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FERC NEWS

Ex Parte Rules Raised in Case of FERC Rejecting FirstEnergy Power Plant Sale

While the ruling from FERC in a case rejecting a power plant sale from the marketing arm of FirstEnergy Corp. to a FirstEnergy utility was noteworthy, commissioner statements and discussion of ex parte communications have created more of a buzz in energy legal circles.

FERC Chairman Kevin McIntyre said he is meeting with staff to assess whether FERC staff tipped off an outside attorney about how FERC was going to rule in the case before the order was issued on January 12. “I'm going to be discussing that with my staff,” McIntyre said during a media briefing following the Commission's January 18 meeting.

The outside attorney is William Scherman, a former general counsel at FERC and chair of the energy regulation and litigation practice at the law firm Gibson, Dunn & Crutcher LLP. Scherman has represented FirstEnergy in other matters, and the case of the proposed power plant sale involves FirstEnergy subsidiaries Monongahela Power Co., a regulated utility in West Virginia, and Allegheny Energy Supply Co. LLC, a power marketing company that owns the Pleasants Power Station.

The FERC order (EC17-88, ES18-4) was issued on January 12, the same day Commissioner Neil Chatterjee issued a notice to report an ex parte communication in the case between himself and Scherman. Chatterjee said Scherman contacted him on January 11 “indicating his concern that the Commission would shortly issue an order adverse to the interests of Monongahela Power.” Scherman also indicated a preference that FERC set the issue for hearing instead of issuing an adverse order rejecting the utility's application outright, Chatterjee said in his statement.

“As soon as I realized that Mr. Scherman's communication concerned the merits of the contested proceeding, I terminated the communication and did not respond to Mr. Scherman's statements,” Chatterjee said.

Scherman maintains that he did violate any rules and pointed to a previous statement that the Commission's ex parte regulations need to be updated. “Based upon my experience, I do not believe I engaged in any ex parte communications,” he said in an email.

Ex parte rules can differ among state and federal agencies, but in general they prohibit parties participating in a contested proceeding from having off-the-record communications with commissioners or decision-making staff in that proceeding.

Scherman asserted that ex parte rules often prohibit commissioners and staff from discussing important policy issues and shield them from relevant information that should be shared in an open and transparent manner. Such rules “are mostly gray, difficult to enforce and serve to cut off federal and state commissioners from vital information,” he said. “These are analog rules in a digital age,” that are outdated and in need of revision, he said.

Scherman made similar comments in a 2015 guest commentary for *The Energy Daily* that he wrote with attorney Jennifer Mansh of Gibson Dunn. They argued for revised ex parte rules that allow more sharing of information while maintaining the integrity and fairness of the decision-making process, highlighting the need for change within FERC's enforcement proceedings.

"In the Twitter era, where communications already occur in ways never anticipated, wouldn't it be better if more open communications to regulators were generally permitted and reported in an open and transparent manner?" Scherman and Mansh wrote.

FERC has addressed ex parte rules over the years, but it has been a while since the last iteration, a final rule (RM98-1) issued in 2000. FERC commissioners and staff provide notice of off-the-record communications in challenged proceedings, and the rules call for sanctions or suspensions from practicing at FERC if a violation is found.

At the media briefing following the January 18 meeting, McIntyre said "Commissioner Chatterjee did exactly the right thing," by reporting the communication with Scherman. The rules that FERC has in place for such situations "worked perfectly," and "as far as I'm concerned, I'm very satisfied with where it came out," McIntyre said.

When asked if he is concerned about FERC staff leaking information before an order is issued, McIntyre said he would be discussing the issue with staff.

He added that he considers Scherman a terrific lawyer and good friend. "In this instance I've had no contact with him on the matter that you raised," he said in response to a reporter's question.

In his email, Scherman noted that he has been involved at FERC and known FERC commissioners over the past 30 years. He said Chatterjee is thoughtful and dedicated to doing what is right for the American people. "Based upon his short time at FERC, it is apparent to me that Neil Chatterjee will be one of the finest members the Commission will ever have," Scherman said.

An attorney who asked not to be named noted that the timing of the communication raises questions about how Scherman knew what type of order might be issued. The communication so close to the order issue date makes it likely that any tips could have come from commissioner staff offices, rather than the Office of General Counsel or other FERC staff that prepare orders well in advance of commissioner votes, the attorney said.

The order in the FirstEnergy case was issued notationally, so it would not have been discussed by staff as part of an open meeting agenda gathering, the attorney added.

In the proposed transaction under the Federal Power Act (FPA), Monongahela Power sought permission to buy the coal-fired power plant from its affiliate. The Pleasants facility is a 1,159-MW plant in Willow Island, West Virginia, that the utility aimed to purchase following a request for proposals (RFP) process overseen by consulting firm Charles River Associates.

In a move hailed by the Electric Power Supply Association and others who support competitive markets and challenged the utility's application, FERC denied the transaction because the applicants did not demonstrate that it was in the public interest. The order sided with consumer advocates and others who said the deal would foist unnecessary costs upon utility customers, ruling that the RFP process was slanted to favor the purchase of the Pleasants facility and did not meet FPA rules guarding against cross-subsidization among affiliates.

By Tom Tiernan TTiernan@fosterreport.com

CONGRESS

House Members Hear Views on Bills Addressing PURPA and LNG Exports

Partisan comments among Republican and Democrat lawmakers and differing views among government and industry witnesses were on display January 19 at a House of Representatives' subcommittee meeting on three bills, two of which deal with LNG exports.

Republicans and several energy industry representatives expressed support for the bills, with witnesses from FERC and the Department of Energy (DOE) raising no objections to the measures, while Democrats and a few witnesses questioned the need for the bills and opposed them. Those touting the bills noted the prolific natural gas production gains made, economic benefits of increasing LNG exports and a need to ease regulatory reviews, while opponents questioned the impact on domestic natural gas prices, removal of consumer protections and stopping DOE from ensuring that LNG exports to non-Free Trade Agreement countries are in the public interest.

Members of the energy subcommittee under the House Energy and Commerce Committee did not discuss a plan for moving the legislation through the chamber during the lengthy hearing, which was interrupted for votes as the deadline for a government shutdown loomed.

Besides the LNG bills, the subcommittee and witnesses addressed a bill (H.R. 4476) to modernize the Public Utility Regulatory Policies Act (PURPA) introduced by Rep. Tim Walberg (R-Mich.). Electric utilities and state regulators expressed support for the bill that would eliminate problems such as developers of small renewable power projects disaggregating large facilities into multiple projects to meet Qualified Facility(QF) requirements and mandatory purchases of their output by utilities.

The provisions of the bill would bring PURPA in line with the realities of the current power generation market, where competitive procurement and renewable portfolio standards have brought more renewable resources and lower costs to utility customers, without mandatory power purchases by utilities that do not need more resources, witnesses said.

Some QF developers "have been able to work around the FERC small renewable QF criteria by disaggregating their projects into multiple smaller projects, thereby availing themselves of more advantageous avoided cost calculations to the detriment of retail ratepayers," said Travis Kavulla of the Montana Public Service Commission on behalf of the National Association of Regulatory Utility Commissions (NARUC). NARUC supports the bill's provisions that substitute PURPA's mandatory purchase obligation with a competitive process and lowers the exemption for nondiscriminatory access to the grid to projects with a capacity of 2.5 MW compared with the current exemption of 20 MW, Kavulla said in his testimony.

The LNG bills, both of which were introduced by Rep. Bill Johnson (R-Ohio), are Unlocking Our Domestic LNG Potential Act (H.R. 4605) and Ensuring Small Scale LNG Certainty and Access Act (H.R. 4606). The latter bill would put into law some of what DOE suggested in a proposed rule on small scale LNG facilities, with DOE reviewing comments and aiming to publish a final rule soon, said Steven Winberg, assistant secretary for fossil energy at DOE.

When questioned by lawmakers, Winberg acknowledged that the oil and natural gas production capabilities in the U.S. is large, with forecasted LNG exports of 2.3 Bcf/d in 2018 and 4.6 Bcf/d in 2019 making only a small fraction of domestic resource base. Lawmakers commented that the LNG bills would boost the capabilities for natural gas exports, similar to what lifting the ban on domestic oil exports did for U.S. participation in the global oil market.

The U.S. has become the world's largest combined producer of oil and natural gas, with an abundance of resources available for both the domestic use market and for exports, Winberg said in his testimony. The nation became a net exporter of natural gas on an annual basis in 2017, which marked the first time since 1957, he said.

"We continue to support expeditious approval of natural gas exports, which provide both economic and strategic benefits to the U.S. and our allies," he said.

Referring to enhanced production in liquids-rich basins and refinery gains, Rep. Joe Barton (R-Texas) noted that natural gas liquids (NGLs) could be exported to global markets. He questioned whether DOE had an opinion on such a move if he sought a modification to Johnson's bills. Winberg said it was not his place to suggest changes or modifications to Congress.

Johnson and other Republicans commented on how Russia uses its supplies of natural gas to other countries as a political weapon, and increased LNG exports from the U.S. would temper Russia's ability to control countries in Europe and elsewhere. With U.S. LNG cargoes reaching Poland for the first time in 2017, improving the ability to export LNG from the U.S. could reap economic and political dividends, they said.

In his testimony, FERC General Counsel James Danly noted that H.R. 4605 would remove DOE's responsibility for authorizing the import or export of natural gas through LNG facilities.

Approving the bill would provide greater certainty in the permitting process for LNG facilities, said Charlie Riedl, executive director of the Center for LNG.

Technology breakthroughs and increased efficiency at production facilities have unleashed a renaissance that established the U.S. as the world's largest natural gas producer, with ample capabilities to meet domestic usage markets and allow increased U.S. participation in the global LNG market, Riedl said.

Countering those views were Paul Cicio, president of the Industrial Energy Consumers of America (IECA) and some Democrat lawmakers. The benefits of the LNG bills would accrue almost exclusively to the oil and gas industry, while increased LNG exports could raise prices to domestic consumers, Cicio told the subcommittee. By removing DOE's oversight role on LNG exports, H.R. 4605 is an anti-consumer bill that could damage the economy and hinder manufacturing jobs, he said.

Since there is only one small scale LNG export facility that would meet the criteria set out in H.R. 4606 – by Eagle LNG Partners in Florida – that bill would benefit only one company, several lawmakers noted. "That sounds suspiciously like the kind of legislative earmark I thought our Republican colleagues opposed," said Rep. Frank Pallone Jr. (D-N.J.), the ranking member on the Energy and Commerce Committee.

DOE's process for reviewing and approving LNG export applications appears to be working efficiently and effectively, with no reason to alter it, let alone do away with it as proposed in H.R.

4605, Pallone said. "I am particularly concerned that the unrestricted export policy included in this bill could significantly impact domestic natural gas prices and adversely affect American consumers and manufacturers," he said.

Regarding the PURPA legislation, Pallone said the bill would entrench the monopoly power of utilities in areas of the country without competitive retail or wholesale power markets.

Similar views were expressed by Karl Rabago, executive director of Pace Energy and Climate Center, on behalf of Rabago Energy LLC, who said H.R. 4476 "would put the utility fox in charge of the small power sector henhouse." Removing the PURPA implementation provisions that have worked well, the bill would empower utilities to essentially eliminate PURPA's procurement requirements from small renewable power projects, Rabago said.

FERC General Counsel Danly noted that PURPA established a national policy that electric utilities are required to purchase energy from QFs at rates set by state agencies. The bill would eliminate the nationwide policy and replace it with a state-by-state regime in which state agencies could relieve utilities of their obligation to purchase power from QFs upon certifying to FERC that there is no need for the QFs' output. "This bill would fundamentally alter PURPA and is a question properly assigned to the consideration of Congress," Danly said.

By Tom Tiernan TTiernan@fosterreport.com

Senate Energy Committee Hears Testimony About Grid Resilience

Grid resilience is a declared priority for the Commission, FERC Chairman Kevin McIntyre told Sen. Lisa Murkowski (R-Alaska) at a Senate Energy and Natural Resources Committee hearing on January 23, on the performance of the electric power system in the New England region during the recent winter weather.

McIntyre was responding to Murkowski's question about how long it will take the Commission to act on the information it collects as part of the new proceeding (AD18-7) on grid resilience for regional transmission organizations (RTOs) and independent system operators (ISOs). McIntyre noted that the order initiating the new proceeding includes deadlines of 60 days for RTOs and ISOs to submit information on grid resilience in their regions, and 30 days for rely comments, but declined to give any deadline for when the Commission would act after receiving the information.

Murkowski noted that the Commission has not produced any final conclusions for a price formation review that was begun shortly after the 2014 polar vortex.

The committee held the hearing to examine the performance of the electric grid during a prolonged period of low temperatures during December 2017 and January 2018. McIntyre and Department of Energy (DOE) assistant secretary Bruce J. Walker of the Office of Electricity Delivery and Energy Reliability, along with industry representatives, testified about the stress on the electric grid and high electricity prices in the New England region during the winter weather.

The bulk power system performed relatively well during the cold weather, said McIntyre, even though there was stress in several regions. The 2014 polar vortex taught the energy industry many lessons as winter peak electric demand in 2014 was at record levels and there were unplanned generator shutdowns resulting in extreme stress on the U.S. natural gas system and high electricity prices because natural gas was the marginal fuel for most electricity markets.

McIntyre noted that the Commission took several actions in response to the 2014 polar vortex, and has addressed the increased use of natural gas for electric generation, including issuing Order No. 809 to improve scheduling of transportation service on interstate natural gas pipelines.

While the recent winter weather event resulted in overall peak loads in the New England region slightly below the levels of the 2014 polar vortex, there were no customer outages resulting from any failures of the bulk power system, said McIntyre.

Walker told the committee that the resilience of the electric grid can't be guaranteed without action to recognize the essential reliability provided by a "strategically diversified generation portfolio," because major segments of the economy are totally dependent on electricity.

Walker proposes that DOE build a resilience model that will include a detailed analysis for a single energy infrastructure model of ongoing resilience planning at the state, local, and region levels, and that fills any gaps in those efforts. Walker noted that there is no current funding for such a model, but said he believes building the model should be a top priority for his office.

The use of coal and nuclear power in the New England region during the winter weather event was noted by Sen. Joe Manchin (D-W.Va.) because almost 40 percent of the power used at the height of the cold weather was from coal powered plants. In response to a question by Manchin about coal's importance to the electric grid, Walker said that during the cold weather event the energy markets could have made up for the difference if coal powered plants had not been available. However, Walker explained that each type of power has different resilience characteristics that are important to the grid.

Ranking Member Sen. Maria Cantwell (D-Wash.) asked McIntyre if the Commission's independence is important, and McIntyre said that independence is essential, which he said he had mentioned at his confirmation hearing. McIntyre also said that the Commission's January 8 order on grid resilience was a 5-0 vote, which shows that there are no politics at work in Commission decisions.

By Denise Ryan DRyan@fosterreport.com

NATURAL GAS PROJECTS

FERC Issues Conditional Certificate for PennEast Pipeline, Commissioners Concur and Dissent

The Commission issued a conditional certificate for PennEast Pipeline Co. LLC's (CP15-558) PennEast Project on January 19, with Commissioners Cheryl LaFleur and Neil Chatterjee concurring, and Commissioner Richard Glick dissenting on the ground that the need for the pipeline is outweighed by its harms.

LaFleur Concurrence. LaFleur said in her concurrence that she was persuaded to vote for the project because 90 percent of the project's capacity has been subscribed by state-regulated local distribution companies and natural gas-fired electric generation facilities, which indicates need. The project will have some adverse environmental impacts, but LaFleur noted that the environmental conditions imposed by the certificate will reduce the impacts to an acceptable level.

LaFleur said she and the other commissioners were concerned about the lack of access to some landowner properties, which resulted in incomplete environmental surveys, but that FERC staff's development of a record about the environmental impacts was sufficient to allow for an adequate evaluation of the project.

LaFleur took the opportunity to express her strong support for Chairman Kevin McIntyre's announcement about reviewing pipeline certificate policy, and said the review should include an examination of the needs determination, environmental review process, and landowner engagement efforts.

Chatterjee Concurrence. Chatterjee also agreed that 90 percent of the project capacity being subscribed shows the need for the project, but expressed concern about the impact on landowners. Chatterjee noted that, while there are incomplete environmental surveys for some landowners, the certificate order imposes conditions that require the filing of additional environmental information once survey access is obtained.

Glick Dissent. Glick concluded that there was no proven need for the project because 75 percent of the capacity is subscribed by PennEast affiliates, and the Commission failed to consider other evidence of need when making the determination to grant the certificate.

The pipeline's benefits don't outweigh its harms, said Glick, and the grant of a conditional certificate is an indication that the Commission lacked sufficient evidence of environmental impacts to make a reasonable determination to approve the project. "Congress did not intend for the Commission to issue certificates so that the certificate holders may use eminent domain to acquire the information needed to determine whether the pipeline is in the public interest," he said.

Glick said the Commission is using the certificate process to let pipeline developers go around landowners that don't allow access to their property, and the question of whether landowners should be required to give pipeline developers access to their land is best left to the states to decide.

Project. The PennEast project is designed to move Marcellus Shale gas from Pennsylvania to New Jersey and Northeast states through a 120-mile pipeline from northeast Pennsylvania to Pennington, New Jersey, with about one-third of the planned route in New Jersey. With a capacity of about 1.1

Bcf/d, it is about 90 percent subscribed under long-term contracts with gas utilities, power generators, and other customers, with an expected in-service date in the second half of 2018.[1]

PennEast is being developed by Enbridge Inc., which bought Spectra Energy, NJR Pipeline Co., a subsidiary of New Jersey Resources, UGI Energy Services, SJI Midstream, a subsidiary of South Jersey Industries, and Southern Company Gas, a subsidiary of Southern Company and formerly AGL Resources.

Numerous protests were filed against the project after it was announced, with some protestors asking the Commission for an evidentiary hearing and questioning whether the use of eminent domain was appropriate for the project. The Commission denied the requests for a hearing.

Project Need. In the certificate order the Commission determined that PennEast had sufficiently demonstrated need for the project because 90 percent of the capacity was subscribed. “The fact that 6 of the 12 shippers on the PennEast project are affiliated with the project’s sponsors does not require the Commission to look behind the precedent agreements to evaluate project need,” said the Commission. The Commission concluded that the project met the requirements of the Certificate Policy Statement.

The Commission rejected the claim of several protestors and commenters that the use of eminent domain wasn’t appropriate, and held that Natural Gas Act section 7 authorizes a certificate holder to acquire necessary land by eminent domain once a certificate has been granted.

Rates. The Commission approved PennEast’s proposal of an initial maximum reservation recourse charge of $16.0799 per Dth per month, and an initial usage charge of $0.0024 per Dth for firm transportation service under Rate Schedule FTS. PennEast developed its proposed initial rates based on a total first-year cost of service of $224,270,492. The proposed cost-based rates reflect a straight-fixed variable rate methodology. The FTS reservation rate is designed using the fixed costs of the project and annual reservation design determinants of 13,905,896 Dth. The FTS usage rate is derived using the variable costs of the project and billing determinants of 282,838,500 Dth, based on a 70 percent load factor of the project’s annual design throughput.

The cost of service is based on a depreciation rate of 2.5 percent for pipeline facilities and 4 percent for compression and metering facilities. PennEast proposed a capital structure of 40 percent debt and 60 percent equity. PennEast’s proposed rates to include a return on equity of 14 percent and a cost of debt of 6 percent. PennEast stated that the overall rate of return of 10.8 percent is consistent with the range the Commission has found acceptable for new greenfield pipelines. PennEast’s proposed cost of service also includes a federal corporate income tax rate of 35 percent.

Federal Taxes. The Commission noted that PennEast used a federal corporate income tax rate of 35 percent in calculating its proposed cost of service, and that effective January 2018, the Tax Cuts and Jobs Act of 2017 included a reduction in the federal corporate income tax rate to 21 percent and allowing certain investments to receive bonus depreciation treatment. The Commission said that, because these changes impact PennEast’s proposed cost of service and the resulting initial recourse

[1] For more information, *see*, *PennEast Not Concerned with Revised Environmental Review Schedule from FERC*, FR No. 3133, p. 33, *PSEG Selling Ownership Interest in PennEast to Spectra, Will Remain Shipper*, FR No. 3140, pp. 16-18, *FERC Grants Late Interventions in PennEast Case*, FR No. 3142, p. 39, *Final Environmental Impact Statement Issued for PennEast Project; Company Says FERC Order is Next Federal Hurdle*, FR No. 3144, p. 12, *PennEast to Resubmit Application in New Jersey Following State Agency Action*, FR No. 3156, pp. 10-11, and *PennEast Seeks Prompt Order from FERC to Meet Shippers’ Needs*, FR No. 3162, pp. 11-13.

rates, PennEast was directed to recalculate its initial recourse rates consistent with the new 2018 federal corporate tax law when it files actual tariff records.

Environmental Issues. The Commission noted that there were incomplete surveys of some land because landowners refused access, but the Commission believes it had enough environmental information to make a reasonable determination that there will be adverse environmental impacts of the project, but the conditions in the order will mitigate those impacts. FERC environmental staff will be monitoring the project to assure that it is being constructed in compliance with the certificate conditions, said the Commission.

In a statement responding to the news of the certificate, Maya van Rossum, the Delaware Riverkeeper and leader of the Delaware Riverkeeper Network said, "If anyone thought that new leadership from FERC Chairman Kevin McIntyre or the addition of Commissioner Richard Glick was going to make one bit of difference in the indefensible rubber stamp FERC would grant to all pipelines put before it, they should now be disabused of that notion. From a lack of need to its devastating impacts on the environment, to the demonstrated false, misleading, and missing information provided by the PennEast companies to FERC, there is no way to support approval of this project. And so, our grounds for legal challenge are strong and we will pursue them."

"Approval of the PennEast Pipeline is a major victory for New Jersey and Pennsylvania families and businesses," said Anthony Cox, Chair of the PennEast Pipeline Company LLC Board of Managers, said in a statement. "They will reap the benefits of accessing one of the most affordable and abundant supplies of natural gas in all of North America. PennEast will lower gas and electricity costs, increase reliability, improve air quality, and make the region more competitive for jobs in the coming decades."

Stay. On January 24, Delaware Riverkeeper Network filed a motion to stay any construction pending its rehearing request. Delaware Riverkeeper contends that construction can't go forward without a meaningful environmental analysis under the National Environmental Policy Act (NEPA). The state and federal agencies that are required to take action in the certificate proceedings have failed to submit full records of their decisions. Without such records any aggrieved party would not have a full record on which to appeal, said Delaware Riverkeeper.

Rehearing Request. Also on January 24, Delaware Riverkeeper filed a lengthy request for rehearing of the certificate order on the ground the order failed to meet the requirements under NEPA, and because of the flawed environmental review, the Commission improperly weighed the adverse impacts and the public benefit.

By Denise Ryan DRyan@fosterreport.com

Dominion Cove Point's $147 Million Pipeline Expansion Approved by FERC

FERC on January 23, approved the Eastern Market Access Project of Dominion Energy Cove Point LNG, LP (DECP) (CP17-15), finding the pipeline expansion to serve a power plant and local distribution company in the Washington, D.C. area met the Commission's requirements.

DECP's application for a certificate under the Natural Gas Act (NGA) sought permission to boost capacity by 294,000 Dth/d to meet the needs of Washington Gas Light Co. (WGL) and a proposed natural gas-fired generation facility in Maryland owned by Mattawoman Energy LLC. The company is seeking to meet an in-service date of 9/1/18 for the $147.3 million project, which would add a new compressor station in Charles County, Maryland, expand an existing compressor station in Loudon County, Virginia, and re-wheel another existing compressor unit in Fairfax County, Virginia.

"We are pleased to have the FERC order in hand and we will proceed with the remaining permitting activity," a spokesman for DECP said January 24.

FERC dismissed challenges from landowners and others, concluding that the environmental assessment (EA) of Commission staff correctly considered project alternatives, public safety, noise, and other concerns. Because no new pipeline right-of-way will be required, and the new compression facilities will be on property either owned by DECP or subject to a property interest held by the company, FERC found that the project minimized adverse impacts on landowners and nearby communities.

The order directed DECP to revise its corporate tax structure to be in line with the new tax law and said planned changes to compression costs that will affect expansion and existing shippers should be made no less than 30 days before the project's in-service date.

Meeting that planned in-service date will be a challenge, DECP said in a January 18 letter to the commission. The company sought an order on its 11/15/16 application and noted that seven months had passed since the EA was issued, which is beyond the average time between an EA and a final order.

"At this time, DECP's construction schedule will be severely compressed" to meet the in-service dates in the precedent agreements with WGL and Mattawoman, and any delay in receiving an order "will add significant risks to the project's in-service date," the company told FERC.

Those firm transportation precedent agreements are for 150,000 Dth/d of capacity for WGL with a primary term of 25 years, and 144,000 Dth/d of capacity for Mattawoman with a primary term of 20 years. The companies reached the agreements following open seasons and solicitations for turned back capacity among existing shippers.[2]

DECP said the project was designed to add new delivery points for WGL and the power plant taking service at existing delivery points, enabling the new transportation service while maintaining service to existing customers. "We find that there will be no adverse impact on existing customers or other existing pipelines and their captive customers," FERC said.

The planned Mattawoman facility is a 990-MW, combined-cycle generation facility in Prince George's County, Maryland, about nine miles from the DECP pipeline.

DECP owns the Cove Point LNG terminal in Maryland and an 88-mile natural gas pipeline system connecting the terminal to the interstate pipeline grid, with two existing compressor stations – the Pleasant Valley Compressor Station in Fairfax County, Virginia, and the Loudon Compressor Station in Loudon County, Virginia.

The facilities to be added include a new 24,370 horsepower compressor station in Charles County, Maryland, with two compressor units on DECP property, a new 7,000 hp compressor unit in a new

[2] For past stories, *see*, *FERC Announces EA for Dominion Cove Point LNG's Eastern Market Access Project, Comments Due by July 27*, FR No. 3155, p. 28, and *Dominion Cove Point Files Application for $147 Million Eastern Market Access Project*, FR No. 3125, pp. 13-15.

building at the Loudon Compressor Station, and repurposing three existing compressors providing 11,840 hp of compression at the Loudon Station from back-up use to normal operations.

The project would include a new power distribution center building, a new meter building and electrical infrastructure at the Loudon Station, and other equipment at the planned Charles Station, along with re-wheeling one existing 17,400 hp compressor unit at the Pleasant Valley Compressor Station. Two new delivery taps would be added at a WGL interconnect in Charles County, Maryland.

DECP designed its initial incremental firm transportation base reservation and usage rates to recover the cost of the project in accordance with FERC's certificate policy statement for new pipeline facilities.

The order noted that the monthly reservation charge of $7.8452/Dth and usage charge of 2.56 cents/Dth are based on an annual cost of service of $27.6 million and an annual throughput of about 59 million Dth. The incremental rate at a 100% load factor is significantly higher than DECP current rates. "Under these circumstances, we find that there will be no subsidization of the project by existing shippers," FERC said.

As it has with other pipeline projects recently, FERC noted that the new tax law that went into effect January 1 cut the corporate income tax rate from 35% to 21%, and it ordered DECP to calculate the incremental rate for the expansion project with a revised cost of service at the new tax rate. It said DECP should include supporting work papers and formulas in that filing.

Because the incremental rate for the expansion is quite a bit higher than current firm transportation rates, "it appears that changing the cost of service to reflect the currently applicable federal corporate income tax rate will not render the incremental rate lower than the existing system rate," the Commission said.

Because of the compression being added through the project, DECP said it would file tariff changes addressing fuel retention and electric power cost adjustment charges that will affect expansion shippers WGL and Mattawoman and existing customers on its pipeline. Those changes would be properly addressed in a limited rate proceeding under Section 4 of the NGA and not in the certificate application case, FERC said. It ordered the pipeline to make the changes not less than 30 days and not more than 60 days before the project's in-service date.

Among the parties who commented on DECP's application and the EA, federal, state, and local agencies – including 12 Chambers of Commerce – and 331 individuals provided input. Among the individuals, 120 expressed support and 211 expressed opposition, FERC said.

The Commission found that DECP satisfied and went beyond the requirements for public notice about the project. It declined to extend the comment period on the EA as sought by one individual and ruled that DECP did not provide false information to FERC as claimed by another individual.

Sen. Chris Van Hollen (D-Md.) included a letter from a constituent that asked FERC to postpone action on the project until the Charles County Board of Appeals holds a final public hearing about the zoning for the planned Charles Compressor Station. "While the Commission encourages cooperation between interstate pipelines and local authorities, state and local agencies may not prohibit or unreasonably delay, through application of state or local laws, the construction or operation of facilities approved by this Commission," FERC said.

The order dismissed claims that DECP segmented the project to be considered separately instead of including it with other pipeline facilities, including Dominion Transmission's Leidy South Project. The Commission concluded that the EA appropriately analyzed the Eastern Market Access project as a discrete project, since its purpose, customers and facilities are not related to the other projects.

The expansion project also would not deliver gas to or facilitate the export of gas at the Cove Point LNG terminal, FERC said in response to such concerns. The precedent agreements with the expansion shippers include delivery points along the DECP pipeline that do not include the LNG terminal, it said.

Under a no-action alternative included in the EA, FERC staff said that if DECP did not pursue the project Mattawoman and WGL would likely seek alternative transportation options on other facilities that could result in a greater environmental impact. Pipeline looping of existing facilities would affect more land in a bigger environmental footprint, the order noted, agreeing with the analysis in the EA to not favor a no-action alternative.

The Environmental Protection Agency (EPA) recommended that FERC analyze the cumulative impact to air quality near the Loudon Compressor Station, even though the EA found that there would be no long-term air quality impacts associated with the modifications at the station. The EA said that the activities at the Loudon station would have only minor impacts on air quality related to fugitive emissions. "We conclude that further analysis is not warranted," FERC said in response to EPA.

The order addressed noise complaints from parties, who noted that the EA showed compressor station blowdowns during scheduled maintenance would present noise levels of 60 decibels at 50 feet from the source, which would exceed FERC's 55-decibel limit. FERC said the 55-decibel limit must be met at noise sensitive areas, not necessarily in the immediate vicinity of project facilities. The nearest noise sensitive area is about 1,800 feet from the noise sources at the Charles Compressor Station, accepting the EA's conclusion that the project would not exceed noise limits in noise sensitive areas.

The EA also notes that all blowdowns at the compressor station will be vented through a silencer, FERC added, with the possible exception of a rarely used emergency shutdown.

By Tom Tiernan TTiernan@fosterreport.com

Rover Ordered to Halt HDD in Ohio, Consider Alternate River Crossing Location

FERC staff on January 24 ordered Rover Pipeline LLC to halt horizontal directional drilling (HDD) activities at a planned crossing of the Tuscarawas River in Ohio due to problems encountered at that site.

The letter order (CP15-93) from FERC staff directs Rover to provide information on drilling fluid losses and to conduct a feasibility analysis of alternate crossing locations of the Tuscarawas River using HDD or direct pipe crossing methods for Rover's Mainline B system. "Include a desktop environmental analysis of pipeline routing and relevant permitting for Mainline B that would be required to reach these alternate crossing locations," said Terry Turpin, director of the Office of Energy Projects at FERC.

"We have ceased operations at the Tuscarawas site" a spokeswoman for Rover parent Energy Transfer Partners LP said January 24. "We are continuing our construction activities at all other locations" and have successfully completed 77% of HDD activities for the project, the spokeswoman said.

She declined to address how much of a delay halting HDD activities at the one site would mean for the massive $4.2 billion project. The project involves dual pipelines – Mainline A and Mainline B – along much of its route bringing 3.25 Bcf/d of natural gas from the Marcellus and Utica Shales in Pennsylvania, West Virginia and Ohio into Michigan and connections with other pipelines.

The move from FERC staff follows reports from Rover and concerns from the Ohio Environmental Protection Agency about the loss of circulation of drilling fluids, which could indicate a problem or possible leak of drilling fluids. The Ohio EPA in early January asked FERC to order Rover to abandon the HDD site at the Mainline B crossing under the Tuscarawas River in Stark County, Ohio, close the pilot hole and consider a new river crossing site.[3]

In his letter to Rover, Turpin said FERC staff appreciates Rover's cautious approach to HDD activities at the Mainline B site, and that the Commission expects that approach to continue. Rover has followed the HDD contingency plans approved by FERC to address the loss of drilling fluid at the site, but no approach tried thus far has been completely successful, he said.

A loss of drilling fluid is not the same as a release or spill of fluid, which Rover experienced previously, but indicates that drilling fluid circulation is not taking place as expected.

"While our understanding is that no fluid has reached the surface, and no impacts on sensitive resources have been documented, the difficult geology at the crossing warrants investigation into other approaches prior to advancing the HDD pilot drill as well as before the subsequent reaming passes," Turpin said. He said construction crews should halt advancement of the pilot hole cutter and that Rover should provide details on how it plans to address expected drilling fluid losses to subsurface formations at the entry and exit side of the HDD site.

Among the information sought is whether a direct pipe crossing of the Tuscarawas River at the current HDD site is feasible.

The geology in the area has presented a challenge, as when construction of Mainline A was taking place in 2017 and FERC halted HDD activities under the Tuscarawas River following the release of about 2 million gallons of bentonite-based drilling fluid covering more than six acres of wetland. That is just one of the incidents that has made Rover's construction controversial, with charges of violations of environmental regulations in Ohio and Michigan, a FERC staff investigation, stopping all HDD activities and instructions for Rover and its contractors to improve HDD construction compliance.

Two different portions of the project have been placed in service, moving gas to different markets while final construction efforts in Ohio continue. Rover began service on Phase 1B of the project on 12/15/17, after service on Phase 1A began on 8/31/17. The remaining portion and the full 3.25 Bcf/d project are expected to be in service by the end of the first quarter of 2018, though that does not take into consideration any possible delay associated with the latest work stoppage in Ohio.

The head of the Ohio EPA on January 24 asked FERC to have Rover cease HDD operations under the Tuscarawas River, registering opposition with Rover's attempt to follow a contingency plan and continue drilling. Following a conference call with officials from FERC and Rover, Ohio EPA Director Craig Butler

[3] For past stories, *see*, *ETP Defends Rover Pipeline Construction Amid Latest Issue Raised by Ohio EPA*, FR No. 3182, p. 29, *Ohio EPA Tells Rover to Clean Up its Act, Again, While Pipeline Updates HDD Activities*, FR No. 3176, pp. 6-8, and *Will Rover Construction Make it Harder for Other Pipeline Projects?* FR No. 3159, pp. 1-5.

said Rover has encountered a new formation where drilling returns are diminished by 78%, with estimated losses of up to 71,809 gallons of drilling fluid.

"FERC should require abandonment of the current installation because of the very similar problems encountered during Line A installation, resulting in a discharge of millions of gallons of drilling fluid to highly sensitive wetlands and threatening the local water supply to nearby residents," Butler said in the letter.

By Tom Tiernan TTiernan@fosterreport.com

NATURAL GAS RATES AND TARIFFS

Southern Star Modifies Proposed Tariff Filing in Response to Protests

Southern Star Central Gas Pipeline Inc. (RP18-276) told the Commission on January 23, that it is willing to revise its proposed tariff language to respond to concerns raised in separate protests by Chesapeake Energy Marketing LLC, and Indicated Shippers.[4]

Southern Star says the proposed change is to address a significant operational issue -- that other pipeline transporters were refusing to accept natural gas from Southern Star because of gas quality issues. There is no proposal to modify the general gas quality specification in the tariff, said Southern Star, and the proposed change is only intended to address an issue for a specific segment.

On January 25, Indicated Shippers filed a response to Southern Star's proposal, saying it was not sufficient to resolve all Indicated Shippers' concerns, but that they are willing to enter into further discussions with Southern Star without any waiver of rights.

Indicated Shippers asks the Commission to suspend the proposed changes for the maximum period and set the proceeding for technical conference.

Tariff Filing. In its 12/27/17 request to update certain tariff sheets, Southern Star said it needs to revise Section 3.2(j) to address situations when the quality of gas received into its system may not be acceptable for downstream deliveries.[5] To address those situations, the proposed change would allow Southern Star to post notice on its customer website on occasion, when operationally necessary, of different gas quality limits to enable downstream deliveries. It vowed to provide as much notice as possible, striving to post notices at least 10 days before the beginning of any month in which a limitation would be effective.

Protests. Southern Star would have too much discretion to change its gas quality specifications under the proposed tariff revision, which should be rejected, Chesapeake and Indicated Shippers said in their January 8 protests.

In its January 23 answer, Southern Star says it will narrow the proposed language related to downstream interconnects by eliminating the notice and posting requirements that Chesapeake objected to. Southern Star also says it will further limit the provision to non-hydrocarbon related gas

[4] Indicated Shippers are BP Energy Co. and ConocoPhillips Co.

[5] For more information, *see*, *Shippers Challenge Southern Star Tariff Request on Gas Quality Standards*, FR No. 3181, pp. 9-11.

quality specifications and only to downstream interconnects with interstate and intrastate pipelines with tariffs or statements of operation conditions that were filed with and approved by the Commission.

Southern Star notes it has initiated discussions with the protestors, and says these additional proposed changes respond to all the issues raised in the protests. Southern Star asks the Commission to accept its answer and approve the tariff filing.

By Denise Ryan DRyan@fsoterreport.com

Shippers Respond to West Texas's Opposition to Protests of Market-Based Rates

Targa Liquids Marketing & Trade LLC and Indicated Shippers[6] responded on January 19, to West Texas LPG Pipeline LP's[7] (OR17-19) answer to their separate protests of WTXP's application to the Commission for market-based rates.

WTXP sought market-based rates for transportation of what it termed a demethanized mix, or ygrade, mixture of NGLs from which methane has been removed, usually involving ethane, propane, butane, isobutane, and natural gasoline. The demethanized mix is transported from processing plants in the Permian and Barnett Shale areas in Texas and New Mexico to fractionators that convert the mix to individual purity products that are used for commercial purposes.

Indicated Shippers. WTXP's answer to the protests contains material errors of fact and law, said Indicated Shippers in their January 19 answer, and claimed WTXP's response is adding to the problems in the application rather than providing clarification.

Indicated Shippers argued that WTXP misstates the law and misconstrues Indicated Shippers' position in the protest, and asked the Commission to reject the application or in the alternative to set the application for hearing.

WTXP erroneously claims that because it has complied with the technical requirements of filing the application under the Commission's Part 348 regulations, it should be granted the authority, but there are substantive deficiencies in the application, said Indicated Shippers.

Indicated Shippers also argued that WTXP failed in its burden of proving that it lacks market power, and attempts to shift the evidentiary burden to the protestors by claiming the protestors have a duty to propose an alternative position for WTXP. WTXP failed to present evidence that it is required to provide for its application, said Indicated Shippers, and attempting to require Indicated Shippers to provide alternatives without having any data provided by WTXP is untenable.

Targa. WTXP failed in its response to identify any new issues it claims were raised by the protests, said Targa, and the response is "little more than a wholesale rejection of the arguments and issues raised by" the protestors and impermissibly supplements the application.

WTXP's response should be rejected because it fails to identify any misstatements by Targa and only mischaracterizes the protest and takes certain statements out of context, said Targa. Targa also

6 Indicated Shippers include: Anadarko Energy Services Co.; Chevron Products Co., a division of Chevron U.S.A. Inc.; Devon Gas Services LP; Occidental Energy Marketing, Inc.; and XTO Energy Inc.

7 WTXP is jointly owned by ONEOK and Martin Midstream Partners.

argues, much liked Indicated Shippers, that WXTP's response improperly tries to shift the burden of proving WTXP lacks market power to Targa. Specifically, Targa said WXTP "chides protestants for failing to prove or provide sufficient evidence to demonstrate that alternatives WTXP" says are good are in fact bad.

WTXP's Initial Response. In a January 4 answer to the protests, WTXP said that the protests were not supported by facts and rely on arguments that have been rejected by FERC in other market-based rate cases.[8]

A key flaw in the shipper protests is that they failed to address the basic question of whether a sufficient percentage of pipeline customers have access to competitive alternatives to defeat any attempted exercise of market power by WTXP. As the significant investment in infrastructure in WTXP's origin and destination markets shows, there are plenty of alternatives available to shippers, with more being added, said WTXP.

By Denise Ryan DRyan@fosterreport.com

FERC Trial Staff Opposes Summary Disposition in Alliance Tariff Case

The Commission's trial staff told the Commission on January 22, that it should not grant Alliance Pipeline LP's (RP15-1022; RP18-175; RP18-181) motion for summary disposition in a tariff case, because there are still outstanding issues to be resolved, even though the only protestor withdrew from the proceeding.

Also on January 22, trial staff filed a separate response to Pecan Pipeline Inc.'s motion for a determination of the scope of the hearing on gas processing issues, or in the alternative for summary disposition, with trial staff arguing that Pecan's motion about the hearing scope is an impermissible attack on the Commission's 2016 remand order, and the alternative request for summary disposition was premature.

Alliance filed a motion on January 5, for summary disposition of its tariff case after protestor Badlands NGLs LLC withdrew from the proceedings.[9] FERC trial staff, in a 12/29/17 filing, opposed Alliance's earlier motion to terminate the proceedings following Badlands' withdrawal, telling the administrative law judge that the issues set for hearing were still unresolved and that a prehearing conference should be convened to determine the next steps in the proceeding.

On 12/19/17, Badlands elected not to proceed with its protest of Alliance's proposed tariff filing, and filed a notice to withdraw. On 12/20/17, Alliance Canada Marketing LP, BP Canada Energy Marketing Corp., and Pecan Pipeline filed a joint motion stating they didn't object to Badlands' withdrawal, but they requested that the proceeding be terminated with prejudice as a precautionary measure to protect confidential information and prevent the companies from having to relitigate the issues raised by Badlands.

Order. Administrative Law Judge Clark S. Cheney issued an order January 2, granting trial staff's request by holding Badlands' withdrawal in abeyance and scheduling a prehearing conference for January 17.

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[8] For more information, *see*, *West Texas LPG Pipeline Says Market-based Rate Protests Ignore Facts*, *FERC Precedent*, FR No. 3181, pp. 23-25.

[9] *See*, *Alliance Moves for Summary Disposition After FERC Staff's Opposition to Termination in Tariff Case*, FR No. 3181, pp. 27-29.

Trial Staff's Response. In the January 22 opposition to Alliance's motion for summary disposition, trial staff argues that the gas processing issue that is set for hearing is still relevance regardless of the withdrawal of Badlands. Trial staff notes that it has not started discovery, and a summary determination would be premature.

There are material issues of fact about the gas processing issue, and summary disposition is not appropriate at this point in the proceedings, says trial staff. The issues are very fact intensive, said trial staff, and it must be given the opportunity to proceed with discovery before the ALJ can make a determination about whether there are any genuine issues of material fact.

Trial staff explains that, while Alliance claims the Commission doesn't have jurisdiction over the extraction agreements that Alliance has with its affiliate Aux Sable Liquid Products LP, the issue of jurisdiction can only be settled following discovery.

In its answer to Pecan's motion for a hearing scope determination, trial staff contends that the Commission already narrowed the scope of the hearing in the 2016 remand order, and that Pecan is only seeking a ruling that as a U.S.-only shipper on Alliance, it's contracts with Alliance's affiliate Aux Sable are not within the Commission's jurisdiction.

Trial staff notes that Pecan failed to request a rehearing of the remand order, and in the order the Commission didn't adopt any of Pecan's arguments. Removing the contracts of Pecan and Aux Sable from the proceedings would be in conflict with the Commission's determination in the remand order, says trial staff.

In the alternative, Pecan asked for summary disposition that its contracts with Aux Sable are not subject to the Commission's jurisdiction, trial staff says, but because discovery is necessary to address the issue and Pecan has failed to produce any facts to support the motion, Pecan's motion should be denied.

By Denise Ryan DRyan@fosterreport.com

OIL PIPELINES

Stateline Crude Files Petition for Declaratory Order With FERC

Stateline Crude LLC (OR18-11) filed a petition for a declaratory order with the Commission on January 16, to approve the tariff and rate structure for its new pipeline system that is currently under construction in western Texas and southern New Mexico.

Stateline[10] asks the Commission to grant the petition by 3/16/18, so that Stateside can meet its transportation obligations. The new project will gather and transport crude oil produced in the Delaware Basin from origin points in Eddy County, New Mexico, and Reeves and Loving Counties, Texas, to interconnections with two downstream pipelines, the Plains Pipeline LP in Reeves and Loving Counties, and the Rangeland RIO Pipeline in Loving County.

[10] Stateline is owned by Catalyst Midstream Partners, LLC, which is a joint venture between affiliates of WPX Energy Inc. and Howard Midstream Energy Partners, LLC.

Requested Rulings. Stateline requests the Commission declare that: the open season process was appropriate; the crude petroleum dedication and transportation agreement (CPDTA) is just and reasonable; adjustments may be made to the committed rates under 18 C.F.R. 342.3; Stateline can recover compliance costs for a change in law; upon filing the committed rates and any adjustments will be approved as settlement rates; the tiered committed rate discounts are consistent with the Interstate Commerce Act; the prorationing provisions are just and reasonable; the option of extending the primary term of the CPDTA for one-year terms is not unduly discriminatory or preferential; and Stateline may add receipt points on the project.

Open Season. Stateline conducted an open season from 12/8/17 to 1/8/18, which provided potential shippers with an opportunity to make minimum volume commitments for transportation service for a minimum five-year term. The offered rates are in the proposed throughput and deficiency agreement. A proposed CPDTA was offered during the open season, giving potential shippers an opportunity to dedicate volumes produced from a minimum specified acreage for transportation service for a minimum 10-year term.

No shipper executed an agreement during the open season, but Stateline says that prior to the open season its affiliate RKI Exploration & Production, LLC, agreed to the terms in the CPDTA, and the commitment was sufficient for Stateline to complete construction of the project.

CPDTA. The CPDTA provides that committed shippers agree to dedicate volumes produced from a minimum specified acreage for transportation service for a minimum 10-year term, and can extend the primary term for additional one-year terms. Stateline says it offered tiered committed rates that vary based on duration and acreage associated with the shipper's commitment, with lower rates available for shippers making long-term, large acreage commitments.

Prorationing. Stateline says its prorationing policy provides that, as long as a committed shipper's rate exceeds the then-current uncommitted rate by $0.01 or more per barrel, the committed shipper's minimum volume commitment will not be subject to prorationing except when the pipeline's available capacity is insufficient to transport all committed shipper volumes.

Uncommitted Shippers. Stateline explains that it plans to establish an uncommitted shipper's rate at $0.01 below the lowest committed rate, and intends to support the uncommitted rate by either filing cost of service data or an affidavit under 18 C.F.R. 342.2. The project reserved at least 10% of its design capacity for uncommitted shippers.

By Denise Ryan DRyan@fosterreport.com

BridgeTex Tariff Accepted, Set for Hearing by FERC; Petition Held in Abeyance

BridgeTex Pipeline Co. LLC and Occidental Energy Marketing Inc. (IS18-102, OR18-6, OR18-3) will be able to hash out their argument about an expansion of the BridgeTex system and whether the oil pipeline violated the Interstate Commerce Act (ICA) at a hearing.

FERC on January 19, accepted and suspended BridgeTex's tariff filing related to an expansion and capacity rights with an effective date of 1/1/18, subject to refund, so that BridgeTex can fulfill its obligations under the transportation service agreements (TSAs) with committed shippers on the expansion. The tariff filing was set for hearing and the hearing was held in abeyance pending the outcome of settlement judge procedures, FERC said in the order.

The petition for a declaratory order filed by BridgeTex on 10/30/17 was held in abeyance pending the outcome of the hearing. The same ruling was made regarding Occidental's complaint against BridgeTex, which was filed on 11/21/17.

Besides capacity rights and expansion issues, a contract interpretation of Occidental's original TSA with BridgeTex will be examined in the hearing and settlement proceedings, FERC said. The contract interpretation appears to hinge on the definition of carrier facilities, and whether certain words in the definition apply to the original BridgeTex system – as argued by the pipeline – or an expansion project, as argued by Occidental, FERC said.

"The subject language is not clear on its face and therefore extrinsic evidence to ascertain the intentions of the parties needs to be examined to resolve the conflict. Such an examination is best accomplished at a hearing where parties will have the opportunity to introduce evidence and cross-examine witnesses," the Commission said in the order.

FERC encouraged the companies to try and reach a settlement, noting that they could request a specific judge to preside over settlement discussions if they can reach agreement on a judge and make their request within five days of the order.

The expansions of the BridgeTex system that moves oil out of the burgeoning Permian Basin to the Houston Gulf Coast area prompted the heated exchange between Occidental, an anchor shipper that took a large chunk of capacity on the original system, and BridgeTex, which is owned by Magellan Midstream Partners LP and Plains All American Pipeline LP. The capacity of BridgeTex in 2014 was 300,000 barrels/day, with an expansion boosting that to 400,000 b/d. For that expansion, the BridgeTex II Expansion Project, the pipeline relied on terms of TSAs and filed committed rates with FERC with the additional capacity subject to new prorationing procedures applicable only to the expansion and not the entire system, seeking an effective date of 1/1/18.

A subsequent expansion that followed an open season is to boost the capacity to about 440,000 b/d and add a new origin point at Midland, Texas, to transport crude oil and a new condensate grade out of the Permian Basin. That subsequent expansion is expected to be operational in early 2019.

In its complaint and protest of the BridgeTex tariff filing, Occidental claimed that the BridgeTex II Expansion prorationing policy discriminates against it in violation of the ICA by separately prorating the expansion capacity to the advantage of expansion committed shippers who participated in the expansion open season, and to the disadvantage of an existing committed shipper like Occidental.[11]

In its petition for a declaratory order approving the tariff, rate structure, and terms of service for the BridgeTex II Expansion, the pipeline asked FERC to rule that its declaratory orders issued for its original system and rate structure were not affected by the expansion. BridgeTex asserted that the committed rate in the expansion does not discriminate against Occidental, since FERC has made clear that it will honor committed rates agreed to by shippers in a valid open season, and that Occidental had the chance but declined to participate in the open season for the BridgeTex II Expansion.

Occidental claims that its original TSA should govern transportation service on BridgeTex "carrier facilities," with the original tariff, rules and regulations applying to all capacity, including additional tranches from improvements, FERC related in the order. The shipper filed a complaint with the Texas Railroad Commission about the addition of a Midland origin point and the planned different treatment of similarly situated shippers in intrastate and interstate service, FERC noted.

BridgeTex asserted that Occidental cannot deny expansion service to shippers who participated in the open season and signed TSAs as offered by the pipeline. Occidental has no basis for its claim to be entitled to a lower rate as an original shipper, since an Occidental affiliate sold its 50% interest in BridgeTex for more than $1 billion, the pipeline said.

The pipeline said nothing in Occidental's TSA grants it the right to superior access to capacity compared with other BridgeTex shippers, with no authority for the alleged rights other than the definition of carrier facilities in its TSA.

The various pleadings show that there are conflicting views on the respective contractual rights and obligations associated with the BridgeTex II expansion, FERC said. BridgeTex is simply trying to implement the bargain struck between it and committed shippers through the TSAs following the expansion open season, pointing to prior FERC orders that said committed shippers from different open seasons are not similarly situated, and may be treated differently.

Conversely, Occidental is arguing that it has been denied access to the BridgeTex system under the rights of its own TSA and the original pipeline tariff, which obligates BridgeTex to provide service at a rate, and subject to a prorationing policy, consistent with the contract. The shipper is asserting that BridgeTex is trying to "carve up capacity on the same pipeline system along the same route into tranches of capacity with different rated and terms and conditions of service," contrary to the ICA and FERC policy.

The Commission found that the case presents issues of fact that cannot be determined based on the pleadings, with a hearing needed to resolve them. While it is not the only issue raised, a significant element is the contractual interpretation of Occidental's TSA with BridgeTex and the definition of carrier facilities, FERC said.

The order granted BridgeTex's request to accept and suspend the tariff filing, subject to refund, with the 1/1/18 effective date so that the pipeline can fulfill its obligations under expansion service TSAs with committed shippers.

[11] For past stories, *see*, *BridgeTex Responds to Occidental Energy's Protest Over BridgeTex II Expansion*, FR No. 3180, pp. 27-29, and *Occidental Energy Protests BridgeTex's Petition for Declaratory Order for Expansion Project*, FR No. 3176, pp. 28-30.

As noted, the petition for declaratory order and complaint were held in abeyance, with the cases consolidated and subject to the outcome of the hearing and/or any settlement.

"The Commission will be able to appropriately address the merits of the regulatory rulings sought in the petition for declaratory order after the contractual rights of the respective parties are resolved by the hearing," FERC said.

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CANADA

NEB Officials Explain Outlook of Fossil Fuel Use Peaking in 2019, Then Flattening

With the National Energy Board's (NEB) long-term outlook showing fossil fuel use peaking in 2019 and then flattening over the next 20 years, NEB officials on January 23, described some of the factors that went into the board's forecast.

Provincial and federal regulatory policies on climate change and carbon pricing, energy efficiency gains that have tempered demand, gains in renewable resources for power generation, phasing out of coal-fired generation and moderate oil and natural gas prices are among the issues examined in the outlook, they said at an event hosted by the Center for Strategic and International Studies (CSIS).

Oil production in Canada, the fourth largest oil producer in the world, has remained robust in a lower price environment, while "a lot is changing, a lot is evolving" in the provinces, said Abha Bhargava, director of energy integration at NEB. Provincial fuel policies can reflect concentrations of different resources available in the regions, with hydropower, nuclear generation, oil and natural gas and renewables representing a diverse resource mix nationally, Bhargava said.

The annual outlook from the NEB examines consumption and production trends, technology developments, utility generation plans, regulatory policies and other issues to reach three different scenarios by 2040. The reference case is based on current economic, climate and energy policies, while the higher carbon price case considers the impact of carbon pricing that increases in the long term, and the technology case includes carbon pricing along with adoption of emerging technologies, larger gains in electric vehicles and solar power compared with the other two cases, explained Matthew Hansen, technical lead on the Energy Futures report for the NEB.

All three cases of the report show Canada reducing fossil fuel consumption compared with previous versions of the report. The 2017 version is the first reference case in the Energy Futures report series – now in its 50th year – where fossil fuel consumption peaks within the projection period. Energy efficiency gains, rising oil and natural gas prices, climate policies, and vehicle emission standards are among the factors leading to the flattened fossil fuel use, said Chris Doleman, co-project manager on the report at the NEB.

Oil prices in the reference case, expressed in 2016 dollars, reach (U.S.) $80/barrel by 2027 and stay at that level through 2040, with price gains early in the forecast period bringing increased production to balance supply and demand, according to the report, which was released in the fall of 2017.

By 2040, Canadian crude oil production in the reference case is 6.3 million barrels/d, which would be 59% above the 2016 level of 4 million b/d. Production expectations are lower in the higher carbon price case. In the technology case, technology gains in the production sector allow production levels to be the same as in the reference case, even with a forecast of lower oil prices in that scenario, said Hansen.

Oil sands production, at nearly two-thirds of total Canadian oil production in 2016, is expected to make up most of the production growth over the forecast period, reaching 4.5 million b/d in 2040, a 77% gain from 2016.

Natural gas production in the reference case dips early in the forecast period, reaching a low of 14.6 Bcf/d in 2023 before climbing in response to a gradual increase in prices. The production gain later in the forecast period will offset production declines from older wells, with a level of 16.8 Bcf/d reached by 2040, which would be the highest level since 2007.

The forecast has Henry Hub natural gas prices similar in all three cases, rising from about $2.45/MMBtu in the early part of the forecast to $4.30/MMBtu in 2040.

At the CSIS event, Bhargava said that price forecasts are a key uncertainty in the NEB projections. Hansen and Doleman noted that the reference case assumes production gains will reach markets and infrastructure will be built as needed. If pipeline infrastructure is not built, rail and other transportation modes could be used to move production to markets, which would impact producers, they said.

A lack of market development for Canadian natural gas could reduce the prices Canadian producers experience relative to Henry Hub prices, which would impact gas production trends in the forecast, Hansen said.

The timing and development of LNG export projects is another uncertainty, with Canadian developers enjoying low-cost feedstock, proximity to Asian markets compared with the U.S. Gulf Coast and cooler Canadian weather, according to the report *Canada's Energy Future 2017: Energy Supply and Demand Projections to 2040*.

Earlier versions of the report assumed some volumes of LNG exports from Canada within the projection period, but the 2017 version assumes that no exports will take place by 2040. The global LNG market is becoming increasingly competitive as more facilities are built around the world, with the high cost of building a new LNG facility and a pipeline to supply it weighing against Canadian LNG export project developers, the report said. Even so, some projects on the East and West Coasts of Canada are still being considered by developers, it said.

By Tom Tiernan TTiernan@fosterreport.com

NEB Denies Maritimes & Northeast Rate Discount, Noting Market Uncertainty

With comments acknowledging the natural gas market uncertainty in the Canadian Maritimes region, the National Energy Board (NEB) on January 22 denied an application from Maritimes & Northeast Pipeline LLC for a discounted rate to keep Irving Oil as a firm transportation shipper.

The decision (RHW-001-2017) leaves Irving free to depart the Maritimes & Northeast system and pursue other gas transportation alternatives for its refinery and cogeneration facility in St. John, New Brunswick, including Emera Brunswick Pipeline Co. Ltd. (EBPC). Maritimes & Northeast asserted that EBPC was a viable bypass threat when it sought the load retention service (LRS) and discounted rate for Irving, claiming that Irving could shift its transportation to EBPC with minimal regulatory oversight from the NEB.

The NEB disagreed with that view. It agreed that EBPC is a credible transportation alternative for Irving, with evidence showing that Irving was offered firm service on EBPC if the LRS application is rejected. But the claim that EBPC could acquire Irving as a shipper with minimal NEB review does not appear to be accurate, since EBPC would have to reverse flows to meet the needs of Irving, and such a request would require a full application and not a streamlined proceeding.

The decision rejected Maritimes & Northeast's application for the LRS as premature, with no finding as to whether the discounted rate for Irving and resulting impact on other shippers would be just and reasonable or result in unjust discrimination.

Maritimes & Northeast is facing a challenging situation, with declining production from the Sable Island Offshore Energy Project and the Deep Panuke offshore platform, the expiration of contracts among some large shippers in 2019 expected to result in revenues falling well short of its cost of service, and any remaining shippers facing much higher rates. The pipeline, which takes gas from offshore Nova Scotia and feeds Canadian markets en route to the U.S. portion and connections with customers in New England, has a capacity of more than 400,000 MMBtu/d, but the expiration of contracts and the precipitous drop in offshore production could result in firm contracts of less than 100,000 MMBtu/d.

The pipeline is owned by Enbridge, with 77.53%, Emera Inc., with 12.92% and ExxonMobil, which operates the Sable Island production facility, with 9.55%.

"We respect the decision of the NEB, but we're disappointed" with the outcome, a spokesman for Maritimes & Northeast told *The Foster Report*. The next step for Maritimes & Northeast will be determined by an NEB decision on its mainline rates for 2017 to 2019, which covers some similar issues, he said.

Searching for positives, the company is pleased that the board provided clarity on the regulatory process that competitor EBPC would have to go through to gain Irving as a customer, the Maritimes & Northeast spokesman said. "We're still concerned that Irving Oil might leave our pipeline system," he said.

The order outlined some of the substantial concerns about the gas market changes and it is clear that NEB members took those concerns into consideration, he added.

Irving's original contract with Maritimes & Northeast expired at the end of 2015 and another one terminated on 10/31/17. It has been meeting its transportation needs on Maritimes & Northeast through non-firm services and the secondary market, the NEB noted.

The LRS would provide the pipeline with about $79 million in revenue over 13 years and about 65,000 MMBtu/d of billing determinants, with a discounted rate for Irving. The revenue to Maritimes & Northeast and billing determinants would benefit all shippers on the pipeline, and those benefits would be lost if Irving leaves the system.

In testimony filed in the proceeding, consulting firm ICF said that the rate reduction for Irving and revenue for the pipeline would not amount to much help for Maritimes & Northeast shippers given the dramatic changes facing the pipeline. "It is like offering life-jackets to passengers on the Titanic after the life boats left," ICF told the NEB.[12]

In its decision, the NEB said Maritimes & Northeast does not know with any certainty what its rate structure will look like after 2019, that it is competing to retain shippers, and has had discussions with other customers about load retention services. The potential for rates to increase beyond what the market would bear because of lost load and lower throughput is real, the pipeline said.

EBPC is in a different situation in that it was built to delivery gas from the Canaport LNG intake terminal, with a contract with Repsol that does not expire until 2034. The pipeline delivers gas to the U.S. market and has never had any delivery points in Canada, meaning if it was to provide service to Irving, it would have to alter flows for deliveries to the refinery and cogeneration complex in New Brunswick.

Irving concluded that EBPC cleared its ability to make an offer for firm service with Repsol and that Repsol has no rights over the capacity that would be offered to Irving, or at least not rights that would affect Irving's ability to use that capacity on a firm basis, the NEB related.

The NEB noted that other parties weighed in on the LRS application, with Nova Scotia Power and Heritage Gas, as captive customers on the Maritimes & Northeast system, facing significantly higher rates if the discount for Irving were to be accepted.

Among the options being considered are having Maritimes & Northeast and/or EBPC meet Canadian customer needs by transporting gas north from U.S. pipeline connections, with costs in competition with other fuel sources from Canada.

The evidence shows that Irving would be expected to pursue the EBPC alternative to meet its needs if the application is denied, the NEB said. Countering Maritimes & Northeast's claim that EBPC could pursue a streamlined proceeding to gain Irving as a customer, the NEB said the criteria for that to happen does not appear to be met.

Among the criteria are that all parties, including shippers, landowners, federal, provincial, and municipal agencies, have been consulted on any application to reverse flows and any concerns have been resolved. EBPC's agreement with Repsol and the NEB's 2016 decision approving that agreement also require EBPC to file an application with the board if it seeks to reverse service on the pipeline.

[12] For a past story, *see*, *Offshore Production Decline Spells Trouble for Maritimes & Northeast Shippers, ICF Tells NEB*, FR No. 3157, pp. 25-26.

The decision deemed the LRS application a premature response from Maritimes & Northeast to the perceived competition from EBPC.

As the hearing on the LRS application was carried out, significant concerns and uncertainties were raised about the future of the gas market in the Maritimes and the impact on pipeline shippers, particularly those captive to Maritimes & Northeast, the NEB said. The evidence that Maritimes & Northeast has discussed LRS options with other customers in the New Brunswick area raises concerns about the impact on pipeline customers and the long-term future of the gas market in the region, the board said.

"The evidence indicates that splitting the domestic market demand between two pipelines post-2019 may challenge the viability of [Maritimes & Northeast], which, as a result, could affect the Maritimes natural gas market unfavourably," the NEB said.

Even with the broad uncertainties at play, it appears that not all parties with a potential interest in such matters participated or submitted evidence in the proceeding, the NEB said. It commented that an examination of different rate and tariff approaches would be more fruitful once Maritimes & Northeast's supply and contract situation are known.

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ENERGY NEWS ALERT

Algonquin Responds to BP's Motion for Clarification or Rehearing of Algonquin's Annual FRQ Filing

On January 25, Algonquin Gas Transmission LLC (RP18-75) filed a response to BP Energy Co.'s motion for clarification or rehearing of the Commission's order accepting and suspending Algonquin's tariff records and establishing a hearing. In its response, Algonquin said that BP's claim that Algonquin has the burden of modifying its methodology for calculating the FRQ deferred account is incorrect, and if BP wants to change a pipeline's rate structure, BP must demonstrate under Natural Gas Act section 5 that the pipeline's existing rates are unjust and unreasonable and propose rates that would be just and reasonable.

Algonquin also said that BP cites various Commission decisions that are distinguishable from this case, and the cases involve relatively simple fixes that are inapplicable to Algonquin's filing (for more information, *see, Repsol Asks FERC to Deny Rehearing Request in Algonquin's Annual FRQ Filing*, FR No. 3180, pp. 20-21).

Gastar Exploration Agrees to Sell Assets in Oklahoma for $107.5 Million

Gastar Exploration Inc. announced January 25, that it has entered into an agreement to divest its interest in the West Edmund Hunton Lime Unit (WEHLU) for $107.5 million to provide capitol to develop STACK acreage. The transaction is expected to close by February 28, subject to customary closing conditions, and have an effective date of 10/1/17.

WEHLU is primarily located in Oklahoma and Logan counties, Oklahoma. During the third quarter of 2017, the WEHLU assets' daily production net to the company was approximately 2,836 Boe comprised of 52% oil, 25% natural gas liquids and 23% natural gas, which constituted 46% of the company's total equivalent production for such quarter.

Russell Porter, Gastar's President and CEO, said in a statement, "This divestiture of our WEHLU assets should provide Gastar with sufficient liquidity to fund our core STACK acreage development plan through 2018. Our one rig drilling program has been re-started and we expect to be able to drill and complete approximately 20 operated wells in 2018 to more fully delineate and develop the Meramec and Osage formations on our 65,200 net surface acres in our core STACK position. Due to our large, contiguous acreage position with as many as six potentially productive formations and multiple benches within certain prospective formations, we have a large inventory of undrilled horizontal locations to exploit to create value going forward."

House Democrats Request Natural Resources Committee Hearing About Zinke's Oil & Gas Lease Plan

Three Democratic members of the U.S. House of Representatives Committee on Natural Resources sent a letter January 24, to Chairman Rob Bishop (R-Utah) requesting a full oversight hearing on the planning process for the Department of Interior's five-year oil and gas leasing plan.

Ranking Member Raúl M. Grijalva (D-Ariz.), Ranking Member of the Subcommittee on Energy and Mineral Resources Alan Lowenthal (D-Calif.), and Ranking Member of the Subcommittee on

Oversight and Investigations A. Donald McEachin (D-Va.), also requested that Interior Secretary Ryan Zinke be required to testify about the program.

Zinke announced in a tweet January 9, that he was removing Florida from the proposed plan to open the entire U.S. outer continental shelf (OCS) to oil and gas leases. In the tweet Zinke said, "I support the governor's position that Florida is unique and its coasts are heavily reliant on tourism as an economic driver. As a result of discussion with Governor Scott and his leadership, I am removing Florida from consideration for any new oil and gas platforms."

The proposal to have over 90 percent of the total acreage in the OCS available for oil and gas exploration and development was announced January 4, by Zinke, as part of the development of the 2019-2024 National OCS Oil and Gas Leasing Program.

In the letter the members note that there are "shifting explanations as to whether the waters around Florida are being consider." Walter Cruickshank, acting director of the Bureau of Ocean Energy Management, said at the January 19 committee hearing that Zinke's tweet about Florida was not a formal agency action, said the members.

The members noted that they requested an explanation from DOI about the process for removing Florida from the plan, but didn't receive an answer (for more information, *see, Zinke Removes Florida From Proposed OCS Oil and Gas Lease Sales*, FR No. 3181, pp. 31-32).

A group of House members from Florida, and the state's two senators sent a letter January 24, to Zinke, opposing the inclusion of Florida in the plan following Cruickshank's testimony that Zinke's exclusion of Florida from the plan was not a formal agency action.

Geospatial Corp. to Use Blockchain Technology for Global Oil and Gas Industry

Geospatial Corp. announced January 24, that it will be integrating Blockchain technology with the company's GeoUnderground service. GeoUnderground is cloud-based locational software platform that allows energy companies a secure way to manage contracts, assure provenance, and track asset maintenance. Geospatial uses integrated technologies to determine the accurate location and position of underground pipelines, conduits and other underground infrastructure data allowing Geospatial to create accurate three-dimensional digital maps and models of underground infrastructure.

Utopia Pipeline Begins Service, Sending Ethane from Utica Shale to Ontario, Canada

Kinder Morgan Inc. on January 23, said the Utopia Pipeline has begun service, delivering ethane out of the Utica Shale region from Harrison County, Ohio, to Windsor, Ontario.

The 270-mile pipeline has an initial capacity of 50,000 barrels/day and can be expanded to more than 75,000 b/d. Utopia provides ethane for a growing petrochemical industry, with Nova Chemicals Corp. as a long-term capacity contract holder.

Peregrine Oil Responds to Texas Eastern's Second Motion to Dismiss Amended Complaint

Peregrine Oil & Gas II LLC (RP18-271) responded on January 23, to Texas Eastern Transmission LP's second motion to dismiss Peregrine's amended and restated complaint. Peregrine had originally filed a complaint in RP17-811 against Texas Eastern on 6/1/17, alleging that Texas Eastern has not maintained its Line 41-A System and cost the company more than $1 million in lost production and damages. Peregrine later amended the complaint to add a new claim about Texas Eastern's maintenance of Line 41-A.

In its January 23 response, Peregrine argues that Texas Eastern's second motion to dismiss should be rejected because it disrupts the ongoing proceedings set for hearing in the Commission's order issued on 10/27/17. Peregrine also contends that Texas Eastern is merely repeating its claims from its first motion to dismiss (for more information, *see, Peregrine Oil Responds to Texas Eastern's Request to FERC to Dismiss Amended Complaint,* FR No. 3181, pp. 20-21).

Plains All American to Begin Construction of Cactus II Oil Pipeline in Texas

A subsidiary of Plains All American Pipeline LP on January 22, announced that it will begin construction of a new crude oil pipeline from the Permian Basin to the Corpus Christi/Ingleside area in Texas following a successful open season.

The planned Cactus II Pipeline would have a takeaway capacity out of the Permian Basin of 585,000 barrels/day, and Plains All American said it has received sufficient customer interest to hold a second binding open season for the project. Origin points for the second open season will be Orla, Wink South, Midland, Crane and McCamey, Texas.

The project will include a combination of existing pipelines and two new pipelines, with the first new pipeline extending from Wink South to McCamey, and the second new pipeline extending from McCamey to the Corpus Christi/Ingleside area.

Permitting, right-of-way, and procurement activities are underway. Subject to regulatory and permitting approvals, the Cactus II project is expected to begin service in the third quarter of 2019, Plains All American said.

FERC Issues Tolling Order for National Fuel's Northern Access 2015 Project

The Commission issued a tolling order on January 22, granting rehearing for further consideration to National Fuel Gas Supply Corp. (CP14-100). A rehearing was timely requested of the Commission's order issued 11/22/17 (161 FERC ¶ 61,210 (2017)).

The Commission held that National Fuel can charge the system-wide fuel rate, and not an incremental rate, as part of its lease agreement with Tennessee Gas Pipeline Co., in the 11/22/17 order on rehearing, but declined to grant National Fuel a predetermination that it could roll any unaccounted-for lease fuel into the system-wide rate for the project.

In a February 2015 certificate order, the Commission authorized National Fuel to construct and operate a new compressor station in Cattaraugus County, New York (Hinsdale Compressor Station); to install a new compressor unit at its existing Concord Compressor Station in Concord, New York; and to modify a measurement and regulator station in Eden, New York (for more information, *see, FERC Approves National Fuel Charging System-Wide Fuel Rate for Northern Access 2015 Project*, FR No. 3176, pp. 19-21).

New Report Examines Effect of Natural Gas Prices on Manufacturing Employment

The decline in natural gas prices between 2007 and 2012, raised overall manufacturing employment by 0.6 percent, a new study, *The Impacts of Lower Natural Gas Prices on Jobs in the U.S. Manufacturing Sector*, that was released by Resources for the Future on January 22, concluded.

The authors noted that popular discussion has held that the manufacturing recovery following the 2008 recession was due to a sharp drop in natural gas prices, but that previous analyses failed to use certain data, and their study shows that the effect of gas prices on manufacturing jobs was much less than previously thought. While the decline in gas prices has had a favorable impact on manufacturing employment, it was considerable less than other studies had found.

FERC Issues Tolling Order for Magellan Midstream's Request for Rehearing of Denial of DO

The Commission issued a tolling order on January 22, granting rehearing for further consideration to Magellan Midstream Partners LP (OR17-2). Magellan asked the Commission on 12/22/17 for reconsideration in the form of a request for clarification or for a rehearing of the Commission's order issued 11/22/17 (161 FERC ¶ 61,219) denying Magellan's petition for a declaratory order.

Magellan is seeking further guidance on the oil pipeline marketing affiliate activities that are permitted under the Interstate Commerce Act. Magellan said it was unclear from the order what activities a marketing affiliate can engage in when the affiliate participates in a pipeline affiliate's open season and signs a TSA (for more information, *see, Magellan's Request for Reconsideration of DO Actually Attempt at Rulemaking, ETP Charges*, FR No. 3181, pp. 21-23).

Columbia Gas Files Answer to Protests of Revised Tariff on Tax Issue

Columbia Gas Transmission (RP18-298) on January 19, filed an answer to protests by Washington Gas Light Co., and the Cities of Charlottesville and Richmond, Virginia, of Columbia's 12/29/17 revised tariff filing implementing a stipulation and agreement in Docket No. RP12-1021 that was approved by the Commission on 1/24/13.

Washington Gas said it was protesting Columbia's failure to implement the recent federal tax change as required by the 2013 settlement. Washington Gas noted that, "although Columbia Gas promises to adjust its filing for the corporate tax rate change, it has not yet done so." The settlement requires Columbia Gas to calculate the capital cost recovery mechanism to include any changes in the federal corporate tax rate.

In the January 19 answer, Columbia acknowledged the error and proposed correcting it so that it is consistent with the settlement by reflecting the new federal tax rate (for more information, *see, Washington Gas Light Protests Columbia Gas Transmission's Revised Tariff on Tax Issue*, FR No. 3181, p. 30).