REPORT OF THE NATURAL GAS REGULATION COMMITTEE

This report summarizes policy developments and legal decisions that have occurred at the Federal Energy Regulatory Commission (FERC or Commission) and the United States Courts of Appeals in the area of natural gas regulation between July 1, 2013, and June 30, 2014.*

* The committee is grateful to the following members for their contributions to this report: Larry Acker, Daniel Archuleta, Andrea Chambers, Patrick Daugherty, Kevin Downey, Patricia French, Tyler Gray, Jasmine Hites, Marcia Hook, Emily Pitlick, Christine Powell, V. Prentice, Randall Rich, Andrew Schulte, Alyssa Schindler, Kevin Sweeney, Michael Thompson, and Sarah Tucker.

I. RULEMAKING ACTIONS

A. Revisions to Procedural Regulations Governing Transportation by Intrastate Pipelines

On July 18, 2013, the FERC issued a final rule revising its regulations on rate filings and the approval process for natural gas pipelines subject to the Natural Gas Policy Act of 1978 (NGPA) or the Natural Gas Act (NGA).[1] The FERC explained that the rule is intended to alleviate unnecessary burdens on regulated industries and to increase regulatory certainty.[2] Prior to the revisions, NGPA section 311 and Hinshaw pipelines[3] had two options for filing rates; namely, (i) basing the rates on the state methodology pursuant to section 284.123(b)(1) of the FERC's regulations, or (ii) applying for the FERC's approval of the proposed rate pursuant to section 284.123(b)(2) of the FERC's regulations.[4] If the pipeline sought the FERC's approval, the proposed rate was deemed approved unless, within 150 days of the FERC's receipt of the pipeline's application, the FERC either extended the time for action or instituted a proceeding, thus inviting comments and arguments from all interested parties.[5] Under the existing regulations, both state-based and commission-approved rates are subject to a mandatory five-year review by the FERC.[6] Finally, before the revision, "a request

1. Order No. 781, *Revisions to Procedural Regulations Governing Transportation by Intrastate Pipelines*, F.E.R.C. STATS. & REGS. ¶ 31,348, 78 Fed. Reg. 45,850 (2013) (to be codified at 18 C.F.R. pt. 284) [hereinafter *Order No. 781*].

2. *Id.* at P 1.

3. *Id*. at P 2 n.4. Hinshaw Pipelines are local distribution pipelines served by interstate pipelines not subject to Commission jurisdiction. Natural Gas Act, 15 U.S.C. § 717(c) (2012).

4. *Order No. 781*, *supra* note 1, at PP 3-5.

5. *Id.* at P 5.

6. *Id.* at P 7.

to withdraw a filing must be filed under [the FERC's] general Rules of Practice and Procedure."[7]

New regulations introduced "optional notice procedures" as an alternative option for processing rate filings by section 311 and Hinshaw pipelines,[8] but they cannot be used for "market-based rate filings by intrastate pipelines or for blanket certificate applications by Hinshaw pipelines."[9] If no objections are filed against the proposed rate within the specified timeframe or, if filed, objections are resolved within a thirty-day reconciliation period, the rate filing is considered automatically approved without FERC order.[10] As with state-based and FERC-approved rates, rates approved through the optional notice procedure must be reviewed by the FERC every five years.[11] Finally, in an effort to reduce the burden on regulated industries, the new rule permits intrastate pipelines with unchanged state-approved rates to satisfy the five-year rate review requirement by filing a certificate of compliance with the requirements of section 284.123(b)(1) of the FERC's regulations.[12]

II. RATES, TERMS, AND CONDITIONS OF SERVICE

A. *Abandonment*

1. *Columbia Gas Transmission, LLC*, 145 F.E.R.C. ¶ 61,028 (2013).

The FERC conditionally approved the joint application of Columbia Gas Transmission, LLC (Columbia) and Columbia Gulf requesting authority for Columbia to acquire 545,635 dekatherms per day (dth/d) of capacity by lease from Columbia Gulf, and for Columbia Gulf to abandon equivalent capacity by lease to Columbia.[13] The FERC found that the proposed lease satisfied the threshold test of the Certificate Policy Statement because Columbia agreed not to recover the leased capacity costs through the primary term of its Modernization Settlement.[14] The FERC praised the proposed lease for enabling Columbia to maintain service to its customers served from Columbia Gulf's system while avoiding unnecessary construction of new facilities.[15] The FERC directed the applicants to remove the provisions of the lease which "allow[ed] Columbia Gulf to access and utilize any leased capacity not being used by Columbia," because "once the capacity is leased, it is subject to the provisions of the lessee's tariff and the lessor has no rights to the leased capacity."[16] The FERC also determined that, "consistent with [FERC]

7. *Id.* at P 8.
8. *Id.* at P 9.
9. *Id.* at P 27.
10. *Order No. 781*, *supra* note 1, at PP 10-11.
11. *Id.* at P 13.
12. *Id.* at P 1.
13. *Columbia Gas Transmission, LLC*, 145 F.E.R.C. ¶ 61,028 at P 1 (2013).
14. *Id.* at P 16. *See also Columbia Gas Transmission, LLC*, 142 F.E.R.C. ¶ 61,062 at P 6 (2013) (approving Modernization Settlement).
15. *See, e.g.*, 145 F.E.R.C. ¶ 61,028 at PP 18, 20, 22.
16. *Id.* at P 23.

policy, Columbia Gulf will be at risk for the recovery of any costs associated with the lease capacity that are not collected from Columbia."[17]

2. *Columbia Gas Transmission, LLC*, 147 F.E.R.C. ¶ 61,116 (2014).

The FERC approved an uncontested settlement among Columbia and the former customers of Commonwealth Gas Pipeline Corporation (Commonwealth) to restructure historic, non-conforming service agreements stemming from Columbia's 1990 merger with Commonwealth.[18] When it approved the merger, the FERC required Columbia to operate "with recognition of the capacity rights of the Commonwealth Customers."[19] The instant settlement included two mechanisms to preserve this directive: (1) Capacity Assignment Agreements, under which Columbia confirmed the customers' interest in the intangible right to Commonwealth's capacity through any necessary assignment of any such interest possessed by Columbia; and (2) Capacity Leases, under which Columbia will lease Commonwealth's capacity from the customers and administer the capacity under Columbia's tariff.[20] The FERC found that the settlement also brought the companies' operations "into a closer alignment with the [FERC's] current regulatory policies,"[21] and granted Columbia and Commonwealth associated abandonment and certificate authority under section 7 of the Natural Gas Act.[22]

3. *Gulf South Pipeline Co.*, 145 F.E.R.C. ¶ 61,139 (2013).

The FERC granted, subject to conditions, the application of Gulf South Pipeline Company, LP (Gulf South) and Petal Gas Storage, LLC (Petal) (collectively, the Applicants) for authorization for Gulf South to construct and operate the Southeast Market Expansion Project, for Petal to abandon firm capacity pursuant to two separate leases, and for Gulf South to acquire the same capacity from Petal by lease.[23] The FERC rejected Gulf South's request for a pre-determination that it could roll the costs of seventy miles of new pipeline into its system-wide rates.[24] Although the FERC accepted Gulf South's proposal to apply separate charges for transportation service over the leased capacity and for service using the incremental mainline system capacity, the FERC required Gulf South to separately record certain costs to prevent existing customers from inappropriately subsidizing new services.[25]

4. *Northern Natural Gas Co.*, 146 F.E.R.C. ¶ 62,108 (2014).

The FERC granted the application of Northern Natural Gas Company, Southern Natural Gas Company, and Florida Gas Transmission Company, LLC

17. *Id.* at P 20.
18. *Columbia Gas Transmission, LLC*, 147 F.E.R.C. ¶ 61,116 at P 1 (2014).
19. *Id.* at P 17.
20. *Id.* at P 15.
21. *Id.* at P 22.
22. *Id.*
23. *Gulf S. Pipeline Co.*, 145 F.E.R.C. ¶ 61,139 at P 1 (2013).
24. *Id.* at PP 30, 41.
25. *Id.* at PP 32, 34-37.

(collectively, the Applicants) to abandon certain jointly-owned offshore and onshore pipeline facilities.[26] The FERC previously denied a request to abandon the same facilities, but granted abandonment here based on the applicants' representations that natural gas production tied to the facilities had dropped drastically since that denial, and the flow rates had become too low to maintain pipeline integrity.[27]

5. *Panhandle Eastern Pipe Line Co.*, 147 F.E.R.C. ¶ 61,043 (2014).

The FERC granted Panhandle Eastern Pipe Line Company, LP's (Panhandle) application to abandon its Mouser Compressor Station in Texas County, Oklahoma.[28] OXY USA, Inc. (OXY) filed a protest asserting that on-system gas producers, relying on the Mouser Compressor Station, would be forced either to re-route their production or leave the Panhandle system.[29] The FERC denied the protest, noting that OXY "is not a shipper on Panhandle,"[30] and finding "it telling that no protests or objections have been raised by any shippers that actually pay for the compression."[31] The FERC further ruled that OXY identified nothing in Panhandle's proposal that would harm shippers' rights to transportation service or access to receipt or delivery points on Panhandle's system.[32] The FERC found the abandonment did not cause any continuity of service issues because the producers upstream of the facilities to be abandoned had other options for continued access to the interstate grid.[33]

6. *Tennessee Gas Pipeline Co.*, 147 F.E.R.C. ¶ 61,196 (2014).

The FERC denied requests for rehearing and reconsideration, and granted clarification of a May 2013 order authorizing Tennessee Gas Pipeline Company's (Tennessee) abandonment by sale to Kinetica Energy Express, LLC (Kinetica) of certain "Supply Area Facilities" located onshore and offshore in the Gulf of Mexico and Louisiana.[34] This summary addresses only the abandonment-related issues in the rehearing order. The FERC affirmed its rejection of the concern of objecting shippers regarding continuity of service after the abandonment. The FERC reasoned that, because the jurisdictional facilities abandoned and transferred by Tennessee will remain available for interstate service from Kinetica, there was no basis not to permit the transfer of the facilities that serve a non-jurisdictional gathering function.[35] The FERC went on to affirm that any "inconvenience of shippers having to deal with multiple transporters or the

26. *N. Natural Gas Co.*, 146 F.E.R.C. ¶ 62,108, 64,230 (2014).
27. *Id.* ¶ 64,230-31.
28. *Panhandle E. Pipe Line Co.*, 147 F.E.R.C. ¶ 61,043 at P 1 (2014).
29. *Id.* at P 16.
30. *Id.*
31. *Id.* at P 22.
32. *Id.* at P 24.
33. *Id.* at P 25.
34. *Tenn. Gas Pipeline Co.*, 147 F.E.R.C. ¶ 61,196 at P 1 (2014), *on reh'g of Tenn. Gas Pipeline Co.*, 143 F.E.R.C. ¶ 61,196 (2013).
35. *Id.* at PP 21-22, 25.

possibility of increased overall transportation costs" are not "an appropriate basis to deny" the proposed abandonment, because "gas commodity markets and contracts for the sale of gas are excluded from our jurisdiction."[36]

7. *Texas Eastern Transmission, LP*, 145 F.E.R.C. ¶ 62,074 (2013).

The FERC approved Texas Eastern Transmission, LP's (Texas Eastern) request to abandon "numerous natural gas facilities which are no longer in service and for which Texas Eastern has been unable to locate documentation identifying the facilities' regulatory status."[37] Due to "extensive system history, various ownership changes, the loss of records following flooding as a result of Tropical Storm Allison in 2001, and its records retention policy, Texas Eastern [had] been unsuccessful in determining the regulatory status of the facilities that are the subject of Texas Eastern's abandonment application."[38] The FERC approved the proposal because it constituted a procedural clarification which would not affect operating conditions, design capacity, or the environment.[39]

8. *Transcontinental Gas Pipe Line Co.*, 144 FERC ¶ 61,042, *reh'g denied*, 145 FERC ¶ 61,251 (2013).

The FERC granted, subject to conditions, Transcontinental Gas Pipe Line Company, LLC's (Transco) application to replace certain pipeline segments and abandon pressure control facilities in connection with its Brandywine Creek Replacement Project (Brandywine Project).[40] The FERC also granted "a presumption favoring rolling the costs of the [Brandywine Project] into the incremental rates for service on the Sentinel Expansion Project" in Transco's next rate proceeding.[41] With respect to the Brandywine Project, the FERC found it had independent utility because it was intended to bring the facilities that Transco constructed as part of the Sentinel Expansion Project into compliance with federal pipeline safety regulations.[42] However, the FERC denied rehearing and found that the costs of the Brandywine Project could not be rolled into Transco's existing mainline rates, reasoning that if Transco had constructed the Sentinel Expansion Project as authorized, the Brandywine Project would have been unnecessary.[43] Therefore, the Brandywine Project entailed additional costs related to the Sentinel Expansion Project, and responsibility for those additional costs had to be assigned to Transco and its Sentinel Expansion customers.[44]

36. *Id.* at P 19.
37. *Tex. E. Transmission, LP*, 145 F.E.R.C. ¶ 62,074, 64,156 (2013).
38. *Id.*
39. *Id.* ¶ 64,157.
40. *Transcon. Gas Pipe Line Co.*, 144 F.E.R.C. ¶ 61,042 at P 1, *reh'g denied*, 145 F.E.R.C. ¶ 61,251 (2013).
41. 144 F.E.R.C. ¶ 61,042 at P 20.
42. *Id.* at P 24.
43. 145 F.E.R.C. ¶ 61,251 at P 9.
44. *Id.* at P 10.

9. *Transcontinental Gas Pipe Line Co.*, 147 F.E.R.C. ¶ 61,091 (2014).

The FERC granted rehearing of its prior order approving Transco's application to abandon four of the seven natural gas storage caverns at its Eminence Storage Field in Mississippi.[45] The FERC dismissed as moot the requests of several state agencies for clarification or rehearing.[46] On rehearing, the FERC (a) accepted Transco's statement of Cavern 7's capacity;[47] (b) accepted Transco's explanation regarding the injection rate of Cavern 7;[48] (c) allowed Transco to continue to use its annual inventory verification program through a central metering facility until June 2014;[49] and (d) agreed to a five-year duration for the period during which Transco would be required to monitor groundwater methane levels.[50] The FERC rejected as moot rehearing requests by state agencies related to cost recovery due to their participation in settlement negotiations in Transco's concurrent NGA section 4 rate proceeding in Docket No. RP12-993-000.[51]

B. Acquisition Premium

1. *Missouri Interstate Pipeline, LLC*, 144 F.E.R.C. ¶ 61,220 (2013).

The FERC denied rehearing of its March 21, 2013 Order (the March Order)[52] permitting MoGas Pipeline LLC (MoGas) to include an acquisition premium in its initial rate base (Rehearing Order).[53] The Rehearing Order affirmed the March Order's prior reversal in part and affirmation in part of the rulings of an administrative law judge's initial decision.[54] The March Order had permitted MoGas to include in its initial rate base the full purchase price that its predecessor had paid in 2001 to acquire 5.6 miles of former oil pipelines.[55] The Rehearing Order explained that because the 2001 purchase price of the former oil pipeline facilities had been lower than the cost of constructing comparable facilities, MoGas's ratepayers benefitted from recourse rates that would "be no higher, if not lower, than if the pipeline built new facilities,"[56] and that substantial evidence supported a finding that the acquisition premium was attributable to the former oil pipeline facilities.[57]

45. *Transcon. Gas Pipe Line Co.*, 147 F.E.R.C. ¶ 61,091 at PP 1-2 (2014).
46. *Id.* at P 2.
47. *Id.* at PP 16-17.
48. *Id.* at P 20.
49. *Id.* at PP 22, 24.
50. 147 F.E.R.C. ¶ 61,091 at P 35.
51. *Id.* at P 38.
52. *Mo. Interstate Gas, LLC*, 142 F.E.R.C. ¶ 61,195, *reh'g denied*, 144 F.E.R.C. ¶ 61,220 (2013).
53. 144 F.E.R.C. ¶ 61,220.
54. *Mo. Interstate Gas, LLC*, 137 F.E.R.C. ¶ 63,014 at PP 1-3 (2011).
55. *Id.* at PP 56, 58.
56. 144 F.E.R.C. ¶ 61,220 at P 58.
57. *Id.* at P 29.

C. Capacity Allocation

1. *Columbia Gas Transmission, LLC*, 147 F.E.R.C. ¶ 61,260 (2014) and *Columbia Gulf Transmission, LLC*, 147 F.E.R.C. ¶ 61,259 (2014).

The FERC approved requests by Columbia and Columbia Gulf to revise their respective Parking and Lending (PAL) rate schedules to allocate capacity on the basis of net present value, rather than based on nominated quantities.[58] In response to comments by a shipper, Columbia and Columbia Gulf agreed to modify their PAL rate schedules to clarify that charges for both PAL and AutoPAL services would be reduced on any day in which a shipper is unable to reduce its PAL or AutoPAL balances due to scheduling constraints.[59]

2. *Transcontinental Gas Pipe Line Co., LLC*, 147 F.E.R.C ¶ 61,033 (2014).

The FERC accepted a compliance filing submitted by Transco regarding a proposal to revise its firm rate schedules to clarify the allocation of capacity at points of receipt within the shipper's firm contract path, as well as "traditional" and "non-traditional" delivery points.[60] In its compliance filing, Transco explained that the revisions to its firm rate schedule would more accurately reflect "long-standing circumstances on its system" that "continue the receipt point access rights for firm shippers that existed on the Transco system prior to the restructuring of natural gas pipelines in Order No. 636," under which shippers were not guaranteed receipt point capacity at any specific point.[61] The FERC found that Transco's proposed scheduling revisions were consistent with its historic practices and the intent of long-standing settlement agreements and thus could not be modified absent a finding under section 5 of the NGA, regardless of whether such practices were different from those found on other pipelines.[62]

D. Capacity Release

1. Orders Waiving Capacity Release Rules

In various letter orders, the FERC granted over two dozen waivers of capacity release rules in the period from July 2013 to June 2014.[63] The FERC granted such

58. *Columbia Gas Transmission, LLC*, 147 F.E.R.C. ¶ 61,260 (2014).

59. *Columbia Gulf Transmission, LLC*, 147 F.E.R.C. ¶ 61,259 (2014).

60. *Transcon. Gas Pipe Line Co.*, 147 F.E.R.C ¶ 61,033 at P 2 (2014).

61. *Id.* at P 17.

62. *Id.* at P 25.

63. *ProLiance Energy, LLC*, 144 F.E.R.C. ¶ 61,037 at P 1 (2013); *ProLiance Energy, LLC*, 144 F.E.R.C. ¶ 61,075 (2013); *ProLiance Energy, LLC*, 144 F.E.R.C. ¶ 61,154 (2013); *ProLiance Energy, LLC*, 144 F.E.R.C. ¶ 61,155 (2013); *Apache Corp. Fieldwood Energy*, 144 F.E.R.C. ¶ 61,201 (2013); *Direct Energy Bus., LLC*, 144 F.E.R.C. ¶ 61,231 (2013); *Petrohawk Energy Corp.*, 144 F.E.R.C. ¶ 61,234 (2013); *Cheyenne Plains Gas Pipeline Co.*, 145 F.E.R.C. ¶ 61,006 (2013); *Va. Power Energy Mktg., Inc.*, 145 F.E.R.C. ¶ 61,066 (2013); *El Paso Mktg. Co.*, 145 F.E.R.C. ¶ 61,075 (2013); *Laclede Gas Co.*, 145 F.E.R.C. ¶ 61,067 (2013); *Ameren Energy Generating Co.*, 145 F.E.R.C. ¶ 61,148 (2013); *S. Union Co.*, 145 F.E.R.C. ¶ 61,165 (2013); *Rochester Gas & Elec. Corp.*, 145 F.E.R.C. ¶ 61,164 (2013); *PDC Energy, Inc.*, 145 F.E.R.C. ¶ 61,177 (2013); *AEP Generation Res. Inc.*, 145 F.E.R.C. ¶ 61,211 (2013); *EnerVest Energy Institutional Fund XIII-A, L.P.*, 146 F.E.R.C. ¶ 61,021 (2014); *Wyo. Interstate Co.*, 146 F.E.R.C. ¶ 61,040 (2013); *Rocky Mountain Natural Gas LLC*, 146 F.E.R.C. ¶

waivers primarily to facilitate asset sales, corporate reorganizations, and similar transactions. Waivers were generally limited in term to 90 to 180 days following the order or the closing of the pertinent transaction. The capacity release rules commonly waived included the prohibition on buy-sell arrangements, the prohibition on tying, posting and bidding requirements, the prohibition on the release of capacity at a rate above the maximum recourse rate, and the shipper-must-have-title policy.[64] Capacity release rule violations were not the subject of a substantial number of self-reports or other enforcement activity during fiscal year 2013.[65]

2. Posting of Offers to Purchase Capacity, 146 F.E.R.C. ¶ 61,203 (2014).

The FERC issued a show-cause order pursuant to section 5 of the NGA[66] to require all interstate pipelines to demonstrate compliance with section 284.8(d) of the FERC's regulations.[67] That section of the regulations was adopted pursuant to FERC Order 637-A, to require that pipelines post notices of offers to purchase released capacity.[68] Current rules require that pipelines "provide notice of offers to release or purchase capacity [and] the terms and conditions of such offers . . . on an Internet website, for a reasonable period."[69] The FERC reviewed a sampling of interstate pipelines' informational posting websites and found that none provided information about how and where offers to purchase released capacity could be posted.[70] Consequently, the FERC ordered that all interstate pipelines submit filings within sixty days of the order that either revise their tariffs to provide for posting of offers to buy released capacity or otherwise show compliance with section 284.8(d).[71] In response, pipeline companies submitted revised tariffs to demonstrate compliance. Some companies also filed motions to intervene, and a handful of companies filed comments primarily to voice support for the FERC's order or to clarify the length of time that offers must be posted to qualify as being posted "for a reasonable period."[72]

61,045 (2014); *ONEOK, Inc.*, 146 F.E.R.C. ¶ 61,047 (2014); *Tallgrass Interstate Gas Transmission, LLC*, 146 F.E.R.C. ¶ 61,048 (2014); *Gavilon, LLC*, 146 F.E.R.C. ¶ 61,219 (2014); *Noble Energy, Inc.*, 146 F.E.R.C. ¶ 61,227 (2014); *Eni Petroleum US LLC*, 147 F.E.R.C. ¶ 61,007 (2014); *Wyo. Interstate Co., L.L.C.*, 147 F.E.R.C. ¶ 61,062 (2014); *Rockies Express Pipeline LLC*, 147 F.E.R.C. ¶ 61,063 (2014); *GeoMet, Inc.*, 147 F.E.R.C. ¶ 61,083 (2014).

64. *See, e.g.*, *ProLiance Energy, LLC*, 144 F.E.R.C. ¶ 61,037 at PP 3-4 (2013).

65. OFFICE OF ENFORCEMENT, FED. ENERGY REGULATORY COMM'N, 2013 REPORT ON ENFORCEMENT, DOCKET NO. AD07-13-006 14-15 (2013), *available at* http://www.ferc.gov/legal/staff-reports/2013/11-21-13-enforcement.pdf.

66. 15 U.S.C. § 717d(a) (2012).

67. Order to Show Cause, *Posting of Offers to Purchase Capacity*, 146 F.E.R.C. ¶ 61,203 at P 6 (2014) [hereinafter *Posting of Offers to Purchase Capacity*].

68. Release of Firm Capacity on Interstate Pipelines, 18 C.F.R. § 284.8(d) (2013).

69. *Id.*

70. *Posting of Offers to Purchase Capacity*, *supra* note 67 at PP 4-5.

71. *Id.* at P 6.

72. *Id.* at P 5. *See, e.g.*, Motion to Intervene and Comments of Piedmont Natural Gas Company, Inc., Docket No. RP14-442-000 (Mar. 31, 2014) (moving to intervene in support of the Order to Show Cause); Motion to Intervene and Comment of Arkansas Electric Cooperative Corporation, Docket No. RP14-960-000 (June 2, 2014) (seeking clarification on the length of time that offers must be posted).

E. Cost Trackers

1. *Rockies Express Pipeline LLC*, 147 F.E.R.C. ¶ 61,248 (2014).

The FERC accepted a May 16, 2014 settlement filed by Rockies Express Pipeline LLC (REX) to resolve three proceedings concerning REX's tariff tracker mechanism for collecting (1) fuel and lost and unaccounted-for (FL&U) quantities, and (2) electric powered compression costs.[73] In an Initial Decision dated June 28, 2013,[74] the FERC determined, *inter alia*, that REX's tracker proposal was contrary to both REX's tariff and Commission policy.[75] The FERC found that pipelines were to retain operational sales proceeds under cost trackers only when (1) the sales are incidental to operations, (2) the sales are unbundled from transportation functions, and (3) any revenue is reported to the FERC.[76]

The May 16, 2014 settlement was uncontested, but one party filed comments requesting that the FERC condition approval of the tariff revisions on the ANR Policy and the FERC's decision in *Ruby Pipeline*.[77] The FERC declined to impose the additional conditions, finding that no party, including the commenter, alleged that the implementing tariffs deviated from the parties' intentions, and that the commenter had participated in the negotiations.[78] The settlement required settlement payments by REX of $22.8 million related to the index price issues, and $11.7 million to cash-out the over-recovery amounts;[79] submission of *pro forma* tariff records to establish a separate tracker for REX's electric compression power costs, and establishment of separate deferred accounts to track the monthly quantity of under- and/or over-recovered fuel and lost and unaccounted for gas, and of under- and/or over-recovered electric power costs for each zone.

2. *Millennium Pipeline Co., LLC*, 146 F.E.R.C. ¶ 61,156 (2014).

The FERC accepted Millennium's proposal to recover electric costs attributable to electric heaters operated with gas fired compressors by converting the electric costs to dekatherms (dth) based on a spot price, and including the associated dth quantity in its effective in-kind gas retainage mechanism.[80] The FERC acknowledged concerns that conversion of monetary electric costs to dth for in-kind recovery in a fuel tracker can result in (1) over-recovery due to price fluctuations in electric costs and natural gas prices and (2) lack of transparency.[81] However, the FERC distinguished *Millennium* from *Rockies Express Pipeline* based on findings that the electric heater costs involved were "very small

73. *Rockies Express Pipeline LLC*, 147 F.E.R.C. ¶ 61,248 at P 1 (2014).

74. *Rockies Express Pipeline LLC*, 143 F.E.R.C. ¶ 63,017, *corrected*, 144 F.E.R.C. ¶ 63,002 (2013).

75. 143 F.E.R.C. ¶ 63,017 at P 55; *El Paso Natural Gas Co.*, 129 F.E.R.C. ¶61,006 at P 19 (2009) (citing *Colo. Interstate Gas Co.*, 128 F.E.R.C. ¶61,117 at P 34 (2009)).

76. 143 F.E.R.C. ¶ 63,017 at P 102.

77. 147 F.E.R.C. ¶ 61,248 at P 9.

78. *Id.* at P 10.

79. Offer of Settlement and Stipulation Agreement, *Rockies Express Pipeline LLC*, Art. 3, Docket Nos. RP11-1184 et al. (filed May 16, 2014).

80. *Millennium Pipeline Co.*, 146 F.E.R.C. ¶ 61,156 at P 4 (2014).

81. *Id.* at PP 12, 22.

compared to total fuel costs," and accordingly should not cause any significant volatility or lack of transparency,[82] and separate recovery of electric costs would impose a significant administrative burden on both Millennium and its shippers.[83]

3. *ANR Pipeline Co.*, 147 F.E.R.C. ¶ 61,124 (2014).

The FERC reconsidered an April 29, 2013 suspension order on a Deferred Transportation Cost Adjustment (DTCA) filing by ANR Pipeline Company (ANR) seeking recovery of third-party pipeline transportation costs under FERC Account No. 858.[84] The specific issue presented was whether the costs attributable to a new Part 284 firm agreement with Great Lakes Gas Transmission Limited Partnership (Great Lakes) were eligible for recovery through the DTCA.[85] In the April 2013 Order, the FERC rejected ANR's contention that the Great Lakes agreement was a "replacement contract."[86] However, in the May 2014 rehearing order, the FERC found that there was sufficient ambiguity as to the term "contract replacement" and the circumstances surrounding the contract replacement, to set those issues for hearing before an Administrative Law Judge.[87] The FERC emphasized, however, "the Commission's long-standing policy to narrowly construe cost trackers,"[88] and that the decision to set the issue for hearing "does not relieve ANR of the burden of demonstrating that any costs it seeks to flow though to its customers in this manner . . . are reasonable and were prudently incurred."[89]

4. *Dauphin Island Gathering Partners*, 146 F.E.R.C. ¶ 61,246, *further order*, 147 F.E.R.C. ¶ 61,250 (2014).

The FERC found that certain costs Dauphin Island had included in calculating the Storm Surcharge did not satisfy the definition of "Eligible Costs" as set forth in its tariff, and accordingly directed Dauphin Island to correct its Storm Surcharge Deferred Cost Account.[90] The FERC stated that in general, a "Storm Surcharge is a variable cost tracker that allows a pipeline to manage the costs associated with natural disasters."[91] The FERC rejected Dauphin Island's proposal to recover costs related to "bracing modifications" to offshore platforms "mandated by the Department of the Interior's Bureau of Safety and Environmental Enforcement (BSEE) to comply with BSEE standards for hurricane conditions."[92] The FERC found that the language of Dauphin Island's tariff permitted Storm Surcharge recovery of cost "to repair damage and/or

82. *Id.*; 146 F.E.R.C. ¶ 61,156 at P 22.
83. 146 F.E.R.C. ¶ 61,156 at P 22.
84. *ANR Pipeline Co.*, 147 F.E.R.C. ¶ 61,124 at PP 2-3 (2014).
85. *Id.* at PP 5-6.
86. *Id.* at P 27.
87. *Id.*
88. 147 F.E.R.C. ¶ 61,124 at P 27.
89. *Id.* at P 28 (quoting *ANR Pipeline Co.*, 69 F.E.R.C. ¶ 61,322, 62,226 (1994)).
90. *Dauphin Island Gathering Partners*, 147 F.E.R.C. ¶ 61,250 at P 1 (2014).
91. *Id.* at P 2.
92. *Id.* at PP 3, 9.

recover system operations related to a Storm," but the bracing modifications were intended to "render Dauphin Island's facilities better able to withstand damage from future storms," not for repair or recovery.[93]

F. Discount Adjustments for Negotiated Rate Agreements

1. *Gulf Crossing Pipeline Co.*, 144 F.E.R.C. ¶ 61,196 (2013).

Gulf Crossing Pipeline Company LLC (Gulf Crossing) sought a predetermination that it would be permitted to roll the costs associated with proposed new pipeline facilities into its general system rates in its next NGA section 4 general rate proceeding.[94] Gulf Crossing had entered into a negotiated rate agreement with a shipper for service on the project facilities.[95] Noting that Gulf Crossing's tariff included a provision permitting it to "seek discount-type adjustments for negotiated rates" in NGA section 4 proceedings,[96] the FERC stated that in evaluating Gulf Crossing's request for a roll-in predetermination, it would "compare project costs to the revenues that will be generated from the contracted volumes at the negotiated rates, which are lower than Gulf Crossing's maximum recourse rates."[97] Based on that comparison, the FERC determined that the project's annual revenue would be less than its annual cost of service in each of the first three years of operation, and denied the roll-in predetermination request.[98]

G. Fuel

1. *Texas Eastern Transmission LP*, 144 F.E.R.C. ¶ 61,039 (2013).

Historically, gas flowed from south to north on all portions of Texas Eastern's system.[99] Texas Eastern argued that the development of new sources of supply in Texas Eastern's Market Area, particularly in the Marcellus Shale, led to customer-nominated flows counter to the historical patterns in the Access Area.[100] Accordingly, Texas Eastern said it was no longer feasible to make case-by-case determinations of actual flows to determine which transactions should be subject to a fuel charge, and proposed to assess a fuel charge on all transactions in the Access Area.[101]

The FERC found that Texas Eastern "demonstrated that it is experiencing bi-directional flows in its Access Area to the extent that it is no longer feasible for it to ascertain whether certain individual transactions consist solely of backhaul transportation, which would thus qualify for [a fuel charge] of zero under its

93. *Id.* at P 9.
94. *Gulf Crossing Pipeline Co.*, 144 F.E.R.C. ¶ 61,196 at P 3 (2013).
95. *Id*. at P 4.
96. *Id*. at P 15.
97. *Id*.
98. *Id*. at P 16.
99. *Tex. E. Transmission LP*, 144 F.E.R.C. ¶ 61,039 at P 2 (2013).
100. *Id.* at P 4.
101. *Id.*

tariff."[102] The FERC restated its policy that "all transportation service transactions would be assessed a fuel charge unless the pipeline can demonstrate that a particular transaction *does not* consume fuel. Because the presumption is that all transactions consume fuel, pipelines *are not required* to demonstrate that specific transactions consume fuel."[103]

2. *Washington Gas Light Co.*, 145 F.E.R.C. ¶ 61,092 (2013).

During Washington Gas Light's (WGL) investigation of a significant increase in its fuel, the lost and unaccounted-for gas (LAUF) percentage led it to conclude that it had delivered 914,954 dth more of natural gas to its transportation customer, Mountaineer Gas Company (Mountaineer), than its meter had measured.[104] WGL proposed to recover this amount through a LAUF applicable only to Mountaineer.[105] WGL argued that the gas fell within the definition of LAUF and that it was appropriate to recover it solely from Mountaineer because Mountaineer was the only customer that benefited from the unaccounted-for gas.[106] The FERC rejected WGL's proposal and held that "gas delivered to a customer is neither lost nor unaccounted for. Therefore, such gas may not be recovered pursuant to the LAUF provisions of a pipeline's tariff."[107] The FERC noted the possibility that WGL may be entitled to recover the cost of that gas from the shipper through its tariff's imbalance provisions, but made no definitive findings on that subject.[108]

3. *Southern Star Central Gas Pipeline Inc.*, 146 F.E.R.C. ¶ 61,242 (2014).

The FERC held in its letter order ruling that 81,177 dth of natural gas, lost during six incidents reported to the U.S. Department of Transportation (under 49 C.F.R. section 191.3), was not appropriate for inclusion in the pipeline's fuel tracker.[109] Fuel tracking mechanisms, the FERC said,

> [a]re appropriate for normal operating costs but are not appropriate for the recovery of gas losses outside the scope of normal pipeline operations. The losses reported to Department of Transportation included losses due to line failures, line blow downs due to a leak, and losses due to leaking coupling, items that are not typically recurring events, but reflect an abnormal pipeline malfunction.[110]

4. *High Point Gas Transmission LLC*, 144 F.E.R.C. ¶ 61,250 (2013); *ETC Tiger Pipeline LLC*, 145 F.E.R.C. ¶ 61,171 (2013); *Midcontinent Express Pipeline LLC*, 145 F.E.R.C. ¶ 61,174 (2013); *High Island Offshore System L.L.C.*, 147 F.E.R.C. ¶ 61,149 (2014); *Fayetteville Express Pipeline LLC*, 147 F.E.R.C. ¶ 61,160 (2014); and *ETC Tiger Pipeline LLC*, 147 F.E.R.C. ¶

102. *Id.* at P 36.
103. *Id.* at P 44.
104. *Wash. Gas Light Co.*, 145 F.E.R.C. ¶ 61,092 at PP 8-9 (2013).
105. *Id.* at PP 9-10.
106. *Id.*
107. *Id.* at P 26.
108. *Id.* at PP 35-36.
109. *S. Star Cent. Gas Pipeline Inc.*, 146 F.E.R.C. ¶ 61,242 at P 10 (2014).
110. *Id.* at P 9.

61,166 (2014).

In the six cases above, the FERC granted waivers to pipelines permitting them to set fuel or lost and unaccounted for gas reimbursement percentages at zero when the respective tariffs would have otherwise required a negative percentage.[111] The FERC stated that keeping the reimbursement rates at zero, rather than allowing the overall reimbursement rates to go negative is "reasonable so long as all of the over-recovered amount is eventually returned to the shippers."[112]

H. Gas-Electric Coordination

1. Communication of Operational Information between Natural Gas Pipelines and Electric Transmission Operators, 144 F.E.R.C. ¶ 61,043 (2013) and 145 F.E.R.C. ¶ 61,134 (2013).

On July 18, 2013, the FERC issued a Notice of Proposed Rulemaking (NOPR) proposing to revise parts 38 and 284 of the FERC's regulations with respect to communications between the gas and electric industries.[113] On November 15, 2013, the FERC issued a Final Order adopting the NOPR as proposed, with no modifications.[114] The new rule provides

> explicit authority to interstate natural gas pipelines and public utilities that own, operate, or control facilities used for the transmission of electric energy in interstate commerce to share non-public, operational information with each other for the purpose of promoting reliable service or operational planning on either the public utility's and pipeline's system.[115]

The new regulations include a "No-Conduit Rule" that prohibits "all public utilities and . . . pipelines, as well as their employees, contractors, consultants, or agents, from disclosing, or using anyone as a conduit for the disclosure of, non-public, operational information" received under the rule to a third party.[116] The rules similarly prohibit the disclosure of such non-public, operational information to the transmission operator's marketing function employees, as that term is defined in section 358.3 of the FERC's regulations.[117] The No-Conduit Rule also applies to any employees an interstate pipeline shares with gathering or intrastate pipeline affiliates.[118] Non-public, operational information is defined as "information that is not publicly posted, yet helps transmission operators to

111. *High Point Gas Transmission LLC*, 144 F.E.R.C. ¶ 61,250 (2013); *ETC Tiger Pipeline LLC*, 145 F.E.R.C. ¶ 61,171 (2013); *Midcontinent Express Pipeline LLC*, 145 F.E.R.C. ¶ 61,174 (2013); *High Island Offshore Sys. LLC*, 147 F.E.R.C. ¶ 61,149 (2014); *Fayetteville Express Pipeline LLC*, 147 F.E.R.C. ¶ 61,160 (2014); *ETC Tiger Pipeline LLC*, 147 F.E.R.C. ¶ 61,166 (2014).

112. *See, e.g.*, *ETC Tiger Pipeline LLC*, 145 F.E.R.C. ¶ 61,171 at P 8 (2013) (citing *Columbia Gulf Transmission Co.*, 132 F.E.R.C. ¶ 61,134 at P 43 (2010)).

113. Notice of Proposed Rulemaking, *Communication of Operational Information between Natural Gas Pipelines and Electric Transmission Operators*, 144 F.E.R.C. ¶ 61,043 (2013).

114. Order No. 787, *Communication of Operational Information between Natural Gas Pipelines and Electric Transmission Operators*, 145 F.E.R.C. ¶ 61,134 (2013).

115. *Id.* at P 1.

116. *Id.* at P 60.

117. *Id*. at PP 15-17; 18 C.F.R. § 358.3(d) (2013).

118. *See, e.g.*, 145 F.E.R.C. ¶ 61,134 at P 97.

operate and maintain either a reliable pipeline system or a reliable electric transmission system on a day-to-day basis, as well as during emergency conditions or for operational planning."[119] This includes "information dealing with actual, anticipated, or potential effects on the ability to provide electric and gas service based on the respective operator's experience and understanding of the operational capability and customer demands on their respective systems."[120] The rule does not provide an exhaustive list of what is considered non-public operational information.[121] However, it states that the determination will be within the transmission operators' discretion, because they have the "most insight and knowledge of their systems."[122] By not limiting the definition of non-public operational information, the rule provides flexibility to the operators as well as improved cohesion between the industries.[123] Additionally, the rule includes a compliance help-line where inquiries on a case-by-case basis can be made.[124]

In Order No. 787-A, the FERC denied rehearing of Order No. 787. The FERC rejected a request to revise the No-Conduit Rule to allow disclosures to third parties (other than marketing function employees), finding that concerns regarding shared operating employees would be better addressed through waiver requests than a general exception to the No-Conduit Rule.[125] The FERC also denied a request to establish a future technical conference to assess the effectiveness of Order No. 787, finding no need to commit to a technical conference or other specific process for evaluating Order No. 787.[126]

I. Gas Quality and Interchangeability

1. *Trailblazer Pipeline Co.*, 144 F.E.R.C. ¶ 61,084; 145 F.E.R.C. ¶ 61,299 (2013).

The FERC rejected Trailblazer Pipeline Company LLC's (Trailblazer) proposed changes to its gas quality tariff specifications because the pipeline failed to meet the FERC's gas quality policies.[127] Specifically, the FERC rejected new limitations on inert substances, hydrogen sulfide, and sulfur because Trailblazer had not provided any data indicating the additional limits were necessary to protect the system. The FERC accepted Trailblazer's proposed gas quality waiver provision as consistent with the Gas Quality Policy Statement, and the proposed gas quality damages provision and commingling provision as consistent with FERC policy.[128]

119. *Id.* at P 33.
120. *Id.*
121. *Id.* at P 41.
122. *Id.* at P 34.
123. *Id.* at P 42.
124. *Id.*
125. Order No. 787-A, *Communication of Operational Information between Natural Gas Pipelines and Transmission Operators*, 147 F.E.R.C. ¶ 61,228 at PP 11-18 (2014).
126. *Id*. at P 21.
127. *Trailblazer Pipeline Co.*, 145 F.E.R.C. ¶ 61,299 at P 16 (2013).
128. *Id.* at PP 46, 49.

2. *Texas Eastern Transmission, LP*, 144 F.E.R.C. ¶ 61,082; 145 F.E.R.C. ¶ 61,277 (2013).

On December 26, 2013, the FERC approved an unopposed settlement modifying the provisions of Texas Eastern's gas quality tariff providing for a Control Zone on its system from Berne, Ohio to Uniontown, Pennsylvania within which it will accept, subject to its ability to blend with other supplies at the Uniontown Control Point, Marcellus and Utica shale natural gas with levels of ethane (C2+) exceeding 12%. The settlement also permits Texas Eastern to issue Action Alerts to request the voluntary delivery of additional low C2+ gas into the Control Zone if it anticipates that C2+ will exceed 12% at Berne on any gas day.[129]

J. Jurisdiction

1. *BP America Inc., BP Corp. North America Inc., BP America Production Co., BP Energy Co.*, 147 FERC ¶ 61,130 (2014).

In BP America, among other things, the Commission established a hearing to determine whether BP Corporation North America Inc., BP America Production Company, and BP Energy Company (collectively, BP) violated section 4A of the NGA and the Commission's Anti-Manipulation Rule, codified in 18 C.F.R. section 1c.1.[130] Also, the Commission denied BP's motion to dismiss the Commission order to show cause why it should not find that "BP manipulated the next day, fixed-price natural gas market at the Houston Ship Channel from September through November 30, 2008."[131] On June 13, 2014, BP filed a request for hearing. The Commission's decision on the rehearing request is pending.

The conduct at issue, transporting and trading of gas at the Houston Ship Channel, affected the Houston Ship Channel Gas Daily index, which sets the price for Commission-Jurisdictional transactions, and consequently, subjects BP's conduct to the Commission's jurisdiction. Specifically, section 4A of the NGA and the Anti-Manipulation rule give the Commission jurisdiction "over conduct that directly affects jurisdictional transactions," whether or not the conduct is expressly covered by section 1(b) of the NGA.[132] Section 4A applies to any entity that directly or indirectly uses or employs manipulative tactics, "in connection with" jurisdictional transactions.[133] The phase "in connection with" is further defined in Order No. 670, promulgated pursuant to the Energy Policy Act of 2005 (EPAct), as "encompassing situations in which there is a nexus between the fraudulent conduct of an entity and a jurisdictional transaction."[134]

Also, in *Barclays*, the Commission explained that, under the anti-manipulation provisions of the Federal Power Act (FPA) and related regulations,

129. *Tex. E. Transmission, LP*, 145 F.E.R.C. ¶ 61,277 at PP 1, 6-7 (2013).

130. *BP America Inc.*, *et al.*, 147 F.E.R.C. ¶ 61,130 at P 1.

131. *Id.* at P 2.

132. *Id.* at P 21.

133. *Id.* at P 26.

134. *Id.* at P 23 (citing Order No. 670, FERC STATS. & REGS. ¶ 31,202 at P 22 (codified at 18 C.F.R. §§ 1c.1, 1c.2)).

the type of conduct "in connection with" a jurisdictional transaction is conduct that the entity must have intended to affect, or have acted recklessly to affect, a jurisdictional transaction.[135] Identical provisions in the FPA and NGA are interpreted identically, so while BP engaged in a non-jurisdictional intrastate transaction, because it had the requisite intent to affect the daily price at the Houston Ship Channel, which sets the price for both non-jurisdictional and jurisdictional transactions, its conduct was in connection with a jurisdictional transaction, and therefore, under the Commission's jurisdiction.

In addition, under *Conoco Inc. v. FERC*, the court held that the Commission may exercise "stand-by" jurisdiction over non-jurisdictional activities that are "intertwined" with, and subsequently, affect jurisdictional activities.[136] Because BP's alleged conduct affected an index used to set prices for jurisdictional transactions, the Commission may exercise its "stand-by" jurisdiction.

Finally, the D.C. Circuit decision in *Hunter*[137] does not foreclose the Commission's "in connection with" jurisdiction.[138] Unlike *Hunter*, where the court held that the Commodity Futures Trading Commission (CFTC) has exclusive jurisdiction over the futures market, here, the states do not have exclusive jurisdiction of the gas transactions at issue.[139] Thus, the Commission is not precluded from exercising its jurisdiction to prohibit natural gas market manipulation, even if the state is regulating the same conduct. And, if the state's regulation conflicted with Commission's jurisdiction, the Commission would prevail as the United States Supreme Court has consistently held that states may not directly regulate the price of Commission-jurisdictional transactions.[140] Moreover, in *Hunter*, the court did not decide on whether the Commission's Anti-Manipulation Rule applies to non-jurisdictional transactions. Rather, it held that the Commission's "in connection with" jurisdiction allows it to freely prohibit manipulative trading in markets outside the CFTC's exclusive jurisdiction.[141]

2. *Sierrita Gas Pipeline, LLC,* 147 FERC ¶ 61,192 (2014).

In this order, the Commission issued the following certificates to allow Sierrita Gas Pipeline, LLC (Sierrita) to construct and operate a new 60.9-mile interstate natural gas pipeline in Arizona.[142] The Commission approved Sierrita's Environmental Impact Assessment (EIS), but held that certain protests address issues that are not under the Commission's jurisdiction.[143] Specifically, issues concerning the restoration efforts of the Kinder Morgan petroleum pipelines are not in the Commission's jurisdiction; however, the Commission will still require

135. 147 F.E.R.C. ¶ 61,130 at P 23 (citing *Barclays Bank PLC,* 144 F.E.R.C. ¶ 61,041 at P 113 (2013) (*Barclays*)).

136. 147 F.E.R.C. ¶ 61,130 at P 25 (citing Conoco Inc. v. FERC, 90 F.3d 536 (D.C. Cir. 1996)).

137. Hunter v. FERC, 711 F.3d 155, 155 (D.C. Cir. 2013).

138. 147 F.E.R.C. ¶ 61,130 at P 29.

139. *Id.*

140. *Id.* at P 29.

141. *Id.* at P 31.

142. *Sierrita Gas Pipeline, LLC,* 147 F.E.R.C. ¶ 61,192 at P 1 (2014).

143. *Id.* at PP 61, 172.

Sierrita to implement the restoration measures identified in the EIS.[144] Similarly, payments Sierrita will make to Pima County, which will be impacted by the new pipeline, for permits and taxes, are not under the Commission's jurisdiction.[145] In addition, issues regarding the thickness of the pipeline wall are under the jurisdiction of the U.S. Department of Transportation, not the Commission.[146]

K. Market-Based Rates

The FERC granted Arlington Storage Company, LLC (Arlington) a certificate of authorization and reaffirmed its market-based rate authority in the expansion of the Seneca Lake Storage Project (Seneca Lake Project), subject to conditions laid out by the FERC.[147] The FERC concluded that the Seneca Lake Project expansion would not allow Arlington to exercise market power in the relevant market, and since the application was unopposed, its authority was approved.[148] The FERC noted that its approval of market-based rates is subject to re-examination in the event Arlington or an affiliate adds storage capacity, an affiliate links storage facilities to the project, or Arlington or an affiliate acquires an interest in, or is acquired by, an interstate pipeline connected to the project.[149]

L. New Services

1. *Equitrans, L.P.*, 147 F.E.R.C. ¶ 61,074 (2014).

The FERC accepted a proposal by Equitrans, L.P. (Equitrans) to implement a new interruptible wheeling service under Rate Schedule IWS.[150] Under Rate Schedule IWS, shippers would have the ability to transfer gas on an interruptible basis between two delivery point interconnections on Equitrans' system. The FERC held that Equitrans had failed to fully address concerns that Rate Schedule IWS could result in physical transportation and expressed concern that

> Equitrans' proposal to base its Rate Schedule IWS service on the use of displacement without the use of fuel as described in its Transmittal letter depends on its evaluation of unspecified operating conditions, and future shipper proposals, and Equitrans reserves the right to engage in some unspecified IWS transactions which will use fuel.[151]

The FERC directed Equitrans to "fully explain its proposed service and provide tariff records that purport to implement the service as explained",[152] as well as to clarify whether the PSC would be imposed on Rate Schedule IWS. The FERC further rejected Equitrans' request for a waiver of the requirement to provide a projection of the costs and revenues of Rate Schedule IWS because the

144. *Id.* at P 172 (2014).
145. *Id.* at P 168.
146. *Id. at* P 164.
147. *Arlington Storage Co., LLC*, 147 F.E.R.C. ¶ 61,120 at PP 1, 2 (2014).
148. *Id.* at P 38.
149. *Id.* at P 39.
150. *Equitrans, L.P.*, 147 F.E.R.C. ¶ 61,074 at P 1 (2014).
151. *Id.* at P 15 (2014).
152. *Id.* at P 20.

FERC could not "determine the extent or nature of the service Equitrans proposes."[153]

M. Open Seasons

1. *Encana Mktg. (USA) Inc. v. Rockies Express Pipeline LLC*, 146 F.E.R.C. ¶ 61,161 (Mar. 7, 2014).

Encana Marketing Inc. (Encana) filed a complaint against Rockies Express Pipeline LLC (REX) for unlawfully denying its request to reallocate the primary delivery point capacity defined under its contract with REX.[154] The FERC held that REX had the ability to deny the service request because it was to commence 187 days in the future, while FERC policy requires delivery point changes to be effective within ninety days.[155] The FERC also held that under FERC policy and REX's tariff, REX has discretion to sell capacity on a first-come, first-served basis, without conducting an open season, as long as the pipeline posts all available capacity.[156]

2. *Sierrita Gas Pipeline, LLC*, 147 F.E.R.C. ¶ 61,192 (June 6, 2014).

Sierrita Gas Pipeline, LLC (Sierrita) proposed to build a cross-border natural gas pipeline from Pima County, Arizona, to Mexico.[157] The FERC granted the certificate and Presidential Permit to authorize Sierrita to site, construct, connect, operate, and maintain natural gas export and border crossing facilities.[158] However, in its order granting the certificate and permit, the FERC held a proposal that effectively allowed for a single open season for ROFR capacity and expansion capacity to be inconsistent with established policy.[159]

N. Pressure Commitments

1. *Gas Transmission Northwest LLC*, 143 F.E.R.C. ¶ 61,264 (2013).

In a compliance filing related to its ability to enter into pressure commitments, Gas Transmission Northwest LLC (GTN) revised its tariff to provide that, prior to executing a service agreement with a pressure commitment that would require GTN to dedicate additional capacity, GTN would post a notice of the proposed transaction on its website for five business days.[160] During this time, other shippers have the opportunity to obtain the same capacity "under the same terms but without a pressure commitment," on a first-come, first-serve basis.[161] The FERC, however, was concerned that the words "under the same

153. *Id.* at P 22.
154. *Encana Mrktg. (USA) Inc. v. Rockies Express Pipeline LLC*, 146 F.E.R.C. ¶ 61,161 at P 1 (2014).
155. *Id.* at P 20.
156. *Id.* at P 26.
157. 147 F.E.R.C. ¶ 61,192 at P 1.
158. *Id.* at P 3.
159. *Id.* at P 83.
160. *Gas Transmission Nw. LLC*, 143 F.E.R.C. ¶ 61,264 at P 1 (2013).
161. *Id.* at P 6.

terms" could be confusing, accidentally foreclosing the award of capacity to a potential shipper that submits a request absent the pressure commitment that includes terms that are better, rather than the "same," terms.[162] The FERC required GTN to revise the language

> to make clear that the generally applicable bid evaluation provisions of its tariff will govern to award the subject capacity to the shipper who values it most, which is not necessarily the first shipper that offers the same terms, but the shipper that offers the better or best terms within the posting period.[163]

O. Rate Cases

1. *El Paso Natural Gas Co.*, 145 F.E.R.C. ¶ 61,040 (2013).

The FERC issued Opinion No. 528, affirming in part and reversing in part an initial decision issued on June 18, 2012, that resolved the issues reserved for hearing in El Paso Natural Gas Company's (El Paso) general NGA section 4 rate case, which had been filed on September 30, 2010, in Docket No. RP10-1398-000 (2011 Rate Case).[164] The cost of service issues under review concerned certain operation and maintenance expenses. The FERC (i) affirmed the presiding judge's rejection of gas supply expense projections that fell outside of the test period;[165] (ii) reversed the presiding judge's holding permitting El Paso to book pension costs based on an actuarial study when no payments were made or accrued in the test period;[166] (iii) reversed the presiding judge's ruling on rate case expenses, finding that the three-year average rate case expense in the appropriate amount;[167] and (iv) affirmed the determination establishing compressor overhaul costs.[168]

The FERC rejected a shipper-led postage stamp rate design and rejected shippers' proposed automatic daily balancing provisions. The FERC approved El Paso's zone of delivery/contract path methodology, but rejected El Paso's proposal to equalize rates in California and bordering states.[169] It also rejected a proposal to use a "within basis" production zone rate methodology. The FERC reversed the presiding judge in one aspect, ordering El Paso to follow the FERC's policy of basing cost allocation on unadjusted billing determinants.[170] For return on equity, the FERC affirmed the presiding judge's selection of Boardwalk Pipeline Partners, L.P., TC Pipelines L.P., Spectra Energy Partners, L.P., and Williams Partners, L.P. as the proper proxy group.[171] The FERC determined that El Paso's financial and business risk did not warrant placing it well above the median return on equity (ROE) for the proxy group companies and set El Paso's

162. *Id.* at P 10.

163. *Id.*

164. *El Paso Natural Gas Co.*, 145 F.E.R.C. ¶ 61,040 at P 20 (2013), *order denying motion for reconsideration & motion to permit interlocutory appeal*, 146 F.E.R.C. ¶ 63,001 (2014).

165. 145 F.E.R.C. ¶ 61,040 at P 34.

166. *Id.* at P 48.

167. *Id.* at P 73.

168. *Id.* at P 61.

169. *Id.* at PP 243, 274.

170. *Id.* at 23.

171. 145 F.E.R.C. ¶ 61,040 at PP 621-22, 635.

allowed ROE at 10.55%, the median ROE of the proxy group companies.[172] Finally, the FERC made findings concerning the 1996 Settlement of El Paso's rate case in Docket No. RP95-363-008.[173] The FERC affirmed that article 11.2 of the settlement remains in effect and that El Paso could not reallocate shortfalls under the 1996 Settlement to non-settlement recourse customers, and determined that El Paso's proposed bifurcated cost of service is not just and reasonable.[174]

The FERC remanded the proceeding on two grounds. First, it reversed the presiding judge's finding that El Paso has met a 4,000 MMcf/d threshold to demonstrate that article 11.2(b) rate protections were not triggered and remanded the issue for determination of the appropriate remedy.[175] The FERC also ordered a supplemental hearing to determine an appropriate means to ensure that El Paso would comply with article 11.2(b) of the 1996 Settlement.[176]

2. *Southern Star Central Gas Pipeline, Inc.*, 147 F.E.R.C. ¶ 61,061 (2014).

The FERC approved Southern Star Central Gas Pipeline, Inc.'s uncontested offer of settlement in the form of a Stipulation and Agreement to resolve all issues related to its NGA section 4 rate case filed in Docket No. RP13-941-000.[177] The settlement set settlement rates based on a $238.5 million cost-of-service with a separate, incremental charge applicable to customers using the pipeline's Ozark Trails expansion facilities, and to a separate cost of service for the Elk City Storage market-based facility.[178] The Settlement Rates also reflected an annual gross amount of $7,750,000 associated with recovery of pension expense and Post-retirement Benefits Other than Pensions (PBOP) expenses.[179] The FERC found the settlement to be fair and reasonable and in the public interest.

3. *Trailblazer Pipeline Co.*, 147 F.E.R.C. ¶ 61,159 (2014).

The FERC approved Trailblazer Pipeline Company's (Trailblazer) uncontested settlement of its general NGA Section 4 rate case filed in Docket No. RP13-1031-000.[180] The "black box" settlement resulted in a cost of service of $21,059,447.[181] The primary issue Trailblazer sought to resolve in its rate case was recovery of fuel costs related to a compression-based expansion project that had been placed in service in 2002. In settlement, the parties agreed to maintain a bifurcated rate structure, with an embedded fuel component present in the base rates applicable to certain transportation on the existing system and fuel tracker

172. *Id.* at P 686.
173. *El Paso Natural Gas Co.*, 79 F.E.R.C. ¶ 61,028 (1997), *reh'g denied*, 80 F.E.R.C. ¶ 61,084 (1997).
174. 145 F.E.R.C. ¶ 61,040 at P 23.
175. *Id*.
176. *Id.* at P 24.
177. *S. Star Cent. Gas Pipeline, Inc.*, 147 F.E.R.C. ¶ 61,061 at PP 1, 3 (2014).
178. *Id.* at P 2.
179. *Id.*
180. *Trailblazer Pipeline Co.*, 147 F.E.R.C. ¶ 61,159 at P 1 (2014).
181. Offer of Settlement and Stipulation and Agreement, *Trailblazer Pipeline Co., LLC*, Art. 3.1, Docket No. RP13-1031-000 (filed Feb. 24, 2014).

for fuel use on the expansion system, with all shippers assessed a lost and unaccounted for gas retention percentage.[182] Trailblazer also agreed to separately track fuel and electric power costs related to the operation of its gas-fueled and electricity-powered compressor units.[183] The settlement agreement also ensured that certain non-Rate Schedule FTS shippers, which had not been required to pay expansion system fuel costs prior to the rate case even though their volumes used that capacity, were obligated to do so.[184] The FERC approved the settlement on May 29, 2014, after finding that it appeared to be fair, reasonable, and in the public interest.[185]

4. *Southern Natural Gas Co.*, 144 F.E.R.C. ¶ 61,023 (2013).

The FERC approved Southern Natural Gas Company's (Southern) May 2, 2013 Stipulation and Agreement (Settlement), filed in lieu of filing a NGA section 4 rate case, to extend and replace Southern's existing 2009 rate settlement.[186] The FERC determined that the Settlement reduced rates for all of Southern's customers, including a transportation rate decrease of 7% that would take effect September 1, 2013, and a cumulative 11% decrease that would take effect November 1, 2015.[187] Storage rates would also decrease by 17.2% effective September 1, 2013.[188] The Settlement also resolved a dispute over Southern's fuel tracker mechanism. The FERC approved the uncontested Settlement as fair and reasonable and in the public interest, and permitted it to become effective on September 1, 2013.[189]

5. *Enable Mississippi River Transmission, LLC*, 144 F.E.R.C. ¶ 61,230 (2013).

The FERC accepted Enable Mississippi River Transmission, LLC's (MRT) July 30, 2013 Settlement Agreement to resolve all issues in its NGA section 4 rate case filed in Docket Nos. RP12-955-000.[190] The FERC found that the Settlement resulted in a general rate reduction from the rates MRT had proposed in its filing and contained a two-year rate case moratorium to provide rate certainty for that period.[191] As a condition of the Settlement, MRT agreed to withdraw the Regulatory Compliance Cost Surcharge it had proposed in its filing and to withdraw its pending request for rehearing in Docket No. RP12-955-002. The FERC approved the Settlement without modification because it found that it appeared to be fair, reasonable, and in the public interest.[192]

182. *Id*. at P 3; *see also* 144 F.E.R.C. ¶ 61, 084 at PP 3-5 (2013) (stating Trailblazer's proposed changes).
183. *Id*.
184. *Id*.
185. *Id.* at P 3.
186. *S. Natural Gas Co., L.L.C.*, 144 F.E.R.C. ¶ 61,023 at P 1 (2013).
187. *Id*. at P 3.
188. *Id.*
189. *Id.* at P 20.
190. *Enable Miss. River Transmission, LLC*, 144 F.E.R.C. ¶ 61,230 at P 1 (2013).
191. *Id.* at P 2.
192. *Id*. at PP 2-3.

6. *WBI Energy Transmission, Inc.*, 147 F.E.R.C. ¶ 63,014 (2014).

The presiding Administrative Law Judge (ALJ) certified, as uncontested, WBI Energy Transmission, Inc.'s (WBI Energy) Offer of Settlement, filed on June 4, 2014, in Docket No. RP14-118-000.[193] The settlement resolves the general NGA section 4 rate case filed by WBI Energy on October 31, 2013. It permits WBI Energy to "roll into its system-wide rates the costs of three projects on its contiguous system, the Grasslands Pipeline Projects, the Sheyenne Expansion Project, and the Mapleton Extension, and to create separately-stated base rates and fixed fuel rates for two non-contiguous lateral projects, Garden Creek and Stateline."[194] The settlement also resulted in "a 'black box' total cost of service of $95,000,000."[195] In addition, it obligated WBI Energy to unbundle its fuel allocation and lost and unaccounted for gas and to separately state its percentages for each item in its next annual Fuel and Electric Power Reimbursement filing effective April 1, 2015.[196]

7. *Sea Robin Pipeline Co.*, 145 F.E.R.C. ¶ 61,292 (2014).

The FERC set Sea Robin Pipeline Company's (Sea Robin) general rate increases, proposed under NGA section 4, for hearing.[197] The proposed rate increases were accepted and suspended to be effective June 1, 2014, subject to refund and the outcome of a hearing. The FERC noted that the hearing should explore the issues raised with respect to Sea Robin's Hurricane Surcharge filing in Docket No. RP13-968-000, which the FERC accepted subject to the outcome of its general NGA section 4 rate case proceeding.[198] The FERC also accepted, effective January 1, 2014, proposed changes to Sea Robin's tariff increasing penalties for violations of an Operational Flow Order on Sea Robin's system from $1.00 to $25.00.[199] On July 2, 2014, the Chief ALJ issued an order suspending the procedural schedule while the parties finalized a comprehensive settlement in principle.[200]

8. *Paiute Pipeline Co.*, 146 F.E.R.C. ¶ 61,239 (2014).

The FERC set Paiute Pipeline Company's (Paiute) general NGA section 4 rate case for hearing on March 31, 2014.[201] The rate case will explore Paiute's proposals to establish term-differentiated rates and to roll-in costs associated with its 2011 Highway 50 Relocation Project. The FERC rejected as moot alternate tariff records without term differentiated rates filed by Paiute in the event the

193. *WBI Energy Transmission, Inc.*, 147 F.E.R.C. ¶ 63,014, 66,104 (2014).
194. *Id.* at P 2.
195. *Id.* at P 8.
196. *Id.* at P 13.
197. *Sea Robin Pipeline Co.*, 145 F.E.R.C. ¶ 61,292 at P 1 (2014).
198. *Id.* at P 22.
199. *Id.* at P 8.
200. Order of Chief Judge Granting Motion to Suspend Procedural Schedule and Waiving Answer Period, *Sea Robin Pipeline Co.*, Docket Nos. RP14-247-000 and RP13-968-000 (FERC issued July 2, 2014).
201. *Paiute Pipeline Co.*, 146 F.E.R.C. ¶ 61,239 at P 1 (2014).

FERC rejected Paiute's primary proposal.[202] The new rates will take effect, subject to refund and the outcome of a hearing, on September 1, 2014. The matter currently is set for hearing on January 20, 2015.

P. Rate Investigations

1. *Wyoming Interstate Co., L.L.C.*, 145 F.E.R.C. ¶ 61,005 (2013); *Viking Gas Transmission Co.*, 145 F.E.R.C. ¶ 61,235 (2013).

The FERC approved two uncontested settlements resolving all issues and terminating the proceedings related to its section 5 investigations into the rates of Wyoming Interstate Company (WIC)[203] and Viking Gas Transmission Company (Viking) and established hearing procedures.[204] On December 19, 2013, the FERC issued an order approving an uncontested settlement filed by Viking to resolve all issues, and the order terminated the proceeding.[205]

Q. Reservation Charge Credits

1. *Panhandle Eastern Pipe Line Co.*, 148 FERC ¶ 61,025 (2014).

The FERC, while denying Panhandle's second request for rehearing in this series of cases, approved Panhandle's revised tariff records as generally in compliance with the Commission's policy on reservation charge crediting, *force majeure*, and its earlier rulings.[206] First addressing Panhandle's argument, the Commission improperly converted a policy statement into a rule with the force of law, it pointed to *North Baja*[207] as precedent along with the affirmation of the FERC's policy on review, in which the court concluded "that the Commission had reasonably explained its decision for the purposes of the court's review under the APA."[208] The *North Baja* court determined the Commission's policy, precedent, and manner of implementation, which predated the Panhandle opinion, to be reasonable.[209] With regard to the FERC's section 5 burden, the FERC indicated that, since Panhandle's tariff failed to include any provision to provide for non-*force majeure* outages of primary firm service, its tariff was unjust and unreasonable.[210] The FERC reasoned that once it makes a *prima facie* showing that a pipeline tariff is unjust and unreasonable, the Commission may shift the burden to the pipeline to justify the tariff provisions.[211] Finally, with regard to whether Panhandle's previous settlement rates should have been given effect

202. *Id.* at 1 n.3 (explaining that Paiute had misfiled its alternate tariff record in the Commission's eTariff filing system).

203. *Wyo. Interstate Co.*, 141 F.E.R.C. ¶ 61,117 at P 1 (2012).

204. *Viking Gas Transmission Co.*, 141 F.E.R.C. ¶ 61,118 at P 1 (2012).

205. *Viking Gas Transmission Co.*, 145 F.E.R.C. ¶ 61,235 at P 17 (2013).

206. *Panhandle E. Pipe Line Co.*, 148 FERC ¶ 61,025 at PP 1, 5 (2014).

207. North Baja v. FERC, 483 F.3d 819, 823 (D.C. Cir. 2007), *aff'g*, *North Baja Pipeline, LLC*, 109 F.E.R.C. ¶ 61,159 (2004), *order on reh'g*, *North Baja Pipeline, LLC*, 111 F.E.R.C. ¶ 61,101 (2005).

208. 148 F.E.R.C. ¶ 61,025 at P 31.

209. *North Baja*, 483 F.3d at 820.

210. 148 F.E.R.C. ¶ 61,025 at P 40.

211. *Id.* at P 43.

before the imposition of reservation charge credits, the FERC reasoned that since "Panhandle's settlement did not contain a provision restricting the shippers rights under NGA section 5 to seek a change . . . regarding reservation charge crediting," there is nothing to suggest the settlement was premised on the absence of any reservation charge crediting provision.[212]

In its approval of Panhandle's compliance filing, the Commission required Panhandle to revise its proposed tariff language to limit its reduction in credits to the amount of secondary firm service used, as an alternative to the primary firm service not provided.[213] The FERC also required Panhandle to clarify that any proposed exemptions from crediting would be limited to situations where the pipeline's failure to deliver gas was due solely to the conduct of others or events not controllable by the pipeline.[214] The FERC also found as reasonable revisions to Panhandle's general terms and conditions (GT&C) section 8.8 that would ensure "that transactions from primary receipt points to primary delivery points will always have the highest scheduling priority."[215] Finally, the FERC affirmed its policy of allowing partial reservation charge crediting for outages of primary firm service required to comply with orders issued by PHMSA pursuant to section 60139(c) for a transitional two-year period.[216]

2. *Trailblazer Pipeline Co.*, 145 FERC ¶ 61,229 (2013).

The FERC accepted Trailblazer's non-rate changes related to reservation charge crediting.[217] Trailblazer proposed to modify its GT&C to calculate reservation charge credits based on the seven-day period before the posting date of its Monthly Maintenance Schedule, and also proposed to clarify how the credits would be calculated.[218] The Wyoming Pipeline Authority and Indicated Shippers requested that Trailblazer clarify its proposal to provide that reservation charges will be eliminated based on "the quantity of Gas, not to exceed the applicable MDQ, nominated Shipper's primary point(s) and that is not scheduled or delivered, whichever is greater."[219] Trailblazer agreed to make such change.[220]

3. *Iroquois Gas Transmission System, LP*, 145 FERC ¶ 61,233 (2013).

The FERC required Iroquois to either modify, or show cause why it should not, reservation charge crediting provisions filed by Iroquois following a FERC audit.[221] In its analysis of Iroquois' proposed provisions, the FERC held that Iroquois's proposed crediting provisions were not "in the same ballpark" as those required by FERC policy under the Safe Harbor and No-Profit methods because

212. *Id.* at PP 57-58.
213. *Id.* at P 85.
214. *Id.* at P 87.
215. 148 F.E.R.C. ¶ 61,025 at P 93.
216. *Id.* at P 96.
217. *Trailblazer Pipeline Co.*, 145 F.E.R.C. ¶ 61,229 at P 1 (2013).
218. *Id.* at P 55.
219. *Id.* at P 56.
220. *Id.* at P 57.
221. *Iroquois Gas Transmission Sys.*, 145 F.E.R.C. ¶ 61,233 at P 1 (2013).

they did not provide for equitable risk sharing.[222] With regard to Iroquois' proposed "confirmed properly and timely" limitation on credits for both *force majeure* and non-*force majeure* events, the FERC found the phrase vague and "fails to define the circumstances in which the confirmation requirement is and is not applicable."[223] Iroquois was directed to file revisions "expressly applying this limitation to proposed exemptions in section 20.2(f)(v) based on the various types of conduct by the shipper or the upstream or downstream facilities operators."[224]

With respect to the volume that would have been used by the shipper when given advanced notice of an outage, the FERC stated, "Iroquois may propose to calculate reservation charge credits based on any reasonably representative measure of historical usage, including an average of several years' usage, so long as its proposal is not structured so as to minimize the amount of credits it must give."[225] The FERC confirmed separately that shippers should remain eligible for reservation charge credits when they make alternative arrangements for gas deliveries.[226] The FERC also granted the right for shippers to receive reservation charge credits, even where a shipper's negotiated rate agreement does not require such credits, finding that Iroquois' negotiated rate contracts contain Memphis clauses incorporating any changes Iroquois may make to its GT&C from time to time.[227] A service agreement with a Memphis clause, the Commission reasoned, "automatically give[s] shippers any increased rights which may be provided by changes in the terms and conditions of service in a pipeline's tariff."[228] Accordingly, Iroquois was ordered to provide that its section limiting credits in negotiated rate agreements would apply only after the effective date of the tariff provision.[229]

4. *Chesapeake Energy Mktg., Inc. v. Midcontinent Express Pipeline LLC*, 145 FERC ¶ 61,041 (2013).

The FERC granted a complaint filed by Chesapeake over Midcontinent's failure to provide reservation charge credits that Chesapeake claimed it was owed under section 2.2 of Midcontinent's GT&Cs.[230] At the time of the event, Chesapeake took service from capacity leased by Midcontinent through Enogex, with Midcontinent flowing through Leased Capacity Charges for such use.[231] Midcontinent issued a notice that the remediation work would be on Enogex's system and that shippers using Enogex leased capacity, including Chesapeake,

222. *Id.* at P 39.
223. *Id.* at P 45.
224. *Id.* at P 46.
225. *Id.* at P 52.
226. *Id.* at P 63.
227. 145 F.E.R.C. ¶ 61,233 at P 67.
228. *Id.* at P 68 (citing *Regulation of Short-Term Natural Gas Transp. Services & Regulation of Interstate Natural Gas Transp. Services*, 101 F.E.R.C. ¶ 61,127 at P 46 (2002), *reh'g denied*, 106 F.E.R.C. ¶ 61,088 at PP 64-65 (2004), *aff'd*, AGA v. FERC, 428 F.3d 255 (D.C. Cir. 2005)).
229. 145 F.E.R.C. ¶ 61,233 at P 71.
230. *Chesapeake Energy Mktg., Inc. v. Midcontinent Express Pipeline LLC*, 145 F.E.R.C. ¶ 61,041 at P 2 (2013).
231. *Id.* at P 5.

would be responsible for reservation charges on Midcontinent system Zone 1 and Zone 2 during the outage, since their full MDQ would be available on that system.[232] Chesapeake challenged the notice, stating that "Midcontinent's tariff required it to provide reservation charge credits for its entire transportation path, if any of that path was unavailable."[233] For Chesapeake, the Commission summarized, "remediation work on the Lease Capacity would prevent it from scheduling service from its primary receipt points on the Leased Capacity to its primary delivery points in Zones 1 and 2."[234] The outage on the Leased Capacity lasted a month and each day Chesapeake nominated a total of 200,000 dth/day from its primary receipt points located on the Leased Capacity to its Primary Delivery Points in Zones 1 and 2.[235] The FERC noted that section 2.2(d)(1) of Midcontinent's GT&Cs "requires that 'the applicable Reservation Charge and any related reservation-based surcharges shall be eliminated' for undelivered quantities, unless one of the exceptions in section 2.2(d)(1) or (2) [of Midcontinent's tariff] applies."[236] The first exception is if the shipper uses secondary point service, but that would not apply in this instance: Chesapeake did not use secondary point service during the outage.[237] The second exception would be if the failure to deliver was the result of shipper conduct or the downstream facilities point operator, but that would not apply in this instance either: the failure to deliver was the result of remediation work on the capacity leased from Enogex, far upstream.[238] The third exception occurs when there is a *force majeure* event, but here Midcontinent argued its failure to deliver was the result of *force majeure*.[239] The FERC also summarily rejected all of Midcontinent's other arguments based on the premise that the Leased Capacity is not part of its system, but rather confirms that Midcontinent appropriately controls the Leased Capacity and all service over that capacity is subject to FERC Gas Tariff.[240]

R. Scheduling

1. *Tennessee Gas Pipeline Co.*, 145 F.E.R.C. ¶ 61,058 (2013) *reh'g denied*, 147 F.E.R.C. ¶ 61,117 (2014).

The FERC approved a proposal by Tennessee Gas Pipeline Co. (Tennessee) pursuant to NGA section 4 to modify its tariff to elevate the scheduling priority of firm transportation service from a secondary in-path receipt point to a primary delivery point over all other secondary in-path services.[241] The FERC emphasized that NGA section 4 grants pipelines "the primary initiative" to propose tariff

232. *Id.* at P 8.
233. *Id.* at P 9.
234. *Id.*
235. *Id.* at PP 12, 33.
236. 145 F.E.R.C. ¶ 61,041 at P 33.
237. *Id.* at P 34.
238. *Id.*
239. *Id.* at P 35.
240. *Id.* at PP 36-41.
241. *Tenn. Gas Pipeline Co.*, 145 F.E.R.C. ¶ 61,058 at PP 1-2 (2013) *reh'g denied*, 147 F.E.R.C. ¶ 61,117 (2014).

changes.[242] The FERC again relied on *Texas Eastern*, rejecting arguments that the proposal contravened the intent in Order No. 637-A by differentiating within secondary in-path priority.[243] The FERC found that higher scheduling priority for secondary-to-primary in-path service would provide primary delivery point shippers "greater certainty . . . to access low cost natural gas supplies on different parts of Tennessee's system."[244]

2. *Transcontinental Gas Pipe Line Co.*, 145 F.E.R.C. ¶ 61,130 (2013), *on reh'g & compliance*, 147 F.E.R.C. ¶ 61,033 (2014), *reh'g pending*.

The FERC accepted Transco's proposed tariff revision to clarify that all receipt points within a firm shipper's "contract path" are considered "primary" receipt points under that contract, irrespective of whether the receipt points are specifically identified in the contract.[245] The FERC found that, during its restructuring proceedings, Transco did not assign firm shippers specific receipt point capacity, and did not allocate specific receipt point capacity entitlements at each receipt point.[246] In the event of inadequate capacity at a receipt point to meet the full nominations, Transco allocated the point capacity *pro rata*.[247]

S. Termination

1. *Natural Gas Pipeline Co. of America*, 144 F.E.R.C. ¶ 61,064 (2013).

The FERC addressed a non-conforming service agreement in which, among other things, Natural Gas Pipeline Co. agreed to permit the customer, a chemical manufacturer, to terminate the agreement in the event of a permanent shutdown of its chemical plant.[248] Although the FERC has previously accepted similar termination provisions, the FERC stated that it viewed early termination provisions as "valuable rights, which present too much potential for undue discrimination unless they are offered in the pipeline's tariff pursuant to generally applicable conditions."[249] Accordingly, the FERC accepted the service agreement and associated tariff records, but directed Natural Gas Pipeline Co. to either eliminate the termination right provision or revise its tariff to offer such a provision to similarly situated shippers.[250]

2. *Northwest Pipeline LLC*, 147 F.E.R.C. ¶ 61,019 (2014).

Northwest Pipeline LLC (Northwest) sought to change its tariff "to limit the rights of a shipper with a [contract containing] a Grandfathered Unilateral

242. 145 F.E.R.C. ¶ 61,058 at P 26.
243. 147 F.E.R.C. ¶ 61,117 at P 21.
244. *Id.* at P 11.
245. *Transcon. Gas Pipe Line Co.*, 145 F.E.R.C. ¶ 61,130 at PP 1, 5 (2013).
246. *Transcon. Gas Pipe Line Co.*, 147 F.E.R.C. ¶ 61,117 at P 19.
247. *Id.* at P 22.
248. *Natural Gas Pipeline Co. of Am.*, 144 F.E.R.C. ¶ 61,064 at PP 1-4 (2013).
249. *Id*. at P 10 (footnote omitted).
250. *Id*.

Termination Right to include that right in a permanent" capacity release.[251] This unilateral termination right, coupled with a contractual evergreen clause, permitted certain firm shippers to "terminate all or any portion of their contracts either at the expiration of the primary term, or upon each anniversary thereafter, by providing at least twelve [months' notice to Northwest] prior to the termination date."[252] Moreover, a shipper whose contract included the Grandfathered Unilateral Termination Right could include that right in a permanent release of its capacity to another shipper.[253] Northwest proposed to require the replacement shipper in such a release to elect a term of at least ten years in order to retain the Grandfathered Unilateral Termination Right, explaining that shippers with this right were not motivated to enter into long term agreements because they were not at risk of losing their capacity when it is in evergreen rollover status.[254] The FERC accepted Northwest's proposal, noting that it "does not require pipelines to permit a permanent [capacity] release unless they are financially indifferent to the release."[255] The FERC agreed with Northwest that it was "not financially indifferent to allowing replacement shippers to take over unilateral evergreen rights without committing to taking capacity for a longer term," because it made efficient planning of the pipeline's operations difficult in the current market.[256] The FERC also stated that the capacity release option was separate from the termination right and no contract required Northwest to allow permanent releases "without imposing a reasonable condition to ensure the financial indifference of the pipeline, such as the ten-year primary term requirement proposed by Northwest here."[257]

III. INFRASTRUCTURE

A. Pipelines

1. *Houston Pipe Line Co.*, 146 F.E.R.C. ¶ 61,195 (2014).

The FERC approved Houston Pipe Line's request for authorization[258] and granted a Presidential Permit to install a twenty-four-inch diameter pipeline by horizontal directional drill under the Rio Grande River in Hidalgo County, Texas to the international border with the Republic of Mexico in the vicinity of the City of Reynosa, State of Tamaulipas.[259] The FERC found the public interest was met

251. *Nw. Pipeline LLC*, 147 F.E.R.C. ¶ 61,019 at P 1 (2014).
252. *Id*. at P 2.
253. *Id*. at P 3.
254. *Id*. at PP 3-4.
255. *Id*. at P 10.
256. *Id*.
257. *Id*. at P 11.
258. *Houston Pipe Line Co.*, 146 F.E.R.C. ¶ 61,195 at P 2 (2014). Houston Pipe Line's application was made under section 3 of the NGA. 15 U.S.C. § 717b (2012), 18 C.F.R. pt. 153 (2013) (implementing regulations). NGA section 3 further provides that the exportation and importation of natural gas between the United States and "a nation with which there is in effect a free trade agreement requiring national treatment for trade in natural gas, . . . shall be deemed to be consistent with the public interest, and applications for such importation and exportation shall be granted without modification or delay." 15 U.S.C. §§ 717b(b)-(c).
259. 146 F.E.R.C. ¶ 61,195 at PP 1-2, 4 (2014).

by the application and swiftly approved the request, following its issuance of an EA, under section 3 of the NGA because of the existing free trade agreement[260] in place between the United States and Mexico. After construction, Houston Pipe Line was required to restore the disturbed areas, which the FERC described as having minimal impacts on landowners, in accordance with FERC guidelines.[261] The FERC concluded its approval of the Houston Pipe Line proposal "would not constitute a major federal action significantly affecting the quality of the human environment."[262]

2. *Columbia Gas Transmission, LLC*, 146 FERC ¶ 61,075 (2014).

The FERC authorized Columbia to replace and expand its pipeline facilities in Greene and Washington Counties, Pennsylvania, and increase capacity at its Waynesburg Compressor Station.[263] Capacity was awarded at negotiated rates pursuant to an open season. Because the estimated incremental rate is lower than the base reservation rate currently in effect and there would be no impact on fuel, the FERC approved the use of Columbia's existing system rates as the initial recourse rates.[264] Columbia also sought a predetermination of rolled in rate treatment because the agreements with the two shippers for the expansion capacity are at negotiated rates higher than the proposed recourse rate.[265] Because the projected costs of the negotiated rate agreements would exceed the cost of service, the FERC indicated that "absent changed circumstances, rolled-in rate treatment . . . would not require subsidies from existing customers;" this determination is subject to no significant allocation of costs to the project in a future capital cost recovery proceeding under the modernization settlement.[266]

3. *Columbia Gas Transmission, LLC*, 145 F.E.R.C. ¶ 61,069 (2014).

The FERC granted Columbia's application seeking authorization to construct approximately 12.6 miles of pipeline from Summers County, West Virginia to Giles County, Virginia (Giles County Project).[267] Following an open season, Columbia signed a precedent agreement with a single shipper for service utilizing the full capacity of the project for a twenty-year term.[268] The FERC accepted Columbia's proposal to charge an incremental rate for the project, but required Columbia to adjust the rate to reflect the accumulated depreciation that will be accrued over the course of the year.[269]

260. *Id.* at P 10. The free trade agreement is the North American Free Trade Agreement (NAFTA).

261. *Id.* at P 11.

262. *Id.* at P 19.

263. *Columbia Gas Transmission, LLC*, 146 FERC ¶ 61,075 at PP 1-2 (2014). The authorization was granted under sections 7(b) and (c) of the NGA and part 157, Subpart A of the FERC's regulations. *Id.* at P 1.

264. *Id.* at P 26.

265. *Id.* at P 28.

266. *Id.* at PP 29, 31.

267. *Columbia Gas Transmission, LLC*, 146 F.E.R.C. ¶ 61,069 at P 1 (2014). Columbia's application was made under section 7(c) of the NGA. *Id.*

268. *Id.* at P 4.

269. *Id.* at PP 14, 19.

4. *Gulf Crossing Pipeline Co.*, 144 F.E.R.C. ¶ 61,196 (2013).

The FERC approved Gulf Crossing Pipeline Company's request for a certificate of public convenience and necessity authorizing it to construct and operate natural gas pipeline facilities to serve Panda Sherman Power, LLC's electric power plant under construction in Grayson County, Texas.[270] The FERC found Gulf Crossing's proposal to charge its existing system-wide rates as the initial recourse rates for service on the proposed facilities appropriate, avoiding subsidizations by existing customers.[271] The FERC denied Gulf Crossing's request for a predetermination of rolled-in rate treatment in its next general rate proceeding because it determined that the contract quantity and the negotiated rates were "less than the annual cost of service in each of the first three years of operation."[272]

5. *Dominion Transmission, Inc.*, 144 F.E.R.C. ¶ 61,183 (2013).

The FERC approved, with appropriate conditions, Dominion Transmission, Inc.'s application for a certificate of "public convenience and necessity authorizing it to construct and operate facilities in Greene and Westmoreland Counties, Pennsylvania, known as the Natrium-to-Market Project."[273] Through the project's open season, Dominion executed precedent agreements with four customers fully subscribing the Natrium-to-Market Project.[274] Dominion proposed "to provide the proposed firm transportation service at the existing system maximum rates, including all other applicable rates, charges, surcharges, penalties, and fuel retention, under Dominion's Rate Schedule FT."[275] Dominion also sought rolled-in rate treatment.[276] The FERC approved Dominion's proposal to use the existing Rate Schedule FT reservation rate, "as well as the application of all other appropriate charges under the Rate Schedule, including Dominion's existing fuel retention percentage, as the initial recourse rate for the new capacity."[277] The FERC found that projected revenues for the project exceed Dominion's estimated incremental cost of service and granted a pre-determination to "roll the costs of the project into Dominion's system rates in its next NGA section 4 general rate proceeding, absent any significant change in material circumstances."[278]

270. *Gulf Crossing Pipeline Co.*, 144 F.E.R.C. ¶ 61,196 at P 1 (2013). Gulf Crossing's application was made under section 7(c) of the NGA. *Id.*

271. *Id.* at P 13.

272. *Id.* at P 16.

273. *Dominion Transmission, Inc.*, 144 F.E.R.C. ¶ 61,182 at P 1 (2013). Dominion Transmission's application was made under section 7(c) of the NGA and Part 157 of the Commission's regulations. *Id.*

274. *Id.* at P 5. The four customers were: Chesapeake Energy Marketing, Inc., HG Energy, LLC, BP Energy Co., and TOTAL Gas and Power North America, Inc. *Id.* at n.6.

275. *Id.* at P 6.

276. *Id.*

277. *Id.* at P 18.

278. *Id.* at P 19.

6. *Discovery Gas Transmission LLC*, 143 F.E.R.C. ¶ 61,171 (2013).

The FERC authorized Discovery to "construct and operate a new junction platform in South Timbalier Block 283 offshore Louisiana in the Gulf of Mexico, new pipeline facilities that will extend Discovery's existing system to the new platform, an emergency outage lateral pipeline, and other appurtenant facilities."[279] Discovery proposed to "recover its project costs through an incremental rate, using a levelized rate design (based on adjustments to depreciation and negative salvage) over a 40-year period."[280] Discovery proposed a "levelized cost-of-service by varying its depreciation expense for rate purposes to recover 100 percent of its investment over the 40-year useful life of the facilities."[281] The FERC further concluded that for "rate levelization proposals, it is only appropriate to record a regulatory asset for the difference between book depreciation and negative salvage expense and the amount of depreciation and negative salvage included in rates to the extent the pipelines capacity is subscribed."[282] Upon rehearing,[283] the FERC accepted Discovery's assertion that it specifically used thirty-inch diameter pipeline in sizing the mainline extension to accommodate system pigging needs.[284] The FERC further approved Discovery's initially proposed incremental recourse rates for service.[285] The FERC "require[d] Discovery to file a cost and revenue study after four years of operation of the extension justifying its incremental initial rates . . . to include a cost and revenue study in the form specified in section 154.313 of the regulations to update cost of service data."[286]

7. *DCP Midstream, LP*, 145 F.E.R.C. ¶ 62,229 (2013).

The FERC granted DCP authority to construct the Lucerne Residue Line "connecting DCP's new non-jurisdictional natural gas processing facilities with the interstate natural gas pipeline system of Colorado Interstate Gas Company (CIG), located in Weld County, Colorado."[287] The FERC found that "[s]ince DCP ha[d] no existing gas customers, there [was] no need to consider whether existing customers will subsidize the addition of new facilities."[288] The FERC further "found that the public interest would not be served by subjecting DCP to all of the regulatory requirements applicable to conventional natural gas pipeline companies."[289] Therefore, the FERC granted DCP's request for waiver of the Commission's applicable regulatory requirements. The FERC required DCP to

279. *Discovery Gas Transmission LLC*, 143 F.E.R.C. ¶ 61,171 at P 1 (2013).

280. *Id.* at P 14.

281. *Id.* at P 15.

282. *Id.* at P 32 (citing *Millennium Pipeline Co., L.L.C.*, 124 F.E.R.C. ¶ 61,139 at P 31 (2008)).

283. *Discovery Gas Transmission LLC,* 145 F.E.R.C. ¶ 61,145 (2013). Discovery's request for rehearing was granted. *Id.* at P 1.

284. *Id.* at P 9.

285. *Id.*

286. *Id.* at P 10.

287. *DCP Midstream, LP,* 145 F.E.R.C. ¶ 62,229, 64,502 (2013).

288. *Id.* ¶ 64,503.

289. *Id.*

"apply for blanket transportation authority under Part 284 of the Commission's regulations within 30 days of DCP's receipt of any *bona fide* requests to provide firm service on the Lucerne Residue Line."[290] The FERC "granted a blanket construction certificate authorizing performance of certain routine activities and transactions in conjunction with this operation of the Lucerne Residue Line, pursuant to Part 157, Subpart F of the Commission's regulations."[291]

8. *Columbia Gas Transmission, LLC*, 145 FERC ¶ 61,257 (2013).

The FERC granted a certificate for Columbia to construct and operate a compressor station in Washington County, Pennsylvania, and to add compression to an existing compressor station in Gilmer County, West Virginia.[292] The project is known as the Smithfield III Expansion. The expansion will provide an additional 444,000 dth/d of firm transportation to the Leach, Kentucky interconnect on Columbia Gulf.[293] Columbia proposed "to use its existing Rate Schedule FTS reservation rate and all applicable charges and surcharges as the initial recourse rate" for firm service on the project.[294] Because the incremental rate to recover the costs of the project would be lower than the existing rate for service, the use of the existing system rates as an initial recourse rate was deemed to be appropriate.[295] In addition, the FERC determined that the "incremental rate calculated to recover the costs of the proposed project is less than the applicable system rate for service," and therefore, no subsidy is levied upon existing customers.[296] The FERC granted a pre-determination of rolled-in rate treatment because Columbia demonstrated that its projected revenues for the project would exceed its incremental cost of service and the FERC granted the request, absent any significant change in circumstances.[297] The FERC also granted Columbia's request to charge generally applicable system fuel and lost and unaccounted-for retention for project services because "existing shippers will not subsidize or be adversely affected by fuel changes resulting from th[e] project."[298]

9. *Eastern Shore Natural Gas Co.*, 145 F.E.R.C. ¶ 62,153 (2013).

The FERC granted Eastern Shore's application for a certificate of public convenience and necessity authorizing it "to construct and operate the White Oak Lateral Project located in Kent County, Delaware."[299] The proposed project would enable Eastern Shore to provide 55,200 dth/d of firm transportation service for

290. *Id.* ¶¶ 64,503-04.
291. *Id.* ¶ 64,504.
292. *Columbia Gas Transmission, LLC*, 145 F.E.R.C. ¶ 61,257 at P 1 (2013). Authorization was requested by Columbia under section 7(c) of the NGA and Part 157 Subpart A of the FERC's regulations. *Id.*
293. *Id.*
294. *Id.* at P 17.
295. *Id.* at P 18.
296. *Id.* at P 13.
297. *Id.* at P 20.
298. *Id.* at P 22.
299. *E. Shore Natural Gas Co.*, 145 F.E.R.C. ¶ 62,153 at P 1 (2013). Eastern Shore's application was made under section 7(c) of the NGA. *Id.*

Calpine Energy Services, L.P. (Calpine).[300] Garrison Energy Center, LLC (GEC) and Eastern Shore proposed to develop the Garrison Energy Center, a proposed 309 megawatt combined cycle power plant.[301] "Eastern Shore and Calpine executed a binding Precedent Agreement [contemplating] that they execute a long-term service agreement under Eastern Shore's new Rate Schedule Delivery Lateral Firm Transportation (DLFT)."[302] "GEC and Eastern Shore obtained a $2.5 million Infrastructure Grant from the State of Delaware to partially offset the cost of constructing the White Oak Lateral Project."[303] As a result of the open season Eastern Shore conducted from January 2 through January 11, 2013, GEC was the only shipper to subscribe for 55,200 dth/d of transportation service. The proposed White Oak Lateral Project was fully subscribed.[304] "The White Oak Lateral Project will consist of approximately 5½ miles of 16-inch diameter pipeline lateral, one mainline valve assembly and a new delivery point meter and regulation station."[305] The total estimated cost of the proposed project is $11,200,000.[306] "The Project is designed to provide 55,200 [dth/d] of firm natural gas transportation service to the proposed Garrison Energy Center."[307] The FERC approved Eastern Shore's proposal to provide incremental service under the proposed DLFT and Delivery Lateral Interruptible Transportation (DLIT) Rate Schedules. The FERC further approved Eastern Shore's corrected DLFT recourse reservation rate of $2.5342 per dth-month and commodity (or usage) rate of $0.0000 per dth, and the corrected DLIT rate of $0.0833 per dth.[308] The FERC found that "Eastern Shore's proposed initial Fuel Retention Rate of 0.00%, and its proposed initial lost and unaccounted for (LAUF) Rate of 0.00 percent are appropriate.[309] However, the FERC required Eastern Shore to "adjust its LAUF percentage in its first annual Fuel Retention & LAUF filing that occurs after service commences on the White Oak Lateral" and "to ensure that LAUF costs be allocated to the incremental service under Rate Schedules DLFT and DLIT."[310]

10. *Columbia Gas Transmission, LLC*, 145 FERC ¶ 61,153 (2013).

The FERC authorized Columbia to construct and operate its proposed Line MB Expansion in Baltimore and Hartford Counties, Maryland.[311] Specifically, the Line MB Expansion loops part of Columbia's Line MA with the construction of 21.1 miles of 26-inch diameter pipeline from the terminus of the existing Line MB near Owings Mills in Baltimore County, Maryland to the Rutledge

300. *Id.*
301. "Calpine is an affiliate of GEC and both companies are subsidiaries of the Calpine Corporation." *Id.* at n.1.
302. *Id.*
303. *Id.* at P 3.
304. *Id.* at P 4.
305. *Id.* at P 5.
306. *Id.*
307. *Id.*
308. *Id.* at P 17.
309. *Id.*
310. *Id.*
311. *Columbia Gas Transmission, LLC*, 145 F.E.R.C. ¶ 61,153 at P 1 (2013).

Compressor Station in Hartford County, Maryland, and enables crossover flow between lines MB and MA with the installation of crossover pipelines at various meter stations.[312] Mainline valves and pig launchers are also part of the expansion plans.[313] Proposed as part of its seminal infrastructure modernization plan,[314] the Line MB Expansion is expected to go into service as part of two separate phases on October 31, 2013, and October 31, 2014.[315] The facilities are estimated to cost approximately $131.9 million and Columbia sought predetermination from the FERC for rolled-in rate treatment for those costs.[316] Under the FERC's Certificate Policy Statement,[317] including costs that will reduce service outages and improve reliability and system integrity in existing customers' rates does not constitute subsidization.[318] Moreover, a recent settlement between Columbia and its customers, approved by the FERC, explicitly included the costs associated with the proposed facilities.[319] Columbia stated the specific purpose of the Line MB Expansion was "not to add capacity that it could sell, but to increase system reliability and operational flexibility."[320] By operating its system from the Loudon compressor to Rutledge with a "system flexibility" delivery of 19,800 dth/day at Rutledge and reserving receipt of the same quantity (less compressor fuel) at Loudon, the firm capacity available for sale will be the same before and after the project.[321] This flexibility is required by Columbia, along with the increase in capacity, to protect the system when operations impair Line MA or if there were a catastrophic failure.[322] In accordance with its modernization settlement with its shippers, Columbia will recover the costs of the Line MB extension through its capital cost recovery mechanism,[323] which permits "Columbia to make annual limited section 4 filings during the five-year initial term of the mechanism."[324] The FERC therefore granted the request for rolled-in treatment as consistent with the Certificate Policy Statement's criteria.[325] Numerous parties filed requests for rehearing based on the need for the project and an environmental impact statement; each was denied, relying on the original order and record.[326]

312. *Id.* at P 3.

313. *Id.*

314. *Columbia Gas Transmission, LLC*, 142 F.E.R.C. ¶ 61,062 at P 4 (2013).

315. 145 F.E.R.C. ¶ 61,153 at P 4.

316. *Id.* at P 5.

317. *See generally* Statement of Policy, *Certification of New Interstate Natural Gas Pipeline Facilities*, 88 F.E.R.C. ¶ 61,227 at n.12 (1999).

318. 145 F.E.R.C. ¶ 61,153 at P 12.

319. *Columbia Gas Transmission, LLC*, 142 F.E.R.C. ¶ 61,062 at P 1 (2013).

320. 145 F.E.R.C. ¶ 61,153 at P 16.

321. *Id.* at P 17.

322. *Id.* at PP 19-21.

323. Gas Tariff, Baseline Tariffs, Gen. Terms and Conditions, Capital Cost Recovery Mechanism, 1.0.0, F.E.R.C. Docket No. RP13-00584-000 at P 52.1 (Mar. 1, 2013).

324. 145 F.E.R.C. ¶ 61,153 at P 24 n.12.

325. *Id.* at P 25.

326. *See generally Columbia Gas Transmission, LLC*, 146 F.E.R.C. ¶ 61,116 at P 1 (2014).

11. *Net Mexico Pipeline Partners, LLC*, 145 FERC ¶ 61,112 (2013).

The FERC found that the construction was necessary to meet the expanding fuel demand for power generation and industrial activity in Mexico, and would promote free trade,[327] and approved Net Mexico Pipeline Partners' (NET Mexico) request for authorization and "Presidential Permit to site, construct, connect, operate, and maintain a border-crossing facility for the export of natural gas . . . at the international boundary between the United States and Mexico in Starr County, Texas."[328] "NET Mexico propose[d] to construct approximately 1,400 feet of 48-inch diameter pipeline extending from . . . Starr County, Texas to the international border," constructed using horizontal directional drilling techniques to install pipeline beneath the Rio Grande River.[329] The facility will have a design capacity of 2.1 bcf/d and a maximum allowable operating pressure (MAOP) of 1,480 pounds per square gauge (psig).[330] The cost is estimated at $2.7 million.[331] The facility will be connected to a 120-mile intrastate pipeline with 2.1 bcf/d total capacity, which in turn will connect to a header system interconnecting with six intrastate pipelines, four processing plants, and, farther downstream, two interstate pipelines.[332] NET Mexico intends to later seek approval to provide interruptible transportation service on behalf of two interstate pipelines, under section 311 of the NGPA.[333]

B. Storage Projects

1. *Arlington Storage Co.*, 147 FERC ¶ 61,120 (2014).

Arlington filed an application for authorization to expand its Seneca Lake Storage Project, located in Schuyler County, New York, by converting two existing interconnected bedded salt caverns (Gallery 2), previously used for liquefied petroleum gas storage, to natural gas storage.[334] The Gallery 2 expansion would add 0.55 bcf of working gas capacity, bringing the total working gas capacity for the Seneca Lake Project to 2.00 Bcf.[335] Arlington held a non-binding open season for the new capacity and "received expressions of interest from six prospective customers in the total amount of 6.2 Bcf."[336]

The FERC imposed several engineering conditions on Arlington, including annual inventory verification tests, sonar surveys every five years to ensure the integrity of the caverns, periodic assessments of all the cavern wells, and

327. *Id*. at P 14.
328. *Id.* at 1. Authorization was requested under section 3 of the NGA. 15 U.S.C. § 717b (2012), 18 C.F.R. pt. 153 (2013) (implementing regulations).
329. *Id.* at P 4.
330. *Id*.
331. *Id.*
332. *Id*. at P 5.
333. *Id*. at P 7.
334. *Arlington Storage Co.*, 147 F.E.R.C. ¶ 61,120 at P 1 (2014).
335. *Id.* at P 5.
336. *Id.* at P 10.

continued monitoring of both Galleries for any gas loss or migration.[337] Upon review of the environmental assessment, the FERC concluded: there will be no ozone or greenhouse gas emissions associated with the electric motor-driven compressor unit;[338] construction and operation of the Gallery 2 project will have "no significant impact on land use, aesthetics, or impact the local economy;"[339] the project will "not result in significant cumulative impacts on regional air quality;"[340] "the project operation will not result in cumulative increased risks to public health;"[341] there will be "no significant impact on environmental resources due to geologic hazards or from the geologic framework present in the [project] area;"[342] the "spill plan will adequately protect groundwater and surface water resources;"[343] construction and operation of the project will not significantly affect migratory birds;[344] alternative storage projects would "result in greater construction, environmental, and landowner impacts" compared to the proposed project;[345] and an Environmental Impact Statement is not required because approval of the proposal does not constitute "a major federal action significantly affecting the quality of the human environment."[346]

2. *Gulf South Pipeline Co.*, 146 FERC ¶ 61,149 (2014).

Gulf South and Petal filed an application requesting "authority for Petal to abandon by lease certain storage capacity," and for Gulf South to acquire that capacity by lease.[347] Concurrently, Gulf South filed tariff records proposing a new Alternative No-Notice Service (NNS-A).[348] Both Gulf South and Petal are operating subsidiaries of Boardwalk Pipeline Partners, LP. The FERC granted the requested abandonment and lease authority, finding that the proposal satisfied the requirements of its Certificate Policy Statement,[349] would promote more efficient use of existing facilities, and would provide enhanced scheduling flexibility for gas-fired electric generation.[350] The FERC also approved the lease rates between the affiliated applicants, noting that the proposed rates are the average market-based rates charged by Petal to its unaffiliated shippers, and thus reflect prices consistent with competitive outcomes.[351]

337. *Id.* at PP 23-27.
338. *Id.* at P 59.
339. 147 F.E.R.C. ¶ 61,120 at P 65.
340. *Id.* at P 69.
341. *Id.* at P 73.
342. 147 F.E.R.C. ¶ 61,120 at P 94.
343. *Id.* at P 99.
344. *Id.* at P 103.
345. *Id.* at P 107.
346. *Id.* at P 108.
347. *Gulf South Pipeline Co.*, 146 F.E.R.C. ¶ 61,149 at P 1 (2014).
348. *Id.*
349. *Id.* at PP 17-20 (citing *Certification of New Interstate Natural Gas Pipeline Facilities*, 88 F.E.R.C. ¶ 61,227 (1999), *order on clarification*, 90 F.E.R.C. ¶ 61,128 (2000), *order on clarification*, 92 F.E.R.C. ¶ 61,094 (2000)).
350. *Id.* at PP 21-22.
351. *Id.* at P 30.

The FERC rejected the concerns of several interveners that the new NNS-A service will degrade the quality of service to existing shippers, finding that Gulf South will only provide NNS-A service if capacity is available, in a manner that will not adversely affect existing firm service.[352] The FERC also found that Gulf South's proposed scheduling priorities for NNS-A service are appropriate.[353] Additionally, the FERC approved Gulf South's proposed rate design for the storage cost component of the rates, but required revisions to the usage charge because it assumed 100% use of nominated and no-notice, unnominated contract quantities and thus could result in over-recovery.[354] Finally, the FERC rejected proposed tariff language that would have inhibited the creation of a market center within the shared storage facility at issue.[355] On March 27, 2014, Gulf South filed to accept the certificate and revise its tariff records to comply with the February 28, 2014 Order.

352. *Id.* at PP 57-59.
353. 146 F.E.R.C. ¶ 61,149 at P 60.
354. *Id.* at PP 69-75.
355. *Id.* at PP 92-94.

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