, Bartuška said that the opinions of politicians can turn on a dime so, for him, the only factor worth considering is “the reality on the ground — how much time it takes to drill, how much money you need for that.”

Russia’s aggressive actions toward Ukraine brought a sense of urgency to the need to expand Europe’s portfolio of reliable energy suppliers. But future energy projections, forecasting a decline in Europe’s gas output, would have required such a search for potential suppliers regardless in the years to come.

“When we look at the possible suppliers in 20 years’ time, the picture is not as clear as it is today,” Bartuška said. For this reason, the Czech Republic is eyeing ways to bring more democracies into the global gas and LNG markets to “create a more stable situation,” prompting Bartuška’s meetings with US officials and visits to US gas and oil plays.

“Democracies usually don’t tell you, ‘I’ll sell you the gas if you follow my line or if you do this for me,’” Bartuška said. He later quipped that Energy Secretary Ernest “Moniz usually doesn’t say things like ‘unless you buy our gas, you will not fly home.’”

When asked what the US could do to attract more commercial agreements for LNG exports and secure a foothold in the European gas market, Bartuška replied that Norway overtook Russia as the biggest supplier of gas to the European Union “simply by being Norway, by not bullying anyone, by not threatening anyone, and that was enough.”

He continued, “When you make a deal with Nigeria, you have to take into account that maybe the president will die one day and God knows what happens then. We have seen Libya ... and it’s all hunky-dory until things went terribly wrong. You can say similar things about other supplies of natural gas which are not exactly stable countries.”

“Get it out of the ground, and they will come,” he said of the US’ prospects for lining up LNG sales contracts in Europe.
However, if the US ultimately opts to side with the train of thought that increased trade of LNG would threaten US energy supplies and cause domestic gas prices to rise, Bartuška said European countries would find another source of gas.

“Look, if you don't want to sell, don't sell. That's my line to your officials,” Bartuška said. “I think it's more beneficial for your country to export oil and gas, but if you think it's better for you to keep it for yourself, we'll find our way. We've done it before.”

Bartuška noted that he believed the US administration — when it came to considering LNG export projects and export permits — was doing what any other country’s administration would do.

“Democracy can be very slow at times, but I have no objection to what [the departments of Energy and Commerce] are doing,” he said.

In the meantime, the EU is taking “significant steps” to prepare for US LNG exports potentially hitting the market, Bartuška said. Long-term contracts for the sale of LNG from US companies directly into European markets and to traders that could end up sending the gas to Europe have already been signed.

Croatian Ambassador Joško Paro added that the EU has been “very active” in planning for the start of US LNG exports, considering infrastructure needs and working to create an integrated energy market.

EU leaders appeared to be “upbeat” regarding Europe’s intentions in this regard, but a major “discrepancy” was still causing some hesitancy, he said.

“We are all encouraged by the Department of Energy, the State Department, the White House to put our money into gas transportation and regasification facilities — this is all very, very expensive — but at the same time they do not tell you we are going to sell you gas because that would increase the prices in America,” Paro said.

— Jasmin Melvin

**ENERGY PROJECTS**

**Tennessee files with FERC to expand pipeline capacity to Southeast markets**

Tennessee Gas Pipeline has filed with FERC to provide up to 200,000 Dt/d of additional natural gas capacity to markets in the US Southeast.

Tennessee, a subsidiary of Kinder Morgan Energy Partners, said in its January 30 application (CP15-77) that the project would “serve the growing demand for firm transportation service to markets in the southeastern United States” while also improving efficiency and reducing emissions on its existing pipeline system.

The Broad Run Expansion project, estimated to cost $406.4 million, would involve building four new compressor stations totaling just over 107,000 horsepower — two in West Virginia, one in Kentucky and one in Tennessee — and making modifications to two existing stations in Kentucky to replace older, less-efficient equipment.

Compressor units at the Kentucky facilities totaling 29,750 horsepower would be abandoned and replaced with “newer, more-efficient, cleaner-burning, and lower-emission compressor units” totaling 52,500 horsepower, Tennessee said in its application.

The project is fully subscribed to Marcellus and Utica shale producer Antero Resources, which has requested that the new firm transportation service come online by November 1, 2017. To meet that targeted in-service date, Tennessee asked FERC to approve the project by January 31, 2016.

This would allow the company to begin clearing trees and vegetation from the new compressor station properties by February 1, 2016, and start all other construction by March 1, 2016, Tennessee said. It added that the proposed timeline would accommodate narrow construction windows brought on by weather, environmental constraints on tree clearing and the need to maintain service for existing shippers.

The project, which would move gas from West Virginia and Kentucky southward, is one in a swath of pipeline backhauls and reversals aimed at capturing growing demand in the Southeast and Midwest.

— Jasmin Melvin

**New Hampshire seeks more time to consider re-routed pipeline expansion into Northeast**

New Hampshire lawmakers at the state and federal levels want more time to consider a major pipeline project that was re-routed and now impacts their constituents.

In letters made public February 3, lawmakers asked FERC to ensure that New Hampshire municipalities and residents were granted a full opportunity to comment on Tennessee Gas Pipeline’s Northeast Energy Direct project, which intends to meet increased natural gas demand in the northeast US through upgrades to its existing system.

The project, proposed in July, would provide up to 2.2 Bcf/d of additional gas capacity to New England states by placing new pipeline as part of separate “supply path” and “market path” components of the project. The project would also involve the construction of eight new compressor stations, modifications at an existing compressor station and miles of market delivery laterals and pipeline looping segments located in Pennsylvania, New York, Massachusetts, Connecticut and New Hampshire.

Tennessee, a subsidiary of Kinder Morgan, in December told FERC that it planned to use two alternative routes for the market path of the project — from Wright, New York, to Dracut, Massachusetts — to minimize environmental impacts and ultimately allow 90% of the project’s route to be adjacent to or co-located with existing rights-of-way.

“The new proposal shifts much of the pipeline out of northern Massachusetts — where it was originally planned
— to southern New Hampshire,” said a January 14 letter to FERC signed by Senators Jeanne Shaheen and Kelly Ayotte and Representatives Ann McLane Kuster and Frank Guinta.

Shaheen and Kuster are Democrats, while Ayotte and Guinta represent the GOP.

“The citizens and municipalities along the initial proposed route benefited from several months to receive and review information, to analyze and deliberate, and to ask questions and express concerns,” they said in the letter. “We strongly believe the citizens and municipalities in New Hampshire, many of whom have just learned that they may be directly impacted by this pipeline project, deserve an equal opportunity.”

The commission on October 2 accepted Tennessee’s request (PF14-22) to begin FERC’s National Environmental Policy Act prefiling process, which allows for early input from stakeholders regarding the possible environmental, landowner and other impacts associated with the siting, design and permitting of a project under FERC jurisdiction.

The New Hampshire delegation asked FERC for information on the prefiling process’ timeline and urged the commission “to extend that timeline to ensure that New Hampshire’s residents have a full and equal opportunity to understand, assess, and comment on this project before any decisions are made finalizing the project or its route.”

In a separate letter sent to the commission January 21, members of New Hampshire’s House of Representatives said that the re-routing “should have resulted in a new schedule for the application process, but apparently this did not occur.”

“The result is diminished opportunity for public comment,” the legislators said, requesting that the comment period on the planned pipeline be extended by at least 90 days.

That letter was signed by John Balcom, Richard Barry, Chris Christensen, Richard Hinch, Josh Moore, Jeanine Notter, Anthony Pellegrino and Phillip Straight — all Republicans representing Merrimack, New Hampshire.

The revised route would encompass 188 miles of new and co-located mainline pipeline facilities, of which about 71 miles of pipe would be co-located with an existing power utility corridor in southern New Hampshire.

Kinder Morgan has said that the new route would benefit New Hampshire by expanding gas service into new areas of the state through agreements with Liberty Utilities and others.

The NED project has capacity scalable from 800,000 Dt/d to 1.2 Bcf/d, or ultimately up to 2.2 Bcf/d, depending on final customer commitments.

Tennessee said it expects to submit an application for the project in September and will ask FERC to approve it by October 31, 2016. It anticipates construction to begin in April 2017 to meet an in-service date of November 1, 2018 for all of the project facilities except two proposed pipeline looping segments in Connecticut. Construction of those two loops would begin in April 2019 and be put in service by November 1, 2019, the petition to begin the prefiling process said.

Low energy prices could encourage infrastructure investment, House panel told

Congress should help speed permitting for energy infrastructure projects so that industry can take advantage of the lull in commodity prices to build enough pipelines to keep up with production, experts told members of the House last week.

“Now is the opportunity for investment in midstream infrastructure to catch up to the past resource development that occurred,” Jason Thomas, managing director of The Carlyle Group, told the House Transportation and Infrastructure subcommittee on railroads, pipelines and hazardous materials.

Subcommittee Chairman Jeff Denham, Republican-California, said he wanted to hear what industry is doing to boost the capacity of the rail and pipeline networks to ship energy. “We also want to understand how government can be supportive of their efforts, and if there are roadblocks, what we can do to remove them,” Denham said at the hearing.

Low oil prices mean that investors are shifting their attention away from energy production and toward transportation infrastructure, which is not as sensitive to commodity prices, and energy-intensive industries that benefit from low energy prices, Thomas said.

Returns on midstream infrastructure investments, such as pipelines, rail and barges, gas storage and gathering systems, can be “invariant” to energy prices, Thomas explained in his written testimony. “For example, the monthly returns on midstream master limited partnerships have exhibited a lower correlation with changes in the price of oil than the overall S&P 500,” Thomas added.

Congress could speed investment in infrastructure by streamlining the permitting process, Thomas said. For example, lawmakers could ensure that project reviews are concurrent instead of sequential, he explained.

It can take 558 days for a natural gas pipeline to be approved, a timeframe that could reduce a project’s internal rate of return by 36%, Thomas elaborated. “Such delays can make otherwise attractive projects uneconomic.”

The House last month passed a bill (H.R. 161) that would expedite the gas pipeline permitting process by requiring the FERC to approve or deny a gas pipeline certificate within one year of receipt of a complete application.

Other state and federal agencies would be required to approve or deny related authorizations, such as Clean Water Act permits, within 90 days of FERC issuing an environmental review of a project, with the possibility for a 30-day deadline extension.

However, the White House called the bill’s timeframes unworkable and threatened to veto the legislation.

While that bill applied to gas pipelines, Andy Black, the president of the Association of Oil Pipe Lines, said liquids pipeline approvals also need to be expedited. “We need decision making, whether it is federal or state, to be more timely so that pipeline operators can respond and not have these unnecessary delays,” he told the subcommittee.

While oil pipeline siting is overseen by states, FERC regulates

— Jasmin Melvin
the rates and conditions of service for crude oil and petroleum product pipelines.

“To improve federal infrastructure permitting, AOPL encourages additional resources for federal permit review, commonsense decision-making, and more regulatory certainty,” Black said in written testimony.

Meanwhile, Edward Hamburger, president of the Association of American Railroads, argued that railroads are the only mode that can expand capacity quickly enough to keep up with production growth in emerging oil fields. “They offer market participants the flexibility to transport product quickly to different places in response to market needs, and rail facilities can almost always be built or expanded much more quickly than pipelines and refineries,” he said in written testimony.

But Jack Gerard, president of the American Petroleum Institute, said both pipelines and rail are needed. “The past era of energy scarcity required a silo approach to energy policy — each mode considered in isolation and in competition with other modes. In this era of energy abundance, we need more of all.” — Kate Winston

**FERC plans EA for Transco project to feed gas to Sabine Pass LNG terminal**

FERC staff has opted to prepare an environmental assessment, rather than a more-thorough environmental impact statement, on Transcontinental Gas Pipe Line’s proposed 1.2 Bcf/d Gulf Trace backhaul project to the Sabine Pass LNG export terminal on Louisiana’s Gulf Coast.

A federal agency, under the National Environmental Policy Act, may decide to prepare an EA, rather than an EIS, when staff experience and judgment indicate that a project is not expected to have the potential to cause significant environmental impacts. The EA will help the commission determine if the project “is in the public convenience and necessity,” the commission said February 4.

Some 263.4 acres of land would be disturbed during construction of the project, which would parallel existing rights-of-way for 17% of the pipeline’s proposed route. More than 70% of the disturbed land would be restored and returned to its former use, with just 75.6 acres being retained for permanent operation of the pipeline and related facilities, FERC said in a February 4 notice.

The commission is seeking comment until March 6 on the scope of issues that should be evaluated in the EA. Staff requested that comments “focus on the potential environmental effects, reasonable alternatives, and measures to avoid or lessen environmental impacts.”

The Gulf Trace Expansion Project would provide firm transportation capacity from Transco’s Station 65 in St. Helena Parish, Louisiana, southward through the existing mainline and Southwest Louisiana Lateral, to a new lateral to the Sabine Pass terminal in Cameron Parish.

The project includes installing a new 7-mile, 36-inch-diameter lateral to the export terminal, building a 32,000 horsepower compressor station in Calcasieu Parish, adding 32,000 horsepower of compression to an existing compressor station in Cameron Parish and modifying piping and valves at existing compressor stations in Beauregard, Evangeline, and East Feliciana Parishes to allow for bi-directional flow.

The project is expected to cost around $278 million, and the additional 1.2 Bcf/d of capacity on the system is fully subscribed to Sabine Pass through a binding precedent agreement, Transco said in its application (CP15-29) submitted to FERC December 15.

FERC has already identified a preliminary list of issues to be considered in the EA, including impacts on wetlands and waterbodies, wildlife, migratory birds, vegetation, threatened or endangered species, land use, air quality, noise and safety.

Cheniere Energy is building four liquefaction trains at the Sabine Pass terminal, with a production capacity totaling the LNG equivalent of 2.76 Bcf/d of gas. The company is awaiting FERC approval to add two additional trains to bring capacity to 4.14 Bcf/d (CP13-552).

Gulf Trace would meet the demand for gas required to feed Trains 3 and 4 at the export terminal, according to Transco’s application. The company asked FERC to approve its pipeline expansion by September 1 to allow it to complete construction and put the project in service by January 1, 2017 — as requested by Cheniere to align with its timeline for bringing Trains 3 and 4 online.

While the first train at Sabine Pass is anticipated to produce LNG as early as late 2015, Cheniere has said it expects Trains 3 and 4 to become operational in late 2016 and 2017, respectively. — Jasmin Melvin

**Spectra asks FERC to start prefiling review of Atlantic Bridge project to serve Northeast**

Spectra Energy subsidiaries have petitioned FERC to begin the early environmental review of the company’s plan to expand capacity on two of its pipelines serving the Northeast.

The Atlantic Bridge Project, proposed by Spectra last February, would allow more gas from the Marcellus and Utica shales to be delivered to key markets in New England and the Canadian Maritime provinces on the existing Algonquin Gas Transmission and Maritimes & Northeast Pipeline systems.

The project would add 222,000 Dt/d of additional capacity between a receipt point on Algonquin’s system in Bergen County, New Jersey, and various delivery points on the Algonquin and Maritimes systems.

“This project is designed to deliver critically needed natural gas supplies that will meet immediate and future supply and load growth requirements in the Northeast market area,” said the January 30 petition (PF15-12) filed by Algonquin and Maritimes.

FERC’s National Environmental Policy Act prefiling process allows for early input from stakeholders regarding the possible environmental, landowner and other impacts associated with the siting, design and permitting for a pipeline and related facilities.

Algonquin and Maritimes asked FERC to approve their petition...
by February 9. FERC’s acceptance of the prefiling request would initiate the first formal stage of federal certification for the project.

The companies said in the petition that they expect to submit an application for the project in September 2015, and will seek FERC approval by November 7, 2016, in order to bring the expansion project online by November 1, 2017.

Six shippers have already signed agreements for firm transportation service from the project, and Algonquin and Maritimes are continuing to negotiate with others, according to the petition.

Spectra has said that the expansion plan has the capacity to funnel more than 600,000 Dth/d of gas to New England, depending on market commitments.

About 23.9 miles of mainline pipeline running through New York and Connecticut and 12.3 miles of lateral pipeline in Rhode Island and Massachusetts would be built as part of the project.

The project would also include building a new 10,915 horsepower compressor station in Massachusetts, modifying two existing compressor stations in Connecticut to add 18,615 horsepower of compression and altering several meter stations on the Algonquin system.

--- Jasmin Melvin

**FERC seeks 5.1% increase in operating expenses for FY-16 due in part to rent hike … from page 1**

with unused funding from FY-14, separate from the $304.4 million appropriated for operating expenses this fiscal year.

The FY-16 budget request includes $2.5 million for the modernization efforts, an 87.1% drop from the prior fiscal year. The funding will cover furniture, IT and security equipment, logistical services and administrative costs for the project.

Regarding its operating costs for FY-16, the commission said its efforts to streamline and make programs more efficient shaved expected administrative costs 11.8% from the FY-15 estimate to $17.8 million, while seeking out information technology initiatives reduced the budget request in that area by 3.1% from FY-15 to $29.8 million.

Still, the new lease for FERC headquarters, which will take effect September 30, increased the commission’s rent by $6.8 million to $30.2 million for FY-16.

The FY-16 request would also support a mandatory 1% pay raise, boosting salaries and benefits by nearly $5 million from FY-15 to $230.8 million.

Additionally, FERC said in its request that it expects program costs to total $8.6 million in FY-16, $1.3 million higher than FY-15, due to the “statutorily required hydropower environmental workload and expert witness contractor assistance in the commission’s enforcement program.”

FERC is revenue neutral and recovers all its operational costs through annual charges and filing fees.

The budget request calls for 1,480 full-time-equivalent employees, the same as FY-15.

The request broke down planned spending by industry as followed: $177.1 million for electric, a 3.1% decrease from FY-15; $74.1 million for hydropower, a 0.3% increase; $60.9 million for natural gas, a 2.9% decrease; and $7.6 million for oil, a 2.7% decrease.

The budget request also includes estimates for the commission’s anticipated workload in FY-15 and FY-16.

It forecast electric rate and tariff filings to fall from 6,018 in FY-14 to 5,000 in FY-15 and the same in FY-16, while oil filings are estimated to dip from 770 in FY-14 to 750 in FY-15 and also 750 in FY-16. Natural gas filings, however, will climb to 1,750 in both FY-15 and FY-16, from 1,503 in FY-14, it estimated.

FERC said in the request that “the increase in the demand for gas-fired electric generation and new or expanded manufacturing is spurring the development of greenfield projects,” and it expects the number of gas pipeline projects to increase in FY-16.

The commission said it approved 44 major pipeline projects in FY-14, amounting to 407 new pipeline miles and more than 398,000 horsepower of compression. It added that it also authorized three storage projects, adding 1.6 Bcf of working gas capacity.

The request noted that FERC completed 19 audits of public utilities and gas pipelines in FY-14 that led to 162 recommendations for corrective actions.

“The major topic areas of the commission’s FY 2015 audits and those anticipated for FY 2016 include: transmission incentives, capacity markets, energy trading, market-based rates, formula rates, mergers and acquisitions, gas tariffs, nuclear decommissioning, and accounting and reporting audits,” the commission said.

FERC pointed out that it issued nine notices of alleged violations in FY-14, launched 17 new probes and brought 15 to close. Investigation and enforcement priorities for FY-15 and FY-16 will focus on “fraud and market manipulation; anticompetitive conduct; serious violations of Reliability Standards; and conduct that threatens the transparency of regulated markets,” FERC said.

Settlements were approved in nine investigations during FY-14, resulting in nearly $25 million in civil penalties and more than $4 million in disgorged profits, FERC said.

The request was part of President Barack Obama’s nearly $4 trillion FY-16 budget plan. That plan would provide $30 billion to DOE, and attempts to make strides to combat climate change while reducing tax breaks for the oil and gas industry. Analysts, however, said that the current political climate, with Republicans in control of both chambers of Congress, makes such measures in the budget proposal “a non-starter” with “little more than symbolic value.”

--- Jasmin Melvin

**DOE IG criticizes FERC handling of sensitive electric grid vulnerability analysis … from page 1**

that may have national security implications,” while noting confusion between FERC and DOE over responsibilities for classifying FERC-created information.

More broadly, the report found a “culture of reluctance to classify certain nonpublic information” within FERC, DOE and
the Department of Homeland Security. The report noted that subject matter experts at the agencies expressed concern that classifying such information would block federal officials from sharing information with industry and working to mitigate threats.

“Thus, in their opinion, the ability to share certain non-public information (like the electric grid analysis) with industry outweighed the benefit of classifying certain nonpublic information,” the IG said. “While we agree that sharing information with public sector utilities is important when attempting to address grid vulnerabilities, we noted that there were mechanisms to permit such exchanges without simply declaring the information to be unclassified.”

The IG’s report recommended that FERC take steps to ensure that employees are prepared to handle classified information and so-called critical energy infrastructure information. In a January 15 letter responding to a draft of the report, Chairman Cheryl LaFleur said the commission has begun implementing the IG’s recommendations.

In a statement last week, LaFleur said the commission was “focused on learning from this experience and improving our processes going forward.”

The report provides detail on the creation of the analysis and acknowledged differing views on the audience for that analysis as well as concerns over its sensitivity.

Unnamed FERC officials interviewed by the IG expressed concern about sharing the information from the analysis outside of FERC, saying that the analysis, “should it fall into the wrong hands, could provide terrorists or other adversaries with data they might use to disable portions of the grid,” the report said.

But Wellinghoff in an interview with the IG disagreed.

“He considered the information to be unclassified because it was drawn from public sources. He also noted that he always intended to provide the information to industry and others so that corrective actions to improve security at substations could be completed,” the report said.

Wellinghoff also told the IG that he “had never been advised by commission officials or [DOE] that the data involved might be classified.”

Calling the inconsistencies between FERC staff and Wellinghoff “troubling,” the report said that the IG’s office sought to review “relevant email traffic” from FERC’s records. While it received “a voluminous amount of email and other supporting documentation for specific periods of interest” from FERC staff, the IG said that “we found no email traffic in the former chairman’s account for the relevant period in October and November of 2013.”

In an interview last year with Platts, Wellinghoff rejected the view that information about the analysis was non-public, while also arguing that it “simply confirmed what we already know” and have known since the early 1980s — that knocking out a small number of substations could disrupt the grid.

Wellinghoff said that there was no more detail in the Journal story than had already been known about the grid’s vulnerabilities, pointing in particular to grid failures that led to the 2003 blackout.

In noting its concerns on the handling of the analysis, the IG’s report said that FERC staff did not “obtain a timely classification decision,” despite several instances where the question of whether the analysis should be classified was raised.

While acknowledging concerns regarding the need to handle the analysis properly, the IG’s report questioned the likelihood of the analysis’ scenario actually occurring. A DOE document quoted by the report called the analysis’ assumptions “highly unlikely” and said that those assumptions would cause “the formation of islands of power within the interconnect for an unspecified length of time, not total loss of power” if they came to pass.

In light of these and other findings on the analysis, the IG said that “these conclusions were apparently important considerations in the decision to find the commission staff’s analysis to be unclassified. Whether intended or not, it appeared as though both commission staff and [DOE] classifiers discredited the very results or consequences of the commission’s grid analysis, effectively rendering it of questionable value.”

In a statement last week, Senate Energy and Natural Resources Committee Chairman Lisa Murkowski called the report’s findings “deeply troubling.”

“Oversight of FERC is an important duty of this committee,” Murkowski said. “As chairman, I will fully review the inspector general’s recommendations, including potential legislative proposals to improve FERC’s handling of sensitive information.”

Wellinghoff did not respond to a request for comment last week.

— Bobby McMahon

MARKETS

ISO-NE touts FERC-approved reforms as capacity auction draws new generation

As expected, ISO New England’s ninth forward capacity auction yielded higher prices than previous auctions, with ISO officials touting how market reforms helped draw new resources to the region.

According to preliminary results released February 4, FCA 9 acquired roughly 34,695 MW of capacity, which included 1,060 MW of new generation and 367 MW of new demand-side resources. The clearing price for Connecticut, Northeast Massachusetts, Greater Boston and other areas arrived at $9.55/kW-month, with prices for imports from New York and New Brunswick receiving $7.97/kW-month and $3.94/kW-month, respectively. The auction covers delivery for 2018-19.

Officials noted, though, that prices were set administratively in southeast Massachusetts and Rhode Island (SEMA/RI) due to insufficient capacity. According to ISO-NE, “the 353 MW of new resources in the zone will receive the auction starting price of $17.73/kW-month, while the 6,888 MW of existing resources in the zone will receive $11.08/kW-month, which is based on the
ISO-NE said that “while the SEMA/RI zone is short about 238 MW of the 7,479 MW needed in 2018-2019, such resource shortfalls may be filled through periodic reconfiguration auctions held over the next three years.”

In FCA 8, which secured capacity for the 2017-18 delivery year, a capacity shortfall caused prices to be set at $15.00/kW-month for new resources and $7.025/kW-month for existing resources for most of the region due to insufficient competition. Prices in the NEMA/Boston area arrived at $15.00/kW-month, an administratively set price.

In a statement, ISO-NE President and CEO Gordon van Welie touted steps the region had taken to reform its capacity market structure. The auction, which concluded February 2, for the first time featured a sloped demand curve and a two-settlement process where entities earn a base capacity payment and then will either pay or be paid based on their resource’s performance, a strategy aimed at incentivizing resource performance.

“These reforms are removing risks from the market and providing investors with the financial stability needed to build new resources in New England, and providing consumers with greater assurance that the region’s power system will have sufficient capacity to keep the lights on, and that those resources will perform when called on,” van Welie said.

In highlighting the results, ISO-NE noted that the region will see almost 3,400 MW of retirements from generation and demand response resources by 2017, which amounts to more than 10% of capacity in the region. While noting that a capacity shortfall drove prices higher in FCA 8, “the price signal from the previous auction attracted a significant quantity of new resources to compete in this auction.”

Those new resources included a 725 MW combined-cycle gas-fired plant in Oxford, Connecticut, and 90 MW of combustion gas turbines located in Wallingford, Connecticut. A 195 MW combustion gas turbine also cleared in Medway, Massachusetts, which is located in the SEMA/RI area.

While ISO-NE officials were unable to confirm, the Oxford plant appears to be Competitive Power Ventures’ proposed Towantic plant. Officials with CPV did not respond to a request for comment by press time.

In a research note before the auction results were released, UBS Securities analyst Julien Dumoulin-Smith predicted that the Towantic plant, if it was bid in, “would likely take advantage of new rules allowing a plant to ‘lock-in’ the initial cleared capacity price it receives for a seven-year period, providing visibility for financing.”

Speaking more broadly about the potential for new generation, UBS said that new gas plants will likely “be focused on the Southwest Connecticut load pocket given the relatively lower degree of gas pipeline constraints (hence better spark spreads). That said, any new resource will be dual-fueled, with [Connecticut] seemingly much easier in terms of getting such a project off the ground.”

Dan Dolan of the New England Power Generators Association said February 4 that the auction went as expected, and if anything prices came in a bit lower than analysts predicted. He also said that, in light of the changes to ISO-NE’s capacity auction in the past year, the auction performed fairly well.

The auction followed FERC action on January 30 declining to rehear its approval of changes to ISO-NE’s capacity market constructs, including the sloped demand curve (ER14-1639) and administrative pricing rules (ER14-463). FERC also denied complaints challenging certain aspects of the capacity market, including one by merchant generators in the region over ISO-NE’s peak energy rent (PER) adjustment mechanism (EL15-25).

The PER adjustment, according to FERC’s order, “is intended to act as a hedge for load against price spikes in the energy market” by requiring generators to return revenue when “real-time clearing prices exceed an administratively-determined strike price.”

NEPGA argued in a complaint that the PER adjustment was rendered unjust and unreasonable because market reforms adopted for FCA 9 created the potential to unfairly increase the amount of revenue returned to load. As part of its request, the group asked that FERC eliminate the PER mechanism starting with the commitment period for FCA 9, saying that the two-step settlement process makes the PER adjustment “unnecessary and improperly duplicative.”

But FERC denied the complaint, finding that NEPGA failed to show that the existing rules were unjust and unreasonable. Commissioners Tony Clark and Philip Moeller in a concurring opinion agreed with their colleagues, but did say that the group raised “valid concerns regarding the continued application of the existing PER Adjustment” in light of market changes.

“We encourage ISO-NE and its stakeholders to continue to consider potential changes to the PER adjustment mechanism,” Clark and Moeller said, adding that FERC will consider complaints if NEPGA is able to provide specific evidence that the existing PER mechanism is yielding unjust and unreasonable results.

FERC late last month also rejected a complaint brought by Exelon and Calpine (EL15-23), which according to the commission challenged certain rules for capacity resources clearing for the first time in the auction. Specifically, ISO-NE rules allow new resources to lock in their clearing price for up to six more periods, with that resource becoming a price-taker for the rest of its locked-in period.

“FCM revenues for the new entrant are guaranteed during the lock-in period regardless of whether capacity clearing prices in subsequent auctions over that period exceed or fall short of the initial FCM clearing price,” FERC noted.

According to FERC’s order, Exelon and Calpine in their complaint argued that “both the price lock-in itself and the zero-price offer requirement unreasonably and artificially suppress capacity prices and result in undue discrimination because new entrants are paid higher prices than are paid to other resources for providing the same capacity services.”

FERC rejected the complaint, finding that Exelon and Calpine “have not demonstrated why it is unjust and unreasonable for a new resource electing the price lock-in to be treated
PJM CEO warns of sharp drop-off should Supreme Court decline demand response case

PJM Interconnection projects that it could lose between 40-50% of its demand response resources should the Supreme Court decline to take up the case of a key FERC rule on demand response, PJM President and CEO Terry Boston said Thursday.

Speaking to a meeting of the National Association of State Energy Officials, Boston said that PJM’s roughly 11,000 MW of demand response is at risk given that the DC Circuit Court of Appeals in May tossed out Order 745, which would require that demand response receive market price in wholesale energy markets (Electric Power Supply Association v. FERC, 11-1486). The court found that FERC infringed on states’ Federal Power Act authority in issuing the rule, given that states have authority over retail matters.

The fate of Order 745 now rests with the Supreme Court, which has yet to respond to calls by the Obama administration, industrial consumers and others to overturn the DC Circuit’s ruling. The high court is expected to decide whether it will take up the case this spring, and in the meantime, the DC Circuit has ordered that Order 745 will effectively remain in place until the Supreme Court acts.

But if the high court does not take up the case, Boston said that PJM has a “pretty immediate problem” on its hands given that it could lose roughly half its demand response resources, which equates to about six nuclear plants, right before the region’s capacity auction in May. Boston added that PJM’s capacity auction has not cleared a single-cycle natural gas-fired unit in the last four auctions because demand response is cheaper as a resource that runs only a small amount of the time.

“We’d have to figure out a way to work with the states to make sure demand side doesn’t fall off the table,” Boston said.

**PJM has proposed a stopgap to FERC** (ER15-852) that lays out how demand response could participate in its capacity auction should the high court not take up the case. PJM proposed to allow wholesale entities to commit to reducing their load, which would reduce the amount of capacity PJM would procure in the auction and thereby reduce the capacity charges load-serving entities are subject to. The proposal would allow PJM to adjust the auction’s demand curve in light of reductions in load.

Speaking with reporters after his comments, Boston said that filing the stopgap with FERC allowed PJM to get a head start on sharing its thinking on the matter. He also noted the uncertainty on the issue should demand response fall to the 13 states and the District of Columbia that encompass PJM.

“One of my fears is that we could end up with 14 different flavors of ice cream that no one likes if it’s on a state-by-state basis,” Boston said.

Noting that there has long been demand-side participation, he said that getting the economics to work for demand response in the retail markets will be harder than it is in the wholesale markets. He said PJM will work with states to ensure that demand response continues to play a significant role.

“We will find a way,” he said. “There will be a period of uncertainty for what the state programs are and how we implement them.”

Boston also highlighted the multiple impacts that low natural gas prices are having on the generation fleet within PJM, including that existing nuclear plants are challenged by low energy market prices.

“Low prices are a good thing, but if they get too low where you don’t maintain your fleet, that’s not a good thing,” Boston said.

Boston also said that the vast majority of new resources in PJM are combined-cycle natural gas plants, predicting that “a record number of new gas plants” will arrive in the May capacity auction. And while acknowledging that gas becoming the dominant fuel is “a little nerve-wracking,” he noted the tendency for particular resource types to dominate specific decades, from hydro in 1940s to nuclear in the 1970s to gas most recently.

“We have a balanced portfolio, but we just got it a decade at a time,” he said.

— Bobby McMahon

LaFleur eyes work ahead to harmonize power markets with carbon reduction goals

Chairman Cheryl LaFleur said Thursday it will take considerable effort to harmonize the operation of regional power markets with the proposed Environmental Protection Agency rule that calls for significant greenhouse gas reductions from the existing power fleet.

“I don’t think this is a problem beyond human imagining to figure out how you rationalize the state implementation plans with the markets, but it is a thing we’re going to have to work on before [the plans] go into effect to make sure we keep the benefits of markets while we get the environmental improvement we’re trying to get through the plans,” LaFleur said.

EPA’s Clean Power Plan seeks to cut carbon dioxide emissions to 30% below 2005 levels by 2030, with interim reduction targets starting in 2020. The proposal would require states to develop implementation plans to meet those targets through strategies including increasing dispatch of natural gas-fired generation and other lower emission resources and boosting the efficiency of existing fossil-fired plants, with EPA stepping in should states choose not to create those plans.

Speaking to a gathering of the National Association of...
State Energy Officials in Washington, LaFleur said there have been times in the past when wholesale power markets have responded to state and national policies, including how markets responded to state-backed renewable portfolio standards. She also said that markets can put particular limits on specific plants based on environmental rules, including when a plant can only run in certain hours.

But the Clean Power Plan presents broader challenges, given that each state will need to come up with its own plan and then those plans will need to be co-optimized, she said. It’s clear that how power is dispatched will need to account for these state plans, she said, with the added challenge that states are looking at the issue on a far broader level than to simply limit the operations of specific plants.

LaFleur said that this “technical, unsexy, dirt-under-the-fingernails work” is what FERC does, expecting that the commission will be involved in working through the market rules behind broader strategies between now and the Clean Power Plan’s target dates.

LaFleur during her comments highlighted the need for new gas and electric infrastructure as part of efforts to help states to comply with the Clean Power Plan, echoing points she has made before several audiences in recent weeks. In response to a question on how states can move toward more regional planning, LaFleur noted that one idea that has started to emerge is the formation of regional transmission organizations for gas similar to the RTOs that operate wholesale electric markets.

“I don’t think we’re going to build those structures in time for this,” LaFleur said of RTOs for gas. “If we’re ever going to build them, I don’t think it’s going to be in time for this. I think we’re going to try to harness and harmonize the existing structures we have.”

LaFleur identified both power RTOs as well as regional transmission and regional reliability entities as among the structures that can work to address planning issues in light of the Clean Power Plan. Rather than creating new entities, she said that stakeholders should use the structures in place to address these issues.

Despite Clark’s dissent, Maxim faces manipulation allegations in New England

FERC last week asked an independent power producer to respond to allegations it engaged in market manipulation in ISO New England, despite concerns by Commissioner Tony Clark that the record in the case does not support moving forward.

In an order to show cause issued February 2 (IN15-4), FERC asked Calgary-based Maxim Power and related entities as well as former analyst Kyle Mitton to answer allegations by commission enforcement staff that the company manipulated ISO-NE in July and August 2010. Maxim faces a proposed fine of $5 million, with Mitton — who according to enforcement staff is now the company’s director of corporate development — facing a proposed fine of $50,000.

Maxim in a statement last week said it “intends to vigorously defend itself before FERC or, if necessary, in federal court and is confident it can demonstrate that the conduct set forth in the order to show cause did not violate FERC’s anti-manipulation rule or any other rule.”

According to the order and staff’s accompanying report, the allegations center on Maxim’s 181 MW Pittsfield plant, which is in Massachusetts and can burn fuel oil and natural gas. According to FERC, the company sought to inflate make-whole payments it received when the plant was dispatched for reliability reasons by basing its fuel costs on more-expensive oil and then burning less-expensive gas.

“During July and August 2010, Maxim regularly submitted day-ahead offers to ISO-NE at high oil prices, but on 22 days when it got reliability commitments, burned much less expensive gas to produce all, or almost all, of the plant’s energy,” the order said, noting that the plant received make-whole payments because it was dispatched for reliability reasons rather than based on economics.

The order also alleged that Maxim in communications with the region’s internal market monitor suggested that the company “was unable to obtain gas and was therefore burning more expensive oil,” even though Mitton had on many days “bought large quantities of gas before submitting a day-ahead offer based on oil prices.”

The documents also noted that the IMM recouped almost $3 million from Maxim for payments linked to these allegations, and as such FERC’s order seeks to levy only penalties.

The order was issued in a 3-1 vote, as Commissioner Norman Bay did not participate and Clark dissented. “I do not find that the record sufficiently supports the commission moving forward” with the order based on staff’s report and responses from Maxim officials, said Clark.

“Nonetheless, in the next phase of the proceeding, both FERC enforcement staff and the respondents will have an opportunity to more fully develop the record. As such, I make no prejudgment as to the final disposition of this case,” he added.

During the investigation, Bay served as FERC’s enforcement chief. Since becoming a commissioner last year, he has consistently recused himself from items that he worked on while in the Office of Enforcement.

In its statement last week, Maxim said it was reviewing the order, while noting both Clark’s dissent and that “the order does not indicate commission adoption or endorsement of the Office of Enforcement’s staff report recommending issuance.” The company also noted it has yet to have an opportunity for discovery or to defend itself before FERC or a federal district court.

Under the Federal Power Act, entities can choose to have enforcement cases heard by either a FERC administrative law judge or a federal district court should FERC agree with enforcement’s findings and levy penalties. Maxim noted that, should it select the district court path, the court will review the case de novo, which means from the beginning.

— Bobby McMahon
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