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) and the United States Courts of Appeals in the area of natural gas regulation between July 1, 2012 and June 30, 2013.*

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I. RULEMAKING ACTIONS

A. Coordination Between the Natural Gas and Electricity Markets

The Federal Energy Regulatory Commission (FERC or Commission) issued an Order Directing Further Conferences and Reports on November 15, 2012, after convening five regional conferences to obtain information about coordinating the natural gas and electricity markets.[1] Participants in the regional conferences addressed three sets of concerns: the ability of the gas and electric industries to share information, gas-electric scheduling differences and related issues, and reliability issues.[2]

The FERC provided guidance in its November 15 order about sharing information.[3] Although some conference participants were concerned that gas-electric communications may be inconsistent with the Commission's regulations on Standards of Conduct,[4] the Commission explained that "the Standards of Conduct apply to communications only within the same organization (i.e., between the affiliated entities of a single corporate family) and do not limit communications between unaffiliated natural gas pipelines and electric transmission system operators."[5] Additionally, the FERC explained that "the Standards of Conduct do not apply at all to Commission-approved [regional transmission operators (RTOs) or independent system operators (ISOs)]."[6] Lastly, the FERC explained that "the Standards of Conduct specifically authorize communications that may be necessary to address emergency conditions."[7]

Conference participants also raised concerns that the Natural Gas Act (NGA) and the Federal Power Act (FPA) prohibitions against "providing an undue preference for any customer or customer class" might impede gas-electric coordination.[8] In response, the FERC noted that "a significant amount of information is already shared across industries pursuant to existing market practices, including those implemented pursuant to Order No. 698."[9] The FERC directed its staff to hold a technical conference to identify whether additional guidance or potential regulatory changes should be considered to enhance gas-electric communications.[10]

The FERC also directed its staff to convene a technical conference about whether the gas and electric industry schedules "could be harmonized in order to

1. *Coordination Between Natural Gas and Electricity Markets*, 141 F.E.R.C. ¶ 61,125 at P 2 (2012).

2. *Id.* at PP 2-3.

3. *Id.* at PP 5-9.

4. 141 F.E.R.C. ¶ 61,125 at P 3; *see generally* 18 C.F.R. § 358.1(a)-(b) (2013).

5. *Id.* at P 6.

6. *Id.*; *see also* 18 C.F.R. § 358.1(c).

7. 141 F.E.R.C. ¶ 61,125 at P 7; *see also* 18 C.F.R. § 358.7(g)(2), (h)(2).

8. 141 F.E.R.C. ¶ 61,125 at P 8. Both the Federal Power Act (FPA) and the Natural Gas Act (NGA) prohibit undue discrimination or preference. 16 U.S.C. § 824d(b) (2012); 15 U.S.C. § 717c(b) (2012).

9. 141 F.E.R.C. ¶ 61,125 at P 8; Order No. 698, *Standards for Business Practices for Interstate Natural Gas Pipelines; Standards for Business Practices for Public Utilities*, F.E.R.C. STATS. & REGS. ¶ 31,251, 72 Fed. Reg. 38,757 (2007), *order on clarification and reh'g,* Order No. 698-A, 121 F.E.R.C. ¶ 61,264 (2007).

10. 141 F.E.R.C. ¶ 61,125 at P 5.

achieve . . . [more] efficient scheduling systems for both industries."[11] The gas day is well-defined as covering "a [twenty-four]-hour period beginning at 9:00 a.m. [c]entral clock time (CCT)," but "[t]here is no defined electric day."[12] Additionally, in order to obtain the best gas price, generators often need to nominate pipeline transportation service during the Timely Nomination Cycle at 11:30 a.m. CCT, which is before the generators get confirmation of their bids for sales into the electricity day-ahead market.[13] Also, some August 2012 conference participants were concerned about the Commission's "no bump" rule,[14] and participants "expressed a desire for more flexible pipeline capacity release" rules.[15]

The FERC directed its staff to report about gas and electric industry coordination activities quarterly during 2013 and 2014,[16] and the FERC directed RTOs and ISOs to appear at May and October 2013, meetings to describe winter/spring and summer/fall, respectively, gas-electric coordination issues.[17]

B. Market Transparency (RM13-1-000)

On November 15, 2012, the FERC issued a Notice of Inquiry (NOI) seeking comments on whether "quarterly reporting of every natural gas transaction within [its] NGA jurisdiction that entails physical delivery for the next day (i.e., next day gas) or for the next month (i.e., next month gas) would provide useful information for improving natural gas market transparency"[18] pursuant to the FERC's authority under section 23 of the NGA,[19] as enacted in

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11. *Id.* at P 11.

12. FED. ENERGY REGULATORY COMM'N, DEP'T OF ENERGY, STAFF REPORT ON GAS-ELECTRIC COORDINATION TECHNICAL CONFERENCES 30-31 (2012) [hereinafter STAFF REPORT], *available at* http://www.ferc.gov/legal/staff-reports/11-15-12-coordination.pdf.

13. *Id.* at 31-32.

14. *Id.* at 33. "[P]rimary and secondary nominations cannot bump already scheduled interruptible service during the final Intra-day 2 cycle, which is at 5 p.m. CCT." *Id. See generally* Order No. 587-G, *Standard for Business Practices of Interstate Natural Gas Pipelines*, F.E.R.C. STATS. & REGS. ¶ 31,062, at p. 30,670-72, 63 Fed. Reg. 20,072 (1998) (codified at 18 C.F.R. pt. 284 (2013)).

15. STAFF REPORT, *supra* note 12, at 35.

16. *Coordination Between Natural Gas and Electricity Markets*, 141 F.E.R.C. ¶ 61,125 at P 2 (2012).

17. *Id.* at P 12.

18. Notice of Inquiry, *Enhanced Natural Gas Market Transparency*, F.E.R.C. STATS. & REGS. ¶ 35,575 at P 1, 77 Fed. Reg. 69781 (2012) (hereinafter NOI).

19. 15 U.S.C. § 717t-2 (2012). Section 23 of the NGA states:

> [(a)](2) The Commission may prescribe such rules as the Commission determines necessary and appropriate to carry out the purposes of this section. The rules shall provide for the dissemination, on a timely basis, of information about the availability and prices of natural gas sold at wholesale and in interstate commerce to the Commission, State commissions, buyers and sellers of wholesale natural gas, and the public.
>
> [(a)](3) The Commission may—(A) obtain the information described in paragraph (2) from any market participant; and (B) rely on entities other than the Commission to receive and make public the information, subject to the disclosure rules in subsection (b) . . . .
>
> [(a)(4)(b)](1) Rules described in subsection (a)(2), if adopted, shall exempt from disclosure information the Commission determines would, if disclosed, be detrimental to the operation of an effective market or jeopardize system security.
>
> [(a)(4)(b)](2) In determining the information to be made available under this section and the time to make the information available, the Commission shall seek to ensure that consumers and competitive

the Energy Policy Act of 2005 (EPAct 2005).[20] The proposed reporting would supplement the current annual report of purchases and sales of natural gas in Form 552, as established in Order No. 704.[21]

The FERC expressed concern that currently available data "does not provide full market visibility or price transparency."[22] The NOI suggested that much of the data reported in Form 552 "is aggregated and does not provide transaction-specific details" and does not include the "details of off-exchange transactions of physical natural gas" or "information on price, date, location, or counterparty."[23] Further, Form 552 only reports "monthly transactions that are conducted during bid week for next calendar month delivery."[24] Moreover, the FERC indicated that although buyers and sellers report that transactions were "reported to an index publisher, they do not identify the index publisher."[25]

The NOI states that the FERC "is considering requiring market participants to report [additional] data elements for all jurisdictional transactions that entail physical delivery for next day gas . . . or . . . next month . . . [gas] in a standardized, electronic format and on a quarterly basis," including:

- name, address, and contact information of the trading company,
- name and location of its holding company,
- product traded (i.e., next day-delivery natural gas and next month-delivery natural gas),
- trade execution method (i.e., exchange or off-exchange, and name of exchange or broker) and settlement type (e.g., fixed or index priced),
- volume (in MMBtu) of natural gas traded,
- location (hub),
- price,
- date and time of the transaction,
- name of the counterparty, and
- the name(s) of the Index publisher(s) to which each transaction was reported.[26]

The FERC is not considering requiring reporting of sales of natural gas that have been excluded from its NGA section 1(b) jurisdiction, including sales that are not for resale in interstate commerce and "first sales" removed from NGA jurisdiction by the section 601(a)(1)(A) of the Natural Gas Policy Act of 1978

> markets are protected from the adverse effects of potential collusion or other anticompetitive behaviors that can be facilitated by untimely public disclosure of transaction-specific information.

Id.

20. Energy Policy Act of 2005, Pub. L. No. 109-5, § 316, 119 Stat. 594 (2005) (codified as amended 15 U.S.C. § 717t-2) [hereinafter EPAct 2005].

21. NOI, *supra* note 18, at P 11; *see also* Order No. 704, *Transparency Provisions of Section 23 of the Natural Gas Act*, F.E.R.C. STATS. & REGS. ¶ 31,260 at PP 2, 73 Fed. Reg. 1014 (2007), *order on reh'g and clarification*, Order No. 704-A, F.E.R.C. STATS. & REGS. ¶ 31,275, 73 Fed. Reg. 55,726 (2008), *order dismissing reh'g and clarification*, Order No. 704-B, 125 F.E.R.C. ¶ 61,302.

22. NOI, *supra* note 18, at P 11.

23. *Id.*

24. *Id.*

25. *Id.*

26. *Id.* at P 12.

(NGPA) as amended by the Wellhead Decontrol Act of 1989.[27] The NOI requested comments on specific data elements[28] such as which data should be made public,[29] whether the FERC should expand the reporting requirement to all natural gas wholesale transactions including those beyond its NGA jurisdiction,[30] and the burden of reporting on market participants.[31]

Comments in response to the NOI were filed in 2013 and are beyond the scope of this report.

II. RATES, TERMS, AND CONDITIONS OF SERVICE

A. Abandonment

1. *Trunkline Gas Co.*, 142 F.E.R.C. ¶ 61,133 (2013).

In the *Trunkline* rehearing order, the FERC denied requests for rehearing of Trunkline Gas Co., LLC's (Trunkline) requested abandonment that the FERC granted in its June 2012 order.[32] A coalition of producers[33] and Apache Corporation claimed that the FERC "failed to articulate any benefits to granting the proposals."[34] The Producer Coalition and Apache Corporation also argued that approving Trunkline's proposals would increase rates for services identical to those that shippers were previously receiving.[35] The FERC determined that while the Producer Coalition and Apache Corporation were largely not paying Trunkline for transportation services prior to abandonment, other Trunkline shippers were subsidizing that service.[36] The FERC dismissed the requests for rehearing, noting that when evaluating the public's interest, the FERC focuses not on the interest of a particular group or market segment, but rather on the "overall natural gas market."[37]

2. *Transwestern Pipeline Co.*, 140 F.E.R.C. ¶ 61,147 (2012).

The FERC approved Transwestern Pipeline Company, L.L.C.'s (Transwestern) application to abandon by sale to its affiliate an approximately

27. *Id.* at P 19; *see also* NOI, *supra* note 18, at P 19 & n.25. "The term 'first sale' is defined in section 2(21) of the Natural Gas Policy Act of 1978. Section 2(21) sets forth a general rule that all sales in the chain from the producer to the ultimate consumer are 'first sales' until the gas is purchased by an interstate pipeline, an intrastate pipeline, or a [local distribution company (LDC)]." *Id. See also* 15 U.S.C. § 3431(a)(1)(A) (2012).

28. NOI, *supra* note 18, at P 17.

29. *Id.* at P 18.

30. *Id.* at P 19.

31. *Id.* at P 20.

32. *Trunkline Gas Co.*, 142 F.E.R.C. ¶ 61,133 at PP 1, 3 (2013); *see also Trunkline Gas Co.*, 139 F.E.R.C. ¶ 61,239 (2012).

33. "The Producer Coalition includes: Century Exploration New Orleans, LLC (Century); Dynamic Offshore Resources, LLC; Energy XXI (Bermuda) Ltd.; Hilcorp Energy Company, Inc.; McMoRan Oil & Gas LLC; Pisces Energy LLC; and W&T Offshore, Inc. (hereinafter collectively referred to as the "Producer Coalition")." 142 F.E.R.C. ¶ 61,133 at P 2 n.2.

34. *Id.* at P 21.

35. *Id.* at P 25.

36. *Id.* at PP 28-29.

37. *Id.* at P 48.

59.5-mile long segment of a 24-inch diameter line that is part of Transwestern's West Texas Lateral.[38] Transwestern acknowledged that there were receipt and delivery points on the pipeline to be abandoned that were in use by current customers.[39] Transwestern stated that existing customers' points that were listed under a firm agreement or in use within the past twelve months would be relocated at no cost to a 30-inch diameter loop nearby.[40] Other points would be relocated at Transwestern's discretion.[41] Some customers protested the application, arguing that future gas production in the area of the proposed abandonment is expected to increase substantially and the facilities to be abandoned by Transwestern will be needed to transport future natural gas production.[42] The FERC noted that "[t]he results of Transwestern's open season demonstrate that there is presently little or no demand for additional firm service on Transwestern's West Texas Lateral."[43] The FERC stated that it "will not require a pipeline to retain unused transmission capacity in reserve awaiting the arrival of potential firm demand that may not materialize."[44]

3. *Panhandle Eastern Pipe Line Co.*, 141 F.E.R.C. ¶ 61,119 (2012).

The FERC approved Panhandle Eastern Pipe Line Company, LP's (Panhandle) application for authority to abandon its Adams Compressor Station.[45] Panhandle contended that there were no firm transportation contracts "associated with the facilities to be abandoned" and that the proposed abandonment would not affect the provision of any existing firm services.[46] Panhandle explained that the gas supplies associated with the Adams Compressor Station were "currently moved at no fee to pooling points downstream" and that the costs of that compression were subsidized by Panhandle's firm transportation customers.[47] Panhandle stated that if the proposed abandonment was approved, producers could "add compression upstream of the Adams Meter Station at their own cost" or re-route their gas to different receipt points on Panhandle's system.[48] DCP Midstream, LP (DCP), Anadarko Petroleum Corporation (APC), and Anadarko Energy Services Company (AESC) protested the proposed abandonment, arguing that the compression "provided by the Adams Compressor Station is necessary to deliver their gas into Panhandle's system."[49]

The FERC noted that there were no firm or interruptible contracts on Panhandle's system using the Adams Compressor Station facilities.[50] The FERC

38. *Transwestern Pipeline Co.*, 140 F.E.R.C. ¶ 61,147 at P 1 (2012).
39. *Id.* at P 7.
40. *Id.*
41. *Id.*
42. *Id.* at P 16.
43. *Id.* at P 17.
44. *Id.*
45. *Panhandle E. Pipe Line Co.*, 141 F.E.R.C. ¶ 61,119 at P 1 (2012).
46. *Id.* at P 13.
47. *Id.* at P 14.
48. *Id.* at P 15.
49. *Id.* at P 18.
50. *Id.* at P 21.

also found that "Panhandle's proposed abandonment will not in and of itself result in the shut in of production upstream of the facilities to be abandoned because there exist alternative means for that gas to reach the interstate grid."[51]

DCP, APC, and AESC also contended that Panhandle's proposal was "an attempt to use a section 7(b) application to reduce the operations and maintenance (O&M) costs embedded in its . . . rates without making an NGA section 4 filing" and contrary to a prior FERC decision.[52] The FERC distinguished the abandonment sought by Panhandle from the FERC's prior decision in *Northern Natural Gas Company (MOPS)* by noting that none of the protesting parties paid any rates associated with the facilities that Panhandle was seeking to abandon in the instant application.[53]

B. Acquisition Premium

1. *Missouri Interstate Gas, LLC*, 142 F.E.R.C. ¶ 61,195 (2013).

In *Missouri Interstate Gas, LLC (MoGas)*, the FERC issued an order in which it applied and clarified its policy regarding the circumstances under which a pipeline may include an acquisition premium in its rate base.[54] The order, in which the FERC reversed in part and affirmed in part the rulings of an administrative law judge's initial decision,[55] is the latest in a series of orders originating with the FERC's certificate orders authorizing the merger and operation in interstate commerce of predecessor entities to the current interstate pipeline, which had first converted oil pipeline facilities to natural gas service and then operated them in state-regulated natural gas transportation service.[56] In those orders, the FERC had permitted the applicant to include the full purchase price of various assets, including the acquisition premium, subject to being reexamined in a later rate proceeding.[57] The Missouri Public Service Commission (MoPSC) sought judicial review, and the D.C. Circuit ruled in *Missouri Pub. Serv. Comm'n v. FERC* that the FERC erred in deferring application of its usual "substantial benefits" test[58] to the acquired facilities and faulted the FERC's order for being inconsistent as to its rejection of certain cost elements in the predecessor pipelines' state regulated facilities.[59] Following the

51. *Id.* at P 22.

52. *Id.* at P 24 (citing *Northern Natural Gas Co. (MOPS)*, 135 F.E.R.C. ¶ 61,048 (2011)).

53. *Id.* at P 27.

54. *Missouri Interstate Gas, LLC (MoGas)*, 142 F.E.R.C. ¶ 61,195 at P 2 (2013).

55. *Missouri Interstate Gas, LLC (MoGas I.D.)*, 137 F.E.R.C. ¶ 63,014 (2011).

56. 142 F.E.R.C. ¶ 61,195 at P 2. The Commission summarizes the history and various findings of these earlier proceedings, *id.* at PP 3-6, and the evolution of the facilities and entities operating them, *id.* at PP 8-23.

57. *Missouri Interstate Gas, LLC*, 119 F.E.R.C. ¶ 61,074 (2007), *order on reh'g*, 122 F.E.R.C. ¶ 61,136 (2008), *reh'g denied*, 127 F.E.R.C. ¶ 61,011 (2009).

58. That test, set out in *Longhorn Pipeline Partners*, 73 F.E.R.C. ¶ 61,355, at p. 61,112 (1995), is summarized at *MoGas* and requires that the applicant meet a two-pronged test, that (1) the facilities in question were converted to a new use and (2) that the ratepayers obtained substantial benefits, in dollar terms, from the acquisition. 142 F.E.R.C. ¶ 61,195 at PP 44, 89-90. The Commission has also looked to whether the transaction was "arms-length." *Id.* at P 90.

59. Missouri Pub. Serv. Comm'n v. FERC, 601 F.3d 581 (D.C. Cir. 2010); 142 F.E.R.C. ¶ 61,195 at P 4.

court's decision, the FERC set the issue for hearing and ultimately the *MoGas* initial decision (*MoGas I.D.*) was issued.[60]

In *MoGas*, the FERC first addressed certain procedural issues[61] and then turned to substantive issues regarding its policy as to acquisition premiums. First, the FERC addressed when it is necessary to consider purchase prices as representing an acquisition premium; in this proceeding, the pipeline contended that the facilities in question were first "devoted to public service" when acquired by the interstate pipeline from its intrastate natural gas pipeline predecessors. The MoPSC had contended that the first commitment to public service occurred when the property was placed into oil pipeline service.[62] The *MoGas I.D.* had concluded that the "original cost" is the cost to the person first placing the facilities in public service, not the first placing them in natural gas service,[63] and the FERC affirmed that ruling as being consistent with the purpose of the policy and with its precedents, clarifying that merely because the facilities had changed in function, or had even been idled, did not change when they were committed first to public service.[64] That finding, however, required that the Commission then apply the "substantial benefits" test to determine whether the acquisition supports the pipeline's inclusion in the rate base of the acquisition premium in excess of original cost.[65] After resolving some complex and case-specific disputed issues concerning the nature and scope of the costs at issue,[66] the Commission found that the first prong of the test—whether the facilities were being committed to a new service—was uncontested, and affirmed that it had been met.[67] As to whether the pipeline had shown that the purchase provided substantial benefits to ratepayers, the FERC reversed the *MoGas I.D.* conclusion that the pipeline had failed to meet the test.[68] The FERC found that the entire pipeline purchased, not just a segment under a major river, should be included.[69] The FERC rejected the administrative law judge's finding that to meet the standard, the pipeline must show that the variance between the cost of constructing new facilities and the cost of buying the purchased facilities was "exorbitant," reaffirming that the test requires only that the benefits of the acquisition be "commensurate" with the acquisition costs.[70] The FERC further noted that in cases not involving affiliate transactions, it has consistently permitted recovery of the full acquisition costs when the purchase price is less

60. 601 F.3d at 588; 137 F.E.R.C. ¶ 63,014.

61. 142 F.E.R.C. ¶ 61,195 at PP 27-42. During the pendency of the various FERC proceedings, the Missouri Supreme Court held that the MoSPC had no authority to intervene in FERC proceedings. *Id.* at P 7. The pipeline had subsequently sought to reverse the *MoGas I.D.* as a matter of law for its reliance on evidence and pleadings submitted ultra vires and to exclude the State of Missouri as a substitute party for the MoPSC. *Id.* at PP 27, 37. The FERC denied both requests. *Id.* at P 41.

62. *Id.* at PP 44-48.

63. *Id.* at PP 49-51.

64. *Id.* at PP 59-64.

65. *Id.* at P 59.

66. *Id.* at PP 65-88.

67. *Id.* at P 95.

68. *Id.* at P 109.

69. *Id.*

70. *Id.* at P 111.

than the cost to construct comparable facilities.[71] The FERC also reversed the finding in the *MoGas I.D.* that although the buyer and seller were unaffiliated, certain accounting changes by the parties showed that the parties had a common economic interest; the FERC concluded that the accounting steps at issue had been appropriate and the transaction was nothing but an arms-length transaction between two non-affiliated parties.[72]

C. Capacity Allocation

1. *Rockies Express Pipeline LLC*, 141 F.E.R.C. ¶ 61,006 (2012).

In an October 1, 2012, rehearing order, the FERC addressed several remaining issues pertaining to Rockies Express Pipeline LLC's (Rockies Express) new backhaul-only service (BHS), namely, reconsideration of the FERC's condition that BHS shippers be granted secondary rights to make forward-haul nomination and, separately, concerns by a shipper that BHS would degrade existing firm shippers' rights.[73] The FERC in June 2011 approved Rockies Express' proposed BHS service that would provide a displacement-only service that would have a lower priority than primary firm nominations but higher than secondary firm.[74] According to Rockies Express, the lower priority and limited character of service would be commensurate with the reduced reservation rate for BHS, which was derived based upon 66% of the pipeline's firm reservation rates.[75] In its June 2011 Order the FERC approved the new service subject to a condition that Rockies Express allow BHS shippers to flow forward haul on a secondary basis.[76]

On rehearing, Rockies Express argued that because BHS was designed with lower reduced rates to reflect the limited character of service, it should not be required to offer BHS shippers with secondary forward-haul rights.[77] The pipeline argued that such a prohibition was supported by the FERC's previous orders, namely, with regard to a similar backhaul-only service on Tennessee Gas Pipeline Company.[78] The FERC agreed and removed the compliance filing obligation from the June 2011 order with respect to the requirement to allow BHS shippers to nominate forward-haul volumes on a secondary basis.[79]

On rehearing, the FERC also considered arguments by an existing Rockies Express firm shipper, which, in addition to adopting the pipeline's arguments as to BHS shippers' forward-haul secondary rights, also asserted that the FERC in its June 2011 order failed to support its finding that the new BHS service does not significantly degrade firm shippers' rights, including priority, capacity release, segmentation, and flexible points.[80] According to this shipper, the new

71. *Id.* at P 113.
72. *Id.* at PP 125-126.
73. *Rockies Express Pipeline LLC*, 141 F.E.R.C. ¶ 61,006 at PP 5-7 (2012).
74. *Rockies Express Pipeline LLC*, 135 F.E.R.C. ¶ 61,253 at PP 1-2 (2011).
75. 141 F.E.R.C. ¶ 61,006 at P 2.
76. *Id.* at P 4.
77. *Id.* at P 6.
78. *Id.*
79. *Id.* at P 8.
80. *Id.* at P 7.

BHS service would degrade the regulatory rights conveyed to shippers through the Commission's major open-access orders.[81] The FERC rejected these arguments, reasoning that firm shippers' rights remained intact despite the new service.[82] Indeed, the FERC noted that firm shippers shipping on their primary paths would continue to enjoy a higher priority of service than BHS.[83] The FERC also rejected the shipper's argument that the new service would create a competitive alternative to capacity release, particularly the use of secondary rights to obtain backhaul service.[84] The FERC noted the absence of any contractual or regulatory right limiting the pipeline's ability to modify its tariff to offer new service that may compete with released capacity.[85]

2. *Tennessee Gas Pipeline Co.*, 142 F.E.R.C. ¶ 61,033 (2013).

On January 17, 2013, the FERC issued an order establishing a technical conference to discuss the issues surrounding a proposal by Tennessee Gas Pipeline Company, L.L.C. (Tennessee Gas) to create two additional priority categories just below the highest priority given to firm primary receipt point to primary delivery point nominations.[86] Immediately below the primary-to-primary priority, Tennessee Gas proposed to grant priority to firm shippers nominating from secondary receipt to primary delivery points, so that they are scheduled ahead of firm shippers nominating from primary receipt to their secondary delivery points during periods of constraint on the pipeline.[87] Tennessee Gas's proposal was a modification to an initial proposal made in conjunction with its November 2010 general NGA section 4 rate case filing, which was subject to a previous technical conference and was later reserved for the Commission when the rate case participants reached a settlement on rates and other issues.[88]

In support of its latest proposal, Tennessee Gas argued that it addressed concerns regarding the possible degradation of service and was tailored to serve the needs of LDC and electric generation loads on its system.[89] Tennessee Gas's proposal drew a substantial response from a wide variety of customers, with LDCs and electric generators generally supportive, while producers and marketers filed in opposition based on undue discrimination concerns.[90] Based on the nature and degree of the protests, the FERC ordered its staff to conduct a technical conference to address the application of Tennessee Gas's proposal in light of the specific conditions on its system.[91]

81. *Id.*
82. *Id.* at P 9.
83. *Id.*
84. *Id.* at P 10.
85. *Id.*
86. *Tennessee Gas Pipeline Co*., 142 F.E.R.C. ¶ 61,033 at P 8 (2013).
87. *Id.*
88. *Id.* at PP 2, 4.
89. *Id.* at PP 9-10.
90. *Id.* at PP 15-22.
91. *Id.* at P 41.

3. *Great Lakes Gas Transmission LP*, 142 F.E.R.C. ¶ 61,160 (2013).

In February 2013, the FERC rejected Great Lakes Gas Transmission Limited Partnership's (Great Lakes) request for rehearing of the FERC's prior rejection of Great Lakes' proposal to allocate firm secondary out-of-path transportation on an economic basis.[92] In a January 2011 filing, the pipeline had proposed a scheme to allocate capacity within certain shipper classes.[93] Among firm secondary shippers (known as Category B shippers), the pipeline had proposed to allocate capacity based on the so-called "confirmed price" each shipper paid for the capacity, with shippers paying the higher price receiving the higher priority.[94] The confirmed price would include the reservation rate plus all applicable fees and surcharges computed at a 100% load factor.[95] Notably, the allocation scheme made no distinction between shippers paying the maximum recourse rate and those paying discounted rates.[96] For this reason, the FERC found that the allocation method was not just and reasonable.[97] Confirming its initial ruling in a July 2011 order,[98] the FERC explained, "any proposal to schedule firm secondary capacity according to absolute price must include a provision that all shippers paying the maximum rate applicable to their service will be scheduled ahead of any shipper paying a discounted rate."[99] The FERC, however, confirmed its policy allowing, generally, the allocation of capacity on an economic basis.[100] According to the FERC, "[b]y ensuring that all shippers paying the maximum rate in any zone are equal for scheduling purposes, the concerns about scheduling inequalities between short-haul and long-haul shippers are ameliorated."[101] The FERC found on rehearing that Great Lakes' proposal would not provide such an assurance and would allow a long-haul shipper paying a discount rate to be scheduled ahead of a short-haul shipper paying the maximum rate.[102]

D. Cost Trackers

On January 24, 2013, the FERC approved a contested settlement establishing a capital cost recovery mechanism (CCRM) for Columbia Gas Transmission, LLC (Columbia).[103] The CCRM was structured as an annually-updated rate surcharge, effective through 2018, that would recover the costs (up to a $300 million annual cap, subject to a 15% tolerance) of upgrading certain specifically-identified facilities on the aging Columbia system.[104] The CCRM

92. *Great Lakes Gas Transmission LP*, 142 F.E.R.C. ¶ 61,160 at P 1 (2013).
93. *Id.* at P 2.
94. *Id.*
95. *Id.* at P 2 n.4.
96. *Id.* at P 12.
97. *Id.*
98. *Great Lakes Gas Transmission LP*, 136 F.E.R.C. ¶ 61,070 (2011).
99. *Id.* at P 12.
100. *Id.* at P 11.
101. *Id.* at P 12.
102. *Id.*
103. *Columbia Gas Transmission, LLC*, 142 F.E.R.C. ¶ 61,062 at PP 1, 6 (2013).
104. *Id.* at P 7.

was coupled with annual base rate reductions and the payment of $50 million in refunds to firm shippers.[105] The settlement also included a number of features designed to provide Columbia with the incentive to perform the upgrades efficiently (e.g., specific identification of the facilities for which costs could be recovered in the CCRM, a billing determinant floor, caps on recoverable amounts, and shipper oversight).[106] Columbia also committed to $100 million in annual capital maintenance expenditures that would not be recouped through the CCRM.[107] The Maryland Public Service Commission opposed the settlement, citing the FERC's general policy against the use of rate trackers to recover costs incurred to comply with pipeline safety requirements.[108] Although acknowledging its policy disfavoring trackers for pipeline safety infrastructure spending, the FERC approved the settlement and CCRM.[109] The Commission found "that the settlement and the CCRM provide a reasonable means for Columbia to recover the substantial costs of addressing urgent public safety and reliability concerns, without undercutting Columbia's incentives to operate efficiently and to maximize service to the extent that previously proposed and rejected surcharges would have done."[110]

In Opinion No. 516-A, the FERC addressed requests for rehearing of its Opinion No. 516[111] and several other orders relating to a surcharge mechanism filed by Sea Robin Pipeline Company, LLC (Sea Robin) to recover hurricane damage repair costs.[112] Rejecting arguments for longer recovery periods, the FERC reaffirmed its previous finding that four years was a reasonable surcharge recovery period given Sea Robin's treatment of the plant replacement costs as an expense rather than a rate base item.[113] A four-year period, the FERC concluded, was similar to amortization periods it had approved for recovery of other one-time extraordinary expenses and would allow Sea Robin's hurricane repair costs to be removed from rates relatively quickly.[114] The FERC also affirmed its Opinion No. 516 ruling that Sea Robin could begin to accrue carrying costs as of the *filing* date of the hurricane surcharge rather than the *effective* date.[115] The FERC also closely analyzed a number of discounted service agreements and upheld its previous finding that Sea Robin was permitted to charge the hurricane surcharge under the terms of each of the discounted service agreements.[116] Finally, the FERC addressed rehearing requests concerning the mechanics of crediting insurance recoveries to the surcharge costs.[117]

105. *Id.* at P 6.
106. *Id.* at PP 23-25, 30.
107. *Id.* at P 8.
108. *Id.* at P 16.
109. *Id.* at P 31.
110. *Id.* at P 22.
111. Opinion No. 516, *Sea Robin Pipeline Co.*, 137 F.E.R.C. ¶ 61,201 (2011).
112. Opinion No. 516-A, *Sea Robin Pipeline Co.*, 143 F.E.R.C. ¶ 61,129 at P 1 (2013).
113. *Id.* at PP 35-59.
114. *Id.*
115. *Id.* at PP 73-80.
116. *Id.* at PP 87-213.
117. *Id.* at PP 227-29.

E. Discount Adjustments for Negotiated Rate Agreements

1. *East Tennessee Natural Gas, LLC*, 141 F.E.R.C. ¶ 61,023 (2012).

In *East Tennessee Natural Gas, LLC*, four interstate natural gas pipelines, East Tennessee Natural Gas, LLC, Ozark Gas Transmission, L.L.C., Saltville Gas Storage Company L.L.C., and Texas Eastern Transmission, LP (collectively, "Pipelines"), filed new tariff provisions to "streamline the procedures for passing through to a replacement shipper on a temporary basis the releasing shipper's negotiated charges by implementing online execution of negotiated rate agreements, thus eliminating the need for written execution."[118] The new procedures allow a replacement shipper to request the same negotiated usage or fuel charge as the releasing shipper, and the Pipelines will grant or deny requests based on whether the releasing and replacement shippers are similarly situated.[119] Several protesters objected to the timing for when the pipeline would determine whether a replacement shipper was "similarly situated."[120] The concern was that the releasing shipper would not know which proposal represented the highest value when the shipper had to select a winning bidder because the releasing shipper might not know whether the pipeline would qualify for the chosen replacement.[121] Protesters further argued that the Pipelines should clarify with specificity the elements they would use to determine if a replacement shipper was, in fact, similarly situated.[122] Relying on the general rule for pass through of negotiated usage and fuel charges that the FERC set forth in *Texas Eastern Transmission, LP* (*Texas Eastern*),[123] the Commission accepted the new proposals as just and reasonable, holding that interstate pipelines may pass through a discounted or negotiated usage or fuel charge to a replacement shipper on a case-by-case basis.[124] The Commission rejected objections to timing, finding that "the contracting process between the replacement shipper and the pipeline cannot take place until after the releasing shipper . . . [chooses] its replacement shipper and any bidding for the capacity release has been completed."[125]

2. *CenterPoint Energy—Mississippi River Transmission*, 140 F.E.R.C. ¶ 61,166 (2012).

In *CenterPoint Energy—Mississippi River Transmission*, Mississippi River Transmission (MRT) amended its tariff to "expand the circumstances in which . . . [it could] seek a discount-type adjustment to its recourse rates to reflect negotiated rate agreements."[126] The provision included specific factors that MRT had to show to demonstrate that any discount-type adjustment had no

118. *East Tenn. Natural Gas, LLC*, 141 F.E.R.C. ¶ 61,023 at PP 1-2 (2012).
119. *Id.* at P 3.
120. *Id.* at PP 5-6.
121. *Id.* at P 6.
122. *Id.*
123. *Texas E. Transmission, LP*, 129 F.E.R.C. ¶ 61,031 (2009).
124. 141 F.E.R.C. ¶ 61,023 at PP 11-12.
125. *Id.* at P 13.
126. *CenterPoint Energy—Miss. River Transmission*, 140 F.E.R.C. ¶ 61,166 at P 1 (2012).

adverse impact on recourse shippers.[127] Several shippers filed protests that argued, generally, that recourse rate shippers might be forced to subsidize shippers with discounted negotiated rate agreements.[128] The FERC accepted MRT's tariff language with the modification that MRT add the word "recovery" to the sentence "[m]aking another comparable showing that the negotiated rate discount contributes more fixed cost *recovery* to the system than could have been achieved without the discount."[129] The Commission stated it would consider any future request by MRT for discount rate treatment in a subsequent NGA section 4 general rate case, "including any discount adjustment for negotiated rates given to affiliates."[130]

F. Export

In *Sabine Pass Liquefaction, LLC*, the FERC denied the Sierra Club's request for rehearing and request for stay of the FERC's April 16 order[131] approving "Sabine Pass's proposal to construct and operate facilities that would enable the . . . [liquefaction and exportation of] up to 2.2 billion cubic feet of natural gas per day."[132] The Sierra Club argued that the FERC's decision was "arbitrary and capricious" in authorizing facilities for the liquefaction and export of domestically produced natural gas because it (1) failed to consider foreseeable indirect effects of inducing additional shale natural gas production, (2) failed to prepare an Environmental Impact Statement (EIS), and (3) improperly concluded that the proposed project was consistent with the public interest.[133] The FERC held that "induced" shale development and other associated impacts from the construction of an LNG terminal are too attenuated to be "reasonably foreseeable" as defined by the Council on Environmental Quality regulations implementing the National Environmental Policy Act and are thus not properly considered in the FERC's environmental assessment.[134] The FERC also found that it was not required to prepare an EIS because the proposed project would not have "significant" greenhouse gas emissions impacts.[135] The FERC disagreed with the Sierra Club and affirmed its earlier finding that the proposed project was not inconsistent with the public interest.[136] The FERC also dismissed as moot the Sierra Club's request for a stay.[137] The FERC went on to state that the Sierra Club had failed to demonstrate that the construction of the proposed project would cause the Sierra Club to suffer irreparable harm, and thus the FERC would have denied the stay request.[138]

127. *Id.* at P 2.
128. *Id.* at PP 3-12.
129. *Id.* at P 15.
130. *Id.* at P 14.
131. *Sabine Pass Liquefaction, LLC*, 139 F.E.R.C. ¶ 61,039 (2012).
132. *Sabine Pass Liquefaction, LLC*, 140 F.E.R.C. ¶ 61,076 at PP 1-2 (2012).
133. *Id.* at P 7.
134. *Id.* at P 6.
135. *Id.* at P 24.
136. *Id.* at P 30.
137. *Id.* at P 33.
138. *Id.* at P 35.

G. Fuel

1. *El Paso Natural Gas Co.*, 143 F.E.R.C. ¶ 61,042 (2013).

El Paso Natural Gas Company, L.L.C. (El Paso) filed a request for rehearing of an October 12, 2012 order[139] granting El Paso a certificate of public convenience and necessity pursuant to section 7(c) of the Natural Gas Act (NGA) and a companion certificate pursuant to section 3 of the NGA to amend and reissue El Paso's existing Presidential Permits.[140]

Although the order "authorized El Paso to increase capacity on its Willcox Lateral by reconfiguring the Willcox Compressor Station" and "amended El Paso's existing Presidential Permits to increase the export capacity at border crossing facilities served through the Willcox Lateral," the order "denied El Paso's request for predetermination of rolled-in rate treatment for the expansion project and its proposal to apply an incremental fuel charge to existing firm customers' overrun or alternate firm service and to interruptible transportation (IT) shippers."[141]

El Paso sought rehearing on the FERC's determination regarding the incremental fuel charge to IT shippers.[142] El Paso claimed that the FERC's rejection of its proposal resulted from "a misunderstanding that IT service using the expansion facilities is identical to the IT services under the existing Willcox Lateral facilities."[143] El Paso explained that it sought to assess the incremental fuel charge to the Douglas and El Fresnal Meter Stations.[144] In the October 2012 order, the FERC held that the "currently-effective rates and contracts for overrun and alternate firm service do not have a fuel charge, and El Paso cannot change the existing approved Willcox Lateral fuel rate applicable to existing customers and capacity in an NGA section 7 proceeding."[145] The FERC disagreed with El Paso's claims that "the IT service using the Willcox Lateral Expansion facilities is separate and distinct from IT service using the existing Willcox Lateral facilities."[146] "El Paso did not draw any distinctions between the IT service using the El Fresno and Douglas Meter Stations and [the] IT service using the Willmex Meter Station for purposes of applying an incremental . . . charge," and El Paso stated that both new firm expansion customers and Willcox Lateral customers will derive a benefit.[147] The FERC noted that "Commission policy generally does not allow a separate IT rate for additional capacity related to new compression projects on an integrated system like the Willcox Lateral."[148] Further, the FERC noted that "[n]o pressure regulator is currently located or will be located on the Willcox Lateral facilities" meaning that "all interruptible service on the Willcox Lateral will be using the compression-based expansion

139. *El Paso Natural Gas Co.*, 141 F.E.R.C. ¶ 61,026 (2012).
140. *El Paso Natural Gas Co.*, 143 F.E.R.C. ¶ 61,042 at P 1 (2013).
141. *Id.*
142. *Id.*
143. *Id.* at P 8.
144. *Id.*
145. *Id.* at P 9.
146. *Id.* at P 12.
147. *Id.* at P 13.
148. *Id.* at P 11.

facilities" and "will incur fuel costs regardless of . . . [point of delivery] or whether the interruptible service needs compression."[149]

2. *Ruby Pipeline, L.L.C.*, 142 F.E.R.C. ¶ 61,104 (2013).

On October 30, 2012, Ruby Pipeline, L.L.C. (Ruby) filed tariff records to comply with the Commission's September 28, 2012, order,[150] which "required Ruby to either revise the cash-out mechanism in its fuel, lost and unaccounted for (FL&U) tracker or show cause why it should not be required to do so."[151] Ruby claimed "that the September 28 [o]rder misinterprets its tariff," and "its tariff does not cash out over-recoveries at the "lowest of the index prices described in section 10.3 of the [general terms and conditions (GT&C)]."[152] In contrast, Ruby asserts that "over-retained quantities of FL&U are cashed-out using an index price at its eastern terminus at Kern River Transmission Company, Wyoming (Kern River-Opal)."[153]

The FERC rejected Ruby's proposal, holding that it failed to demonstrate that its proposed tariff modification was just and reasonable or that the language was consistent with the September 28 order.[154] The Commission noted that Ruby should not be able to profit on its over collection of fuel quantities, and Ruby must provide reasonable monetary equivalent value of the over-recovered gas such as the sale price Ruby would receive if it sold the gas.[155] Ruby proposed to calculate the cash-out compensation based on the value of gas at lower priced Kern River-Opal; however, the Commission found that "Ruby appears to make nearly all of its operational sales at" higher priced PG&E-Malin.[156] The Commission noted that it is not just and reasonable for Ruby to turn cash-outs for over-collections into a profit center.[157]

3. *Texas Eastern Transmission, LP*, 141 F.E.R.C. ¶ 61,172 (2012).

Texas Eastern Transmission, LP (Texas Eastern) filed proposed revisions to the Applicable Shrinkage Adjustment (ASA) Percentages and Surcharges of its tariff.[158] Under the current tariff, Texas Eastern is required to "file annually to revise both its ASA Percentages and its ASA Surcharge."[159] "[I]n calculating these percentages, it uses [an] average of the last three years," and in calculating the ASA Surcharges, it uses "the net monetary balance recorded in the Shrinkage Deferred Account as of August 31" for each year.[160] Texas Eastern proposed to revise its calculation with respect to certain contract paths that have changed

149. *Id.* at P 12.
150. *Ruby Pipeline, L.L.C.*, 140 F.E.R.C. ¶ 61,256 (2012).
151. *Ruby Pipeline, L.L.C.*, 142 F.E.R.C. ¶ 61,104 at P 1 (2013).
152. *Id.* at P 5.
153. *Id.*
154. *Id.* at P 14.
155. *Id.*
156. *Id.* at P 15.
157. *Id.*
158. *Texas E. Transmission, LP*, 141 F.E.R.C. ¶ 61,172 at P 1 (2012).
159. *Id.* at P 2.
160. *Id.*

from historical backhauls to forward hauls.[161] Texas Eastern asserts that because "new supply sources have emerged outside the Access Area, . . . a material shift in customer sourcing patterns" has occurred, and until this year, the change in flows was not significant enough to warrant a change in Texas Eastern's fuel rate design.[162]

Several parties protested the filing on the basis that Texas Eastern did not demonstrate that "its proposal to assess fuel for contract paths that have historically been characterized as backhaul transportation is just and reasonable."[163] The FERC agreed with the protesting parties that Texas Eastern had not shown that its proposed tariff records were just and reasonable.[164] Furthermore, the FERC found potential "operational and technical issues" that should be addressed at a technical conference.[165]

H. Gas-Electric Coordination

1. *ISO New England Inc.*, 142 F.E.R.C. ¶ 61,058 (2013).

ISO New England Inc. (ISO-NE) filed proposed revisions to its Information Policy, providing a protocol for sharing, under a proposed Non-Disclosure Agreement (NDA), confidential information regarding specific New England gas-fired generators with operating personnel of interstate gas pipelines serving those generators.[166] The filing's asserted purpose was to increase communication and coordination between ISO-NE and the gas industry to help enhance electric reliability, particularly during the winter season.[167] The filing was protested by generators claiming that their confidential, proprietary information was inadequately protected by the proposed NDA and that they lacked sufficient recourse in the event of a breach as the proposed agreement disclaimed third-party beneficiary rights.[168]

In its initial order on the filing, issued December 7, 2012, the FERC accepted and suspended ISO-NE's filing and referred the matter to a settlement judge.[169] Settlement efforts were unsuccessful, but ISO-NE subsequently filed proposed modifications intended to provide greater confidentiality protections as well as conform its protocols more closely to those used by other ISOs and RTOs.[170] ISO-NE also sought clarifications, including confirmation that the anticipated information sharing between pipelines and ISO-NE would not violate the *Standards of Conduct for Transmission Providers* regulations.[171]

The Commission responded to the clarification requests, noting that as a general matter, the *Standards of Conduct* pertain to communications with

161. *Id.* at P 3.
162. *Id.* at P 4.
163. *Id.* at P 8.
164. *Id.* at P 13.
165. *Id.* at P 14.
166. *ISO New England Inc.*, 142 F.E.R.C. ¶ 61,058 at PP 3, 6 (2013).
167. *Id.* at P 4.
168. *Id.* at PP 7-8.
169. *Id.* at P 10.
170. *Id.* at PP 11-13.
171. *Id.* at P 21.

affiliates that engage in marketing functions and do not apply to Commission-approved ISOs and RTOs.[172] But the Commission refused to be more specific, noting that its general guidance may not be applicable to particular facts and circumstances and urging market participants to seek informal or formal guidance regarding specific proposed transactions, practices, or situations.[173] ISO-NE's proposed tariff modifications were accepted on an interim basis, to be effective through April 30, 2013, with some additional limitations imposed on the information sharing process.[174]

2. *Trailblazer Pipeline Co.*, 141 F.E.R.C. ¶ 61,175 (2012) and 143 F.E.R.C. ¶ 61,084 (2013).

On October 31, 2012, Trailblazer Pipeline Company, LLC (Trailblazer) proposed to establish a new Firm Transmission Balancing Service (FTB) in its FERC Gas Tariff.[175] Under this new service, Trailblazer proposed to give shippers at least two additional nomination cycles during the gas day.[176] In order to provide this additional flexibility, and given that it lacks its own system storage, Trailblazer proposed to reserve the FTB shippers' Maximum Daily Quantity (MDQ) such that the capacity would not be available to other shippers for secondary or IT service at any time.[177] FTB rates were proposed to be the same as firm transportation service (FTS) so long as nominations were within the shipper's Maximum Hourly Quantity (MHQ) of 1/24th of the MDQ, and nominations in excess of MHQ would be treated as interruptible and, if scheduled, subject to an Enhanced Hourly Delivery Charge.[178]

Trailblazer's proposed new FTB service was widely protested, and the Commission scheduled a technical conference.[179] During this phase of the proceeding, Trailblazer agreed to some modifications to its original proposal.[180] In its Order Following Technical Conference, the Commission largely approved Trailblazer's revised proposal, including its proposed rates, but ordered the pipeline to remove the provision that would have withheld FTB shippers' capacity from the market if unnominated by FTB shippers as unjustified and inconsistent with its policy.[181]

3. *Florida Gas Transmission Co.*, 141 F.E.R.C. ¶ 61,161 (2012).

In this proceeding, Florida Gas Transmission Co., LLC (FGT) filed to add an additional intraday nomination change opportunity for certain services and at specified "qualified" points of receipt and delivery (where the point operator has

172. *Id.* at PP 22, 24.
173. *Id.* at P 25.
174. *Id.* at P 26.
175. *Trailblazer Pipeline Co.*, 141 F.E.R.C. ¶ 61,175 at P 1 (2012).
176. *Id.* at P 3.
177. *Id.* at PP 4-5.
178. *Id.* at P 4.
179. *Id.* at P 13.
180. *Trailblazer Pipeline Co.*, 143 F.E.R.C. ¶ 61,084 at P 10 (2013).
181. *Id.* at PP 23-24.

agreed to accept automatic scheduling changes).[182] The proposal was supported by some electric generation shippers as increasing operational flexibility but protested by a municipal group concerned about cost subsidization by shippers not needing this additional flexibility.[183] The FERC approved the proposal, dismissing the concerns about costs and distinguishing the additional nomination proposal from other proposals in which new services were at issue.[184]

I. Gas Quality & Interchangeability

1. *Gas Transmission Northwest LLC*, 143 F.E.R.C. ¶ 61,033.

In this proceeding, Gas Transmission Northwest LLC (GTN) filed a petition for declaratory order regarding the interpretation of the phrase "commercially free" of objectionable substances as used in GTN's tariff.[185] Section 6.3(1)(b)(1) of GTN's tariff provides that the gas shipper delivers to GTN for transport and that GTN then transports for such a shipper "commercially free from . . . objectionable substances . . . which may interfere with its commercial utilization."[186] PacifiCorp brought suit for negligence and breach of contract based on GTN delivering gas with "compressor oil in excess of that permitted under GTN's tariff."[187] GTN requested that the Commission declare "commercially free" to mean that the natural gas supplied to GTN may contain substances "in quantities that do not interfere with the ordinary commercial utilization of natural gas."[188]

The Commission noted that to be commercially free of objectionable substances, the gas must not be "(1) injurious to pipelines, (2) interfere with the transmission of gas through pipelines, or (3) interfere with the commercial use of the gas."[189] In this case, the Commission found that the term "commercially free from . . . objectionable substances . . . which may interfere with its commercial utilization means that the natural gas supplied by GTN may contain substances . . . so long as" the quantity of the substances does "not interfere with the commercial utilization of the natural gas in the ordinary course of business."[190]

J. Incremental Pricing

1. *Equitrans, L.P.*, 143 F.E.R.C. ¶ 61,108 (2013).

The FERC denied the request for rehearing filed by Equitrans, L.P. (Equitrans), which had taken issue with certain initial rate determinations made in the NGA section 7(c) certificate order approving Equitrans' Sunrise Project.[191]

182. *Florida Gas Transmission Co.*, 141 F.E.R.C. ¶ 61,161 at PP 1, 4 (2012).
183. *Id.* at PP 7, 9-10.
184. *Id.* at PP 14-19.
185. *Gas Transmission Nw. LLC*, 143 F.E.R.C. ¶ 61,033 at P 1 (2013).
186. *Id*. at P 10.
187. *Id*. at P 3.
188. *Id*. at P 11.
189. *Id.* at P 17.
190. *Id*. at P 23.
191. *Equitrans, L.P.*, 143 F.E.R.C. ¶ 61,108 at PP 1-2 (2013).

This expansion project involves the construction of facilities to create incremental capacity to transport Marcellus Shale gas to mid-Atlantic and east coast markets.[192] The new Sunrise facilities and capacity are integrated with Equitrans' existing mainline system, and while the Sunrise Project service was certificated with incremental initial rates for firm service, the pipeline's proposed "access charge" for incumbent firm shippers to use the Sunrise facilities on a secondary basis, as well as the proposed incremental IT rate for service on the Sunrise facilities, were rejected.[193]

On rehearing, the Commission defended its rejection of the Sunrise access charge, stating that it was consistent with the certificate policy statement requirement that the new shippers and the pipeline must be prepared to financially support an expansion project.[194] The Commission concluded that because the Sunrise Project is integrated into Equitrans' single-zone system, incumbent shippers should have the right to access any point on the system on a secondary basis without having to incur any additional costs.[195] Similarly, the Commission adhered to its general policy disfavoring separate IT rates for new projects.[196] Because of the integrated nature of the Sunrise and mainline systems, the Commission found that Equitrans could not appropriately identify and account for shippers' use of the new facilities, which would be necessary to justify a separate IT rate.[197]

2. *Eastern Shore Natural Gas Co.*, 146 F.E.R.C. ¶ 61,124 (2013).

In this Order Issuing Certificate, the Commission approved Eastern Shore Natural Gas Company's (Eastern Shore) Greenspring Expansion Project, which involves new facilities to support incremental firm service.[198] Because the new service spanned more than one rate zone (with successively higher rates in each zone), Eastern Shore proposed, as an alternative to a stand-alone cost-based incremental recourse rate, incremental rates consisting of an "adder" to the current zone-based transportation services.[199] The adder was based on the revenue deficiency that would have resulted had the incremental shippers been subject to Eastern Shore's existing rates.[200] The FERC found this approach generally acceptable but required Eastern Shore to recalculate its adder to avoid a small over-collection the pipeline had attributed to rounding.[201]

192. *Id.* at P 1.
193. *Id.* at P 8.
194. *Id.* at P 19.
195. *Id.* at P 26.
196. *Id.* at P 34.
197. *Id.* at P 35.
198. *Eastern Shore Natural Gas Co.*, 146 F.E.R.C. ¶ 61,124 at PP 1-2 (2013).
199. *Id.* at PP 22-23.
200. *Id.* at PP 21, 23.
201. *Id.* at PP 30-31.

K. Jurisdiction

1. *Atlas Pipeline Mid-Continent WestTex, LLC*, 143 F.E.R.C. ¶ 61,043 (2013).

The FERC denied a request for rehearing from Atlas Pipeline Mid-Continent WestTex, LLC (Atlas) and Pioneer Natural Resources USA, Inc. (Pioneer) which filed for an NGA section 7(c) certificate to construct and operate a 10.2-mile, 16-inch diameter pipeline in Texas called the Driver Residue Pipeline.[202] The pipeline was to transport natural gas from a non-jurisdictional processing plant "to interconnections with three gas transmission pipeline systems, including an interstate pipeline and two intrastate pipelines."[203] The pipeline did not qualify as a non-jurisdictional "stub line" because its length exceeded the five-mile limit that the Commission imposes for such designation.[204] Accordingly, Atlas and Pioneer requested that the Commission issue a "limited jurisdiction" certificate with "general waivers of the Commission's tariff and rate regulations."[205] In *Atlas I*, the Commission granted the majority of the request but did not grant waiver of the filing requirement for assessing annual charges.[206] On rehearing, the Commission rejected arguments that the project should be exempt from the annual charge assessment.[207] The Commission clarified that the "limited jurisdiction" exemption was "adopted to exempt companies such, as Hinshaw pipelines and local distribution companies, that use their non-jurisdictional facilities to provide limited services in interstate commerce."[208] The Commission stated that its policy going forward would be to:

> deny requests by otherwise non-jurisdictional applicants seeking certificates to construct and/or operate jurisdictional facilities, including residue pipelines from the outlets of non-jurisdictional processing plants, for waivers to exempt them from the Commission's annual charge assessments and related filing requirements, if the certificated facilities' transportation volumes meet the thresholds for assessing annual charges.[209]

2. *Chipeta Processing LLC*, 140 F.E.R.C. ¶ 61,041 (2012).

In *Chipeta Processing LLC*, the FERC considered the jurisdictional status of a natural gas processing complex that included two processing plants, Chipeta Plant and Natural Buttes Plant, and a pipeline that interconnected the two plants.[210] The complex would operate in two modes: (1) as a processing plant that receives gas from upstream gathering systems and (2) as a processing plant that receives gas from a jurisdictional pipeline and delivers processed gas to

202. *Atlas Pipeline Mid-Continent WestTex, LLC (Atlas I)*, 140 F.E.R.C. ¶ 62,238 (2012), *reh'g denied*, *Atlas II*, 143 F.E.R.C. ¶ 61,043 (2013).

203. 143 F.E.R.C. ¶ 61,043 at P 3.

204. *Id.* at P 5.

205. *Id.*

206. 140 F.E.R.C. ¶ 62,238, at p. 64,783.

207. 143 F.E.R.C. ¶ 61,043 at PP 8-10.

208. *Id.* at P 11.

209. *Id.* at P 13.

210. *Chipeta Processing LLC*, 140 F.E.R.C. ¶ 61,041 (2012).

another jurisdictional pipeline or to pipelines connected to the Chipeta Plant's header.[211] The Commission found that the pipeline between the plants was a nonjurisdictional stub line because it was "less than five miles long" and was an "incidental extension" of the complex.[212] In addition, when the Chipeta plant was operating in the second mode, the Commission determined that it would be a "straddle plant."[213] A straddle plant "receives gas from an interstate pipeline, processes the gas by removing the liquids for their economic value, and returns the gas to the interstate pipeline or delivers it to another pipeline for continued transportation."[214] Such plants are non-jurisdictional.[215]

3. *Gas Co.*, 142 F.E.R.C. ¶ 61,036 (2013).

In *Gas Co.*, the FERC dismissed an NGA section 3 request for "authorization to operate facilities to receive and vaporize domestic liquefied natural gas (LNG) transported from the continental [United States], for distribution to end use customers in Hawaii."[216] The Commission noted that NGA section 3 traditionally has been triggered "when gas is transported between the [United States] and another country, not when gas is transported within the [United States]."[217] The Commission, however, did not rely on this distinction for its holding.[218] Rather, the Commission focused on the method by which the natural gas was being shipped and revaporized and found that the "existing pier facilities which [would] receive, load, and unload the vessels carrying [International Shipping Organization (ISO)] containers of LNG [would be] the same facilities currently receiving, loading, and unloading containers filled with other products."[219] Accordingly, the Commission held that such facilities were not "natural gas facilities" as defined in NGA section 2(11).[220] The Commission further held that the facilities used to revaporize the LNG were exempt from the Commission jurisdiction because The Gas Company qualified either as an exempt local distribution company or a Hinshaw pipeline.[221]

L. Liquids

In *Questar Pipeline Co.* (*2012 Order*), the Commission denied requests for rehearing and clarification of its earlier order granting Questar Pipeline Company (Questar) authorization to construct and modify facilities to permit shippers to transport higher BTU natural gas.[222] In *2012 Order*, the FERC denied protests by two parties, who on rehearing asserted that the FERC had

211. *Id.* at P 14.
212. *Id.* at P 17.
213. *Id.* at P 18.
214. *Id.*
215. *Id.*
216. *Gas Co.*, 142 F.E.R.C. ¶ 61,036 at P 1 (2013).
217. *Id.* at P 9.
218. *Id.* at P 11.
219. *Id.* at PP 13-14.
220. *Id.* at PP 10-11.
221. *Id.* at P 12.
222. *Questar Pipeline Co.*, 140 F.E.R.C. ¶ 61,040 (2012) [hereinafter *2012 Order*], *reh'g denied*, 142 F.E.R.C. ¶ 61,127 at P 1 (2013).

erred in failing to find that the project would adversely affect the natural gas that they transport on or supply to the Questar system, that the pipeline had not made efforts to eliminate or minimize adverse impacts, that the scope of an earlier, related project had not been fully disclosed, and that the project complied with certain other regulations.[223] The FERC examined the rehearing requests and reaffirmed its prior holdings in favor of granting the certificate.[224] The FERC rejected, inter alia, the petitioners' concern that transportation upstream of the pipeline's compressor station was inherently less reliable than transportation through a compressor station[225] as well as contentions that the new facilities would unfairly compete with the petitioners' facilities.[226] In addition, the Commission declined to grant a request for clarification regarding maximum allowable operating pressure (MAOP) for a compressor station, finding that the requested MAOP stated in the application did not restrict future changed pressures at higher levels[227] and that the tariff adequately informed the shippers of their pressure obligations.[228]

M. Market-Based Rates

On November 2, 2012, the D.C. Circuit Court of Appeals issued its decision, *Northern Natural Gas Co. v. FERC*, affirming FERC Orders[229] in 2010 and 2011 (*Orders*) denying Northern Natural's request to extend its market-based rate authority to new contracts following the expiration of the initial contracts granted in a 2006 order[230] applying section 4(f) of the NGA, but granted the pipeline's request to apply market-based rates to contracts in the event of bankruptcy, default, or turn-back during the twenty-year terms of the contracts.[231] The court noted that in the *Orders*, the FERC had relied upon the purpose of section 4(f), which is to make market-based rates available as an incentive for newly-constructed storage capacity as an incentive to its construction.[232] The Commission had held in the *Orders* that the market-based rate authority had only been granted for the initial contracts for storage, not contracts subsequent to the initial contracts, and that market-based rate authority for new contracts on already-constructed storage assets were not within the scope of section 4(f), which requires that the authority be "necessary to encourage the construction of the storage capacity."[233] In its decision, the court concluded that the FERC's holding and rationale were reasonable in light of the purpose of the statute, which is to incent the construction of new facilities, rather

223. 142 F.E.R.C. ¶ 61,127 at PP 3-4.

224. *Id.* at PP 7-26.

225. *Id.* at P 9.

226. *Id.* at P 17.

227. *Id.* at PP 29-30.

228. *Id.* at P 31.

229. *Northern Natural Gas Co.*, 133 F.E.R.C. ¶ 61,210 (2010), *reh'g denied*, 135 F.E.R.C. ¶ 61,085 (2011).

230. *Northern Natural Gas Co.*, 117 F.E.R.C. ¶ 61,191 (2006).

231. Northern Natural Gas Co. v. FERC, 700 F.3d 11, 13-14 (D.C. Cir. 2012).

232. *Id.* at 14.

233. *Id.* at 14; *see also* 135 F.E.R.C. ¶ 61,085 at PP 10, 12-13.

than apply to existing facilities.[234] The court noted that the second element of the FERC's holding—allowing market-based rate authority to contracts subject to bankruptcy, default, or turnback during their twenty-year term—was consistent with this rationale because permitting such rates for replacement contracts within the original terms "makes sense."[235] The pipeline also argued in the alternative that the policy in the *Orders* should be extended only on a prospective basis to its expansion because of its detrimental reliance on certain language suggesting potential market-based rights in the future.[236] The court dismissed this argument, finding that the language in question was only dicta, and further that it did not state that market-based rates would be available, noting as well that there was no evidence that the construction undertaken after this language was issued was in fact made in reliance on the language.[237] The court concluded that the pipeline had failed to show that the alleged action was both in reliance and was reasonable.[238]

The scope and applicability of section 4(f) arose in another project of Northern Natural Gas Company, a 2011 expansion project.[239] In the 2011 order,[240] the FERC denied a request for market-based rate authority for the proposed new capacity, finding that the proposed facilities (firming up of interruptible to firm storage) did not involve new facilities within the meaning of the statute and that Northern Natural Gas Company had not shown adequately that the market-based authority was needed to support initiation of the project.[241] The pipeline sought rehearing, and on April 18, 2013, the FERC denied rehearing.[242] First, the Commission affirmed its finding that "new" storage capacity required new facilities, that the proposed new service did not increase the certificated maximum capacity of the storage fields, and that the additional base gas needed to achieve the firmed up level of service had been contemplated in the original certificate orders.[243] Regarding the grounds needed to show that market-based rates are necessary to incent construction of new capacity, the Commission characterized the pipeline's arguments as requiring it to accept the assertions of the pipeline that market-based rates were necessary; in response, the FERC noted that the statute does not require issuance of market-based rates even when the capacity is needed and that in its implementing regulations, the FERC had not adopted a presumption that new storage would not be built without the market-based authority.[244] The FERC also rejected the argument that this order on rehearing was inconsistent with its earlier grant of authority to a 2008 expansion by the same pipeline that had recognized the cost and risk of new base gas as a factor supporting market-based rates, finding that the pipeline

234. 700 F.3d at 14.
235. *Id*. at 14.
236. *Id.* at 15-16.
237. *Id.* at 16.
238. *Id.*
239. *Northern Natural Gas Co.*, 134 F.E.R.C. ¶ 61,247 at PP 1, 19-37 (2011).
240. 134 F.E.R.C. ¶ 61,247.
241. *Id.* at PP 21-24.
242. *Northern Natural Gas Co*., 143 F.E.R.C. ¶ 61,044 (2013).
243. *Id.* at P 7.
244. *Id.* at PP 8-9.

has significant information as to likely field operations, that gas price volatility had lessened, and that the presence of aquifer storage characteristics did not compel a different conclusion.[245] The FERC noted that the 2008 expansion was larger and had greater uncertainties.[246] The FERC also affirmed its earlier statement that the absence of a cost-based reserve price in the open season raised concerns as to the need for the project and noted that although such a price was not required in the regulations or in the first storage project application made by the pipeline after the 2005 amendment to the NGA, the context has changed since the earlier order.[247]

N. New Services

1. *National Fuel Gas Supply Corp.*, 143 F.E.R.C. ¶ 61,155 (2013).

The FERC rejected National Fuel Gas Supply Corporation's (National Fuel) proposed Market Pooling Point Aggregation Service (MPPAS) because National Fuel's proposed effective date was at some indefinite date in the future—contrary to section 154.207 of FERC's regulations—but otherwise found the MPPAS proposal to be generally reasonable.[248] National Fuel's proposed MPPAS service included the establishment of various market pooling points (MPP).[249] National Fuel proposed to "transport gas to and from the MPPs" under various existing rate schedules, make each MPP an eligible nomination point for receipt and delivery under those rate schedules, and allow "Pool Aggregators" (i.e., parties with an MPPAS service agreement) to "nominate to transfer the quantities" they aggregate at the MPP "into the MPP of another shipper at the same MPP."[250]

Subject to certain modifications, the FERC determined that National Fuel could file identical tariff records once its filing satisfies section 154.207.[251] Specifically, the FERC noted that if National Fuel files identical tariff records in the future, it must amend its proposal so that its MPPAS usage charge "be determined on a per transaction basis, and not volumetrically, as proposed by National Fuel."[252]

2. *Tennessee Gas Pipeline Co.*, 143 F.E.R.C. ¶ 61,128 (2013).

The FERC accepted, subject to certain conditions, Tennessee Gas Pipeline Company, L.L.C.'s (Tennessee) pro forma tariff records to offer a "new rich gas transportation service on a limited portion of its existing system so that shippers can move supplies from the Utica Shale to downstream markets."[253] Tennessee stated that it could not transport rich gas from the Utica Shale on its current

245. *Id.* at PP 10-13.
246. *Id.* at PP 13-14.
247. *Id.* at PP 15-18.
248. *National Fuel Gas Supply Corp.*, 143 F.E.R.C. ¶ 61,155 at PP 1, 3 (2013).
249. *Id.* at P 5.
250. *Id.*
251. *Id.* at P 15.
252. *Id.* at P 20.
253. *Tennessee Gas Pipeline Co.*, 143 F.E.R.C. ¶ 61,128 at PP 1-2 (2013).

system because it "does not comply with the gas quality specifications" of its tariff.[254] However, Tennessee proposed to dedicate one of four parallel mainline pipes within the Utica Shale production area to transport Utica Shale gas.[255]

The FERC determined that it would accept Tennessee's proposal because such a service "will increase shipper flexibility and provide increased access to Utica Shale gas supplies without unduly affecting existing firm shippers."[256] Specifically, the FERC stated that firm shippers will continue to have "access to the same secondary receipt and delivery points as they now do, and will have the same hourly and daily flexibility" that Tennessee currently provides.[257] Going forward, Tennessee can "provide its new rich gas transportation service under its existing Rate Schedules FT-A and IT" but must do so on a not unduly discriminatory basis and cannot deny a third-party request for interconnection on the pipeline dedicated to provide the new service.[258] In order to begin to provide actual service, Tennessee must submit its actual, conforming tariff records sixty days prior to the in-service date.[259]

3. *Trailblazer Pipeline Co.*, 143 F.E.R.C. ¶ 61,084 (2013).

The FERC accepted, subject to certain conditions, Trailblazer Pipeline Company LLC's (Trailblazer) proposal to establish a new FTB service.[260] Under the proposed FTB service, "shippers may make at least two additional nomination cycles over the course of a gas day," which Trailblazer stated will increase "flexibility and reliability of gas transportation service."[261] While FTB shippers will pay the same rate as Trailblazer's rate schedule FTS, Trailblazer also stated that shippers under FTB service will be subject to an "Enhanced Hourly Delivery Charge for quantities in excess of the shipper's Maximum Hourly Quantities," as well as Authorized Overrun Service charges "[f]or daily volumes delivered in excess of the Maximum Daily Quantity."[262] While the FERC accepted Trailblazer's filing, it ruled that Trailblazer cannot reserve capacity equal to the sum of each FTB service shipper's Maximum Daily Quantity in order to provide FTB service.[263]

O. Open Seasons

In *ConocoPhillips v. Texas Eastern Transmission, LP*, the FERC dismissed a complaint filed during the pre-filing process by a pipeline's current shipper, alleging that the pipeline should have accepted its offer of turned-back capacity in a reverse open season.[264] The shipper alleged that the FERC should require

254. *Id.* at P 2.
255. *Id.* at P 3.
256. *Id.* at P 7.
257. *Id.* at P 28.
258. *Id.* at PP 42, 64.
259. *Id.* at P 1.
260. *Trailblazer Pipeline Co.*, 143 F.E.R.C. ¶ 61,084 at P 1 (2013).
261. *Id.* at PP 4, 8.
262. *Id*. at PP 6, 7.
263. *Id*. at PP 24-25.
264. *ConocoPhillips Co. v. Texas E. Transmission, LP*, 141 F.E.R.C. ¶ 61,071 at P 4 (2012), *reh'g denied*, 142 F.E.R.C. ¶ 61,123 (2013).

that the pipeline alter the proposed route to a different segment of its system in order to allow it to incorporate the turned-back capacity of the shipper available on that segment, but not available on the planned expansion route, thus resulting in unnecessary costs and environmental disruption.[265] The FERC dismissed the complaint, finding that because the project was only in the pre-filing stage, it was premature to consider the complaint, given that the pre-filing process sometimes resulted in route changes, and because the proceeding in which the certificate application was filed would be the best forum for assessing the claims made in the complaint.[266]

The shipper sought rehearing, and in its rehearing order, the FERC affirmed its prior decision on similar grounds.[267] Although the shipper argued that addressing the issue via complaint would result in greater administrative efficiency,[268] the FERC held first that determining how it should achieve administrative efficiency is within its discretion[269] and that in its view, the issues raised by the complaint—environmental and economic—were best examined within the context of the certificate application.[270] The FERC also noted that in the pre-filing process, its Staff had sought information relevant to the concerns expressed by the shipper[271] and further that because the pipeline could be required to accept more capacity via turn-back in its certificate proceeding, the shipper had not yet been harmed.[272]

P. Pressure Commitments

In *Gas Transmission Northwest LLC* (GTN), the FERC issued an order that granted rehearing[273] of a prior order which required GTN to modify proposed tariff language outlining its procedures for entering into mutually agreed upon pressure commitments with shippers to state that GTN would not agree to pressure commitments that would alter its available capacity, in place of proposed language that stated merely that GTN would "not be required" to do so.[274] GTN argued on rehearing that its proposed language would not permit GTN to alter its certificated capacity, which would require approval from the FERC, but instead would only permit it to decrement unsubscribed capacity that was available for sale.[275] GTN further contended that its proposed language "would prevent GTN from agreeing to a pressure commitment that would affect its existing firm service obligations" and that the FERC had recognized that "pressure commitments may affect a pipeline's . . . available capacity by an amount greater than the contract quantity."[276] Finally, GTN noted that it had a

265. 141 F.E.R.C. ¶ 61,071 at PP 1-2.
266. *Id*. at PP 4-5.
267. 142 F.E.R.C. ¶ 61,123 at P 1.
268. *Id.* at P 9.
269. *Id.* at P 10.
270. *Id.* at P 12.
271. *Id.* at P 14.
272. *Id.* at P 15.
273. *Gas Transmission Nw. LLC*, 141 F.E.R.C. ¶ 61,101 at P 2 (2012).
274. *Gas Transmission Nw. LLC*, 137 F.E.R.C. ¶ 61,115 at P 7 & n.4 (2011).
275. 141 F.E.R.C. ¶ 61,101 at P 6.
276. *Id.* at P 7.

"significant amount of unsubscribed capacity" and that the tariff language at issue would help it to utilize that unsubscribed capacity, consistent with the FERC's policy encouraging pipelines to utilize unsubscribed capacity.[277]

On rehearing, the FERC concluded that GTN should have the flexibility "to enter into a service agreement with a pressure commitment that may reduce available unsubscribed capacity on a portion of its system by more than the contract demand of the service agreement."[278] The FERC noted that this flexibility "should enhance GTN's ability to market currently unsubscribed capacity to long-term firm shippers[,]" which would benefit all of GTN's customers enabling the pipeline to spread its fixed costs over more units of service.[279] However, the FERC required GTN to "revise its proposed tariff language to include a requirement that," before entering into a "service agreement with such a pressure commitment," GTN must give notice so that other shippers will have an "opportunity to obtain the capacity without such a pressure commitment."[280]

Q. Rate Cases

1. *Portland Natural Gas Transmission System*, 142 F.E.R.C. ¶ 61,198 (2013).

On March 21, 2013, the FERC issued Opinion No. 510-A,[281] addressing requests for rehearing and clarification of its February 17, 2011, order, Opinion No. 510.[282] This docket concerns Portland Natural Gas Transmission System's (Portland) April 2008 section 4 rate filing.[283] In pertinent part, Opinion 510-A addressed five issues on rehearing of Opinion 510.[284]

First, Portland requested rehearing regarding the approved amount of Pipeline Integrity Project (PIP) costs on the grounds that the FERC improperly relied on a mix of actual and projected costs over a shortened, non-contiguous period.[285] Portland maintained that a five-year average of actual and projected costs yields a more accurate amount.[286] The FERC rejected this request and reiterated that its goal is to develop rates that are representative of costs that are incurred to provide service.[287] The FERC held that Portland's historic cost data

277. *Id.* at P 8.

278. *Id.* at P 15.

279. *Id.*

280. *Id.* at P 16. The FERC also noted GTN's commitment not to agree to any pressure commitments that would alter its certificated capacity or that would render it unable to meet its existing firm obligations. *Id.* at PP 17-18.

281. Opinion No. 510-A, *Portland Natural Gas Transmission Sys.*, 142 F.E.R.C. ¶ 61,198 (2013) [hereinafter Opinion No. 510-A].

282. Opinion No. 510, *Portland Natural Gas Transmission Sys.*, 134 F.E.R.C. ¶ 61,129 (2011) [hereinafter Opinion 510].

283. Opinion No. 510-A, *supra* note 281, at P 1.

284. As explained below, these issues involve: (1) the appropriate method for determining Pipeline Integrity Project costs, (2) at-risk conditions for underutilized capacity, (3) rate design volumes, (4) the appropriate treatment of bankruptcy proceeds, and (5) return on equity. *Id.*

285. *Id.* at PP 25, 30.

286. *Id.* at PP 25-31.

287. *Id.* at P 34.

is not reflective of anticipated expenditures in the future.[288] However, the FERC granted rehearing to permit a further refinement of an out-of-test period adjustment to account for actual cost data from the fourth quarter of 2008, which was used to calculate PIP expenses.[289]

Second, the FERC addressed three requests for rehearing concerning at-risk conditions for underutilized capacity.[290] Citing existing precedent, the FERC first explained that because pipelines are in the best position to recognize industry needs, they should bear the risks associated with unsubscribed capacity when building underutilized infrastructure.[291] Applying that precedent, the FERC granted a request for rehearing that argued the FERC understated Portland's at-risk capacity.[292] Next, the FERC addressed Portland's request for rehearing regarding whether the at-risk condition permits it to design rates based on design capacity pursuant to a 1996 order, rather than on projected billing determinants.[293] The FERC rejected Portland's request, finding that Opinion No. 510 "did not change how Portland's at-risk condition is determined and Portland's billing determinants can be greater than Portland's at-risk condition."[294] Finally, the FERC granted Portland's request for clarification that any rate issues associated with Portland's reduction of 168,000 Mcf/day in capacity would be addressed in Docket No. RP10-729.[295]

Third, the FERC denied several rehearing requests related to rate design volumes.[296] Specifically, the FERC rejected a request for rehearing that would have required Portland to both allocate costs to interruptible services and credit revenues from interruptible services to the cost of service.[297] Next, the FERC rejected Portland's contentions that the FERC erred by requiring Portland to include in its rate design volumes contract demand associated with the rejected contracts and the interruptible and short-term firm billing determinants associated with Portland's remarketing of capacity and by requiring Portland to credit bankruptcy proceeds against its rate base.[298] With regard to the rejected contracts and remarketed capacity, the FERC held that Portland failed to distinguish its circumstances from the facts presented in analogous cases.[299]

288. *Id.*

289. *Id.* at P 38.

290. *Id.* at PP 50-65.

291. *Id.* at PP 43-46 (citing *Portland Natural Gas Transmission Sys.*, 76 F.E.R.C. ¶ 61,123 (1996), *order on reh'g*, 80 F.E.R.C. ¶ 61,134 (1997), *order on reh'g*, 80 F.E.R.C. ¶ 61,345 (1997); *Koch Gateway Pipeline Co.*, 79 F.E.R.C. ¶ 61,115 (1997); *Certification of New Interstate Natural Gas Pipeline Facilities*, 88 F.E.R.C. ¶ 61,227 (1999); *Questar Pipeline Co.*, 65 F.E.R.C. ¶ 61,033 (1993)).

292. *Id.* at PP 50-54. In granting rehearing, the FERC found that the at-risk condition should be 217,405 Dth/d as opposed to 210,840 Dth/d. *Id.* at PP 55-59.

293. *Id.* at P 60.

294. *Id.* at P 61; *see also id.* at PP 62-65.

295. *Id.* at PP 66-67.

296. *Id.* at PP 68-116.

297. *Id.* at PP 81-87.

298. *Id.* at PP 97-116.

299. *Id.* at PP 102-13 (citing *Trailblazer Pipeline Co.*, 80 F.E.R.C. ¶ 61,141 (1997), *order on reh'g*, 81 F.E.R.C. ¶ 61,032 (1997); *Wyoming Interstate Co.*, 87 F.E.R.C. ¶ 61,339 (1999)).

Concerning the argument regarding bankruptcy proceeds, the FERC held that Portland's reliance on a prior decision was misplaced.[300]

Fourth, the FERC addressed additional requests for rehearing by Portland regarding the use of bankruptcy proceeds to offset rate base.[301] Portland's arguments challenged findings regarding burden of proof, the rationale for reducing rate base, treatment of rate base reduction in levelized rates, whether the FERC engaged in retroactive rulemaking, risks and benefits of bankruptcy outcomes, capital structure impact on revenues, due process, and applicable precedent for determining reasonable returns.[302] The FERC rejected Portland's burden of proof arguments, finding that section 4 applicants bear the burden of proof of supporting proposed rate increases.[303] In any event, the FERC found that its decision would satisfy the requirements of section 5.[304] In rejecting Portland's arguments concerning the rationale for the reduced rate base, the FERC dismissed the argument that it is treating the bankruptcy proceeds as a return of Portland's investment.[305] Rather, the FERC found that its decision is analogous to its traditional treatment of accumulated deferred income taxes.[306] Concerning Portland's request for rehearing regarding the treatment of the rate base reduction in levelized rates, the FERC clarified that the rate base adjustment for bankruptcy proceeds is a component of the levelized cost of service model.[307] Accordingly, the FERC found that use of its model is "consistent with the purpose of rate base reduction"—to reduce rate base by prepaid amounts—and also recognized that bankruptcy proceeds were intended as partial compensation for payments that would have otherwise been made.[308] Next, the FERC granted in part and denied in part Portland's request for rehearing regarding claims of impermissible retroactive rulemaking, agreeing that any payments that would have been made prior to the effective date of the rates were improperly considered in designing rates.[309] The FERC rejected Portland's contention that it departed from precedent and required "investors to bear the risk of unfavorable outcomes in bankruptcy . . . while denying them the benefits of successful outcomes."[310] With regard to capital structure, the FERC denied Portland's argument that the FERC erred by failing to consider the revenue impact that the bankruptcy proceeds treatment would have on Portland.[311] Concerning Portland's due process arguments, the FERC rejected the contention that it erred

300. *Id.* at PP 114-15 (citing Opinion No. 486, *Kern River Gas Transmission Co.*, 117 F.E.R.C. ¶ 61,077 (2006), *order on reh'g*, Opinion No. 486-A, 123 F.E.R.C. ¶ 61,056 (2008), *order on reh'g*, Opinion No. 486-B, 126 F.E.R.C. ¶ 61,034 (2009), *order on reh'g and compliance*, Opinion No. 486-C, 129 F.E.R.C. ¶ 61,240 (2009), *order on reh'g*, Opinion No. 486-D, 133 F.E.R.C. ¶ 61,162 (2010), *order on initial decision*, Order No. 486-E, 136 F.E.R.C. ¶ 61,045 (2011), *order on reh'g*, Opinion No. 486-F, 142 F.E.R.C. ¶ 61,132 (2012)).

301. *Id.* at PP 117-76.

302. *Id*. at PP 120-21, 127-28, 137-38, 143-46, 151-53, 159-60, 163, 167, 169-71.

303. *Id.* at PP 123-25.

304. *Id.* at P 126.

305. *Id.* at PP 129-31.

306. *Id*. at P 132.

307. *Id.* at PP 137-40.

308. *Id.* at P 140.

309. *Id.* at PP 147-48.

310. *Id.* at PP 152, 154.

311. *Id.* at P 162.

by failing to give notice of the methodology to be used in treatment of the bankruptcy proceeds.[312] Finally, the FERC rejected Portland's argument that the reduction of cost of service based on the bankruptcy award would violate the applicable standards for determining reasonable returns for pipelines on the grounds that Portland agreed to the at-risk condition in its certificate proceeding.[313]

Fifth, the FERC addressed several participants' requests for rehearing regarding the derivation of Portland's 12.99% return on equity.[314] In denying the rehearing requests, the FERC stated that it followed its long-standing policy of using current available data but excluding post-hearing data.[315] In addition, the FERC upheld its decision to place Portland at the median of the proxy group range.[316]

2. *Portland Natural Gas Transmission System*, 142 F.E.R.C. ¶ 61,197 (2013).

On March 21, 2013, the FERC issued Opinion No. 524, affirming in part and reversing in part the determinations contained in an administrative law judge's (ALJ) initial decision[317] regarding the section 4 rate case filed by Portland on May 12, 2010.[318] Opinion No. 524 affirmed the initial decision in ten key respects.[319] One, the FERC agreed with the ALJ that PIP expenses should be $532,556, a figure that was based on the last twelve months of the test period, rather than the $790,806 figure proposed by Portland or the annualized amount of $289,654 proposed by Trial Staff.[320] The FERC determined that the ALJ's finding was supported by a preponderance of the evidence and was consistent with the FERC's findings in Opinion No. 510.[321] Two, the FERC agreed with the ALJ that "[i]t is unjust and unreasonable" for Portland's rates to include "outside service costs billed to [Portland] by . . . affiliated service companies in excess of those companies' costs."[322] Three, the FERC agreed with the ALJ "that Portland is required to maintain sufficiently detailed records"—even though such record keeping duplicates records maintained by Portland's majority owner, TransCanada Corporation (TransCanada)—in order to permit the appropriate review required by the Natural Gas Act.[323] Four, the FERC addressed the issue of revised ad valorem tax payment amounts that were

312. *Id.* at PP 163-65.

313. *Id.* at PP 172-76 (discussing Federal Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1944); Bluefield Water Works & Improvement Co. v. Public Serv. Comm'n of W. Va., 262 U.S. 679 (1923)).

314. *Id.* at PP 182-203.

315. *Id.* at PP 204-33.

316. *Id.* at P 241.

317. *Portland Natural Gas Transmission Sys.*, 137 F.E.R.C. ¶ 63,018 (2011).

318. Opinion No. 524, *Portland Natural Gas Transmission Sys.*, 142 F.E.R.C. ¶ 61,197 at P 2 (2013).

319. *Id.* at P 10.

320. *Id.* at PP 66-74.

321. *Id.* at P 71 (citing Opinion No. 510, *supra* note 282, at P 85; 18 C.F.R. § 154.303(a)(1)-(4) (2013)).

322. *Id.* at P 54. The FERC also upheld the ALJ's finding that Portland failed to meet its burden of showing that outside service costs were based on the costs assessed by affiliated companies were negotiated at arm's length. *Id.* at PP 54-59.

323. *Id.* at PP 60, 65.

contained in Portland's forty-five-day update filing.[324] Although Portland's revised ad valorem tax payments were not made in the test year, the FERC affirmed the initial decision's acceptance of the revised amounts as the most current projection of future costs.[325] The fifth issue pertained to the prepaid tax allowance in working capital.[326] Affirming the ALJ, and relying on its prior finding in Opinion No. 510, the FERC found that Portland established, by a preponderance of the evidence, that the prepaid tax should not be removed from rate base.[327] Six, the FERC upheld the ALJ's calculation of the levelized cost of service, which used average rate base instead of end of test period rate base balances; the FERC agreed that Portland obligated itself in a prior settlement to use average rate base figures.[328] Seven, the FERC agreed with the ALJ that Portland's depreciation rate should be 2%.[329] In support of its decision, the FERC cited the ALJ's findings regarding the deficiencies in Portland's gas supply study.[330] Eight, the FERC affirmed the ALJ's findings regarding negative salvage, including the ALJ's acceptance of a blended and weighted mix of union and non-union labor from across Portland's plant locations for purposes of projecting the labor costs Portland will incur when it retires a plant, the appropriate sales price for line pack at decommissioning (i.e., an estimate that was close to the average price of gas at Dracut during the test period), and the appropriate recovery period for negative salvage costs (i.e., the period should be the same as the depreciable life period).[331] Nine, the FERC addressed Portland's proposal to establish the debt component of its capital structure "using the net proceeds, rather than the gross proceeds, of debt."[332] The FERC agreed with the ALJ, found Portland's proposal to be unjust and unreasonable, and required Portland to use the gross proceeds method pursuant to precedent.[333] Thus, the FERC established Portland's capital structure as 52.84% equity and 47.16% debt.[334] Finally, the FERC upheld the ALJ's finding that it is appropriate to include the costs attributable to debt swaps in calculating debt costs.[335]

In Opinion No. 524, the FERC also reversed the ALJ's Initial Decision on five issues.[336] One, the FERC reversed the ALJ's finding that Portland's cost of debt is 7.09%.[337] Instead, the FERC approved a 6.825% cost of debt, which

324. *Id.* at PP 75-81.

325. *Id.* at PP 80-81.

326. *Id.* at PP 82-93.

327. *Id.* at PP 92-93 (citing Opinion No. 510, *supra* note, 282 at P 155).

328. *Id.* at PP 113-19.

329. *Id.* at P 142.

330. *Id.* at PP 142-47, 149. The FERC also rejected Trial Staff's proposed depreciation rate on the grounds that Trial Staff's "production model is based on an arbitrarily selected economic end life and [Trial] Staff's witness does not explain how he arrived at the numbers that made up his end life recommendations." *Id.* at P 148.

331. *Id.* at PP 162-64, 170-73.

332. *Id.* at PP 248-62.

333. *Id.* at PP 263-65 (discussing Opinion No. 446, *System Energy Res., Inc.*, 92 F.E.R.C. ¶ 61,119 (2000), *reh'g denied*, Opinion No. 446-A, 96 F.E.R.C. ¶ 61,165 (2001)).

334. *Id.* at PP 266-67.

335. *Id.* at P 283.

336. *Id.* at P 10.

337. *Id.* at P 283.

Portland introduced in its initial brief.[338] Two, the FERC "reverse[d] the ALJ's decision . . . to allow Portland to include regulatory expenses that were not effective in the test period and . . . exclude [certain] expenses" that were supported by invoices from TransCanada.[339] Three, the FERC reversed the ALJ on several findings relating to Portland's at-risk condition.[340] The FERC held that the ALJ erred in finding that "Portland's capacity entitlements on joint facilities were irrelevant to the at-risk condition" and, therefore, erred in establishing the at-risk condition at 168,672 decatherms per day (Dth/d).[341] Rather, the FERC held that Portland's at-risk condition, as well as its billing determinants, should be 210,840 Mcf/day.[342] The FERC also found that the ALJ erred in requiring Portland to credit interruptible and park and loan revenues to its cost of service.[343] Four, the FERC reversed the ALJ's decision to use a new, "cost of credit" approach formula for calculating an annual credit against its cost of service to account for bankruptcy proceeds.[344] Instead, the FERC directed Portland to use a rate base reduction method to account for bankruptcy proceeds.[345] Five, the FERC overturned the ALJ's finding that Portland's return on equity should be at the median of the proxy group's zone of reasonableness, or 10.28%.[346] Rather, the FERC held that Portland should be at the top of the zone, and that the zone should include Trial Staff's discounted cash flow analysis for El Paso Partners and that Portland's return on equity should be 11.59%.[347]

3. *Kern River Transmission Co.*, 142 F.E.R.C. ¶ 61,132 (2013).

On February 22, 2013, the FERC issued Opinion No. 486-F, which, with one exception, denied rehearing requests relating to Opinion No. 486-E[348] in Kern River Gas Transmission Company's (Kern River) Period Two step-down rate proceeding.[349] In Opinion No. 486-F, the FERC also accepted Kern River's compliance filing in response to an August 29, 2011, order.[350]

First, the FERC denied requests for rehearing that alleged the FERC "erred by establishing a preference" for Kern River's proposed remedy in contravention of section 5 of the NGA.[351] The FERC found that a "limited preference for the pipeline's proposed remedy is consistent with the structure of the NGA" only where, as here, the pipeline satisfies the FERC that "its proposed remedy is just

338. *Id.*
339. *Id.* at PP 27-34.
340. *Id.* at P 207.
341. *Id.*
342. *Id.* at PP 207-26.
343. *Id.* at PP 232-34.
344. *Id.* at PP 235-47.
345. *Id.* at PP 245-47.
346. *Id.* at P 290.
347. *Id.* at PP 317-22, 395.
348. Opinion No. 486-E, *Kern River Transmission Co.*, 136 F.E.R.C. ¶ 61,045 (2011).
349. Opinion No.486-F, *Kern River Transmission Co.*, 142 F.E.R.C. ¶ 61,132 (2013).
350. *Id.* at P 361 (discussing *Kern River Gas Transmission Co.*, 136 F.E.R.C. ¶ 61,141 (2011)).
351. *Id.* at PP 28-45.

and reasonable."[352] Second, the FERC rejected rehearing requests relating to Kern River's proposal to levelize the recovery of the 30% of its invested capital that remained at the end of the terms of ten or fifteen-year contracts for Period Two service.[353] Certain shippers had argued that the capital should be recovered over the depreciable life of the assets, which lasted longer than Period Two.[354] The FERC disagreed, finding that, under such a proposal, shippers could take advantage of lower rates during the first half of the levelization period and free themselves of any commitment to pay higher rates during the second half, thereby preventing Kern River from earning a reasonable return.[355] Third, the FERC denied, with one exception, Kern River's rehearing request regarding its obligation to offer service to its levelized rate shippers at stepped-down Period Three rates that reflect removal of all Kern River's original invested capital from rate base.[356] The exception permitted Kern River to submit the rates only for shippers whose Period Two contracts would expire in two years.[357] Fourth, the FERC denied Kern River's request for rehearing, which argued that compressor replacement costs incurred after the test period should be incorporated into the Period Two rate base.[358] In denying rehearing, the FERC found that Kern River failed to make a persuasive showing that would justify a test period adjustment for the compressor costs.[359] Fifth, Kern River sought rehearing of the FERC's determination of the appropriate billing determinants for Period Two.[360] In support of its decision, the FERC found that its "requirement that Kern River design its Period Two rates based upon . . . actual 2004 test period billing determinants is consistent with test period regulations and policies," and Kern River "provided no basis to depart from those policies."[361] Finally, the FERC denied all challenges to its rate of return determinations.[362] In particular, the FERC reaffirmed that "standard capital structure polices do not apply" when using a levelized rate design.[363] Thus, the FERC upheld Kern River's 100% equity capital structure used in calculating Period Two rates.[364] The FERC also rejected arguments that Kern River's return on equity should be decreased because Kern River faced no financial risk.[365] "On balance, the [FERC] concluded that there was no compelling evidence that a 2004 investor would

352. *Id.* at P 36.

353. *Id.* at PP 46-61.

354. *Id.* at P 47.

355. *Id.* at PP 71-72. In support of its decision, the FERC found that its decision was consistent with prior orders regarding Kern River. *Id.* at PP 85-107.

356. *Id.* at PP 109-29.

357. *Id.* at P 118.

358. *Id.* at PP 131-54.

359. *Id.* at PP 155-69.

360. *Id.* at PP 180-84.

361. *Id.* at PP 185-203.

362. *Id.* at PP 204-63.

363. *Id.* at P 213.

364. *Id.* at PP 213-19.

365. *Id.* at PP 228-41.

have perceived that Kern River would be a pipeline of greater or lower than average risk."[366]

In conjunction with its findings in rehearing, Opinion No. 486-F also resolved discrete issues related to Kern River's Opinion No. 486-E compliance filing, as well as a settlement relating to self-contained contracts.[367]

4. *National Fuel Gas Supply Corp.*, 140 F.E.R.C. ¶ 61,114 (2012).

On August 6, 2012, the FERC issued an order approving "as fair and reasonable and in the public interest" an unopposed stipulation and partial agreement regarding National Fuel Gas Supply Corporation's (National Fuel) October 31, 2011, section 4 rate filing.[368] The partial agreement established National Fuel's cost of service at $166,500,000.[369] In pertinent part, the partial agreement also resolved issues pertaining to gathering rates, retainage factors, electric power costs, depreciation rates, the effect of the roll-in National Fuel's Niagara facilities, the requirement for National Fuel to file its next general rate case by January 1, 2016, post-retirement benefits other than pensions, deferred income taxes, and the return on equity to be used in certificate proceedings and for allowance for funds used during construction.[370]

5. *Southern Natural Gas Co.*, 142 F.E.R.C. ¶ 61,078 (2013).

On January 31, 2013, the FERC issued an order addressing Southern Natural Gas Company, L.L.C.'s (Southern) December 21, 2012, petition to amend an existing stipulation and agreement by postponing the date on which Southern's section 4 rate case filing was due.[371] Southern argued that the delay would help facilitate a pre-filing settlement.[372] One participant opposed Southern's request,[373] arguing, inter alia, that amendments to the agreement must satisfy the public interest standard.[374] Based on its finding that a three-month deferral will substantially preserve the agreement and provide the added benefit of potentially obviating the need for the rate filing, the FERC granted Southern's petition, subject to conditions.[375] Specifically, the FERC accepted Southern's commitment to waive the refund floor in the event rates must be reduced below current levels.[376] Second, the FERC required that Southern: (1) must use a test period as if it filed its section 4 rate application on February 28, 2013; (2) must

366. *Id.* at P 263.

367. *Id.* at PP 264-337 (discussing the February 1, 2012 order approving the settlement, *Kern River Gas Transmission Co.*, 138 F.E.R.C. ¶ 61,078 (2012)).

368. *National Fuel Gas Supply Corp.*, 140 F.E.R.C. ¶ 61,114 at PP 1, 4 (2012).

369. *Id.* at P 11.

370. *Id.* at PP 12, 14-21. The partial settlement also specified additional procedures for resolving questions regarding reservation charge credits, pooling, and the implementation of storage service enhancements. *Id.* at PP 1 & n.2, 22-24.

371. *Southern Natural Gas Co.*, 142 F.E.R.C. ¶ 61,078 at P 1 (2013).

372. *Id.* at PP 5-8.

373. *Id.* at PP 10-18.

374. *Id.* at P 16 (citing *In re* Permian Basin Area Rate Cases, 380 U.S. 747, 822 (1968); Arkansas La. Gas Co. v. Hall, 453 U.S. 571, 582 (1981)).

375. *Id.* at PP 25-28.

376. *Id.* at PP 29-30.

use a base period that does not end more than four months before February 28, 2013; and (3) may not use an adjustment period that extends more than nine months beyond February 28, 2012.[377]

6. *CenterPoint Energy—Miss. River Transmission, LLC*, 140 F.E.R.C. ¶61,253 (2012).

On September 28, 2012, the FERC issued an order accepting CenterPoint Energy—Mississippi River Transmission, LLC's (MRT) August, 22, 2012, section 4 rate filing.[378] In general, the FERC established hearing procedures to explore issues pertaining to "cost of service, cost allocation, and rate design for the existing and new services" that were raised by MRT's filing.[379] However, while the FERC set MRT's proposed reliability compliance cost surcharge for hearing, it rejected outright MRT's proposal to include in that such surcharge any costs related to environmental regulations or pipeline safety.[380] The FERC found that inclusion of costs associated with environmental regulations or pipeline safety in a surcharge mechanism conflicts with existing precedent.[381]

7. *Transcontinental Gas Pipe Line Co.*, 140 F.E.R.C. ¶ 61,251 (2012).

On September 28, 2012, the FERC issued an order accepting, suspending, and establishing a hearing regarding Transcontinental Gas Pipe Line Company, LLC's (Transco) August 31, 2012, section 4 rate filing.[382] With respect to those services where Transco proposed an overall rate increase, the FERC accepted and suspended the proposed tariff records, subject to refund.[383] However, it accepted, without suspension, the proposed tariff records for incremental services where there was an overall rate decrease.[384] The FERC also addressed protests regarding Transco's pending application in Docket No. CP11-551-000 to abandon its Eminence storage field.[385] The FERC made clear that its suspension order in the rate proceeding did not prejudge any issues in the abandonment proceeding.[386] "To the extent the [FERC] act[ed] in Docket No. CP11-551-000 prior to the conclusion of the test period in this proceeding, then the parties may discuss the effect of abandonment on the rates at issue in

377. *Id.* at PP 32-35.

378. *CenterPoint Energy—Miss. River Transmission, LLC*, 140 F.E.R.C. ¶ 61,253 at PP 1-2 (2012).

379. *Id.* at PP 62, 68-69, 72-73, 77-79.

380. *Id.* at PP 2, 63.

381. *Id.* at PP 64-65 (citing *Granite State Gas Transmission Inc.*, 132 F.E.R.C. ¶ 61,089 (2010); *Florida Gas Transmission Co.*, 105 F.E.R.C. ¶ 61,171 (2003), *reh'g granted in part*, 107 F.E.R.C. ¶ 61,074 (2004), *reh'g dismissed*, 109 F.E.R.C. ¶ 61,320 (2004); *Extraordinary Expenditures Necessary to Safeguard National Energy Supplies*, 96 F.E.R.C. ¶ 61,299 (2001)).

382. *Transcontinental Gas Pipe Line Co*., 140 F.E.R.C. ¶ 61,251 (2012). In generally setting the proceeding for hearing, the FERC rejected a request for summary disposition regarding Transco's return on equity and explicitly set that issue for hearing. *Id.* at P 37.

383. *Id.* at PP 1, 28.

384. *Id.* at PP 1, 29 (explaining that, because Transco did not include in its filing a motion to move its rates into effect, the FERC accepted certain tariff records without suspension in order to require Transco to implement the overall rate decreases for the relevant incrementally priced expansion services and liquefied natural gas services) (citing Northeast Energy Ass'n. v. FERC, 158 F.3d 150 (D.C. Cir. 1998)).

385. *Id.* at PP 3, 18, 21.

386. *Id.* at P 32.

this proceeding."[387] The FERC explained, however, that if it did not take action "in Docket No. CP11-551-000 prior to the end of the test period, then the expected accounting changes" resulting from the proposed abandonment cannot be considered as a part of the rate proceeding because they would not be known and measurable.[388]

8. *El Paso Natural Gas Co.*, 140 F.E.R.C. ¶ 61,148 (2012).

On August 27, 2012, the FERC issued an order on clarification and compliance with respect to its May 4, 2012 order[389] on rehearing of an earlier technical conference order,[390] stemming from El Paso Natural Gas Company's (EPNG) 2008 section 4 rate filing.[391] The FERC addressed requests for clarification or rehearing of two issues: (1) "the appropriate rate for the scheduling and overrun component" of EPNG's hourly scheduling penalty; and (2) the effect, if any, of the FERC's statements regarding "existing sculpted contract rights."[392] On the first issue, the FERC characterized EPNG's request as seeking "clarification, or in the alternative rehearing, that the [FERC] intended to exercise its authority under section 5 of the NGA to change the rate that applies only to the hourly scheduling component of [EPNG's] Hourly Scheduling Penalty Quantity"—i.e., that the FERC did not intend to change the non-critical unauthorized hourly overrun quantities component—"from two times the 100[%] load factor equivalent [interruptible rate] to one times that rate."[393] Although the FERC "look[ed] with disfavor on [EPNG's] introduction of this issue at this late stage of the proceeding" and denied rehearing, it nonetheless granted clarification.[394] In particular, "[t]o remove any uncertainty," the FERC clarified that its requirement was for EPNG to revise its rate for the hourly scheduling penalty, "comprised of both the hourly scheduling quantities and the unauthorized hourly overrun quantities, to 100[%]t load factor [interruptible] rate."[395] However, the FERC clarified that EPNG "may maintain an unauthorized daily overrun rate at two times the 100 percent load factor [interruptible] rate."[396] With respect to the second issue, the FERC granted clarification, explained that its comments regarding sculpted contracts were "general observations," and concluded that its statements "should not be taken as findings of fact applicable to the circumstances that may arise in future proceedings."[397]

387. *Id.* at P 33.
388. *Id.* at P 34.
389. *El Paso Natural Gas Co.*, 139 F.E.R.C. ¶ 61,096 (2012).
390. *El Paso Natural Gas Co.*, 125 F.E.R.C. ¶ 61,309 (2008).
391. *El Paso Natural Gas Co.*, 140 F.E.R.C. ¶ 61,148 at PP 1-2 (2012).
392. *Id.* at P 5.
393. *Id.* at P 21.
394. *Id.* at PP 22-23.
395. *Id.* at P 23.
396. *Id.*
397. *Id.* at P 27.

R. Rate Investigations

1. *Bear Creek Storage Co.*, 140 F.E.R.C. ¶ 61,129 (2012).

The FERC continued to pursue investigations sua sponte, under NGA section 5, into the justness and reasonableness of the rates charged by specific interstate natural gas pipelines.[398]

On August 15, 2012, the FERC approved an uncontested settlement filed by Bear Creek Storage Company L.L.C. (Bear Creek) thereby resolving the Commission-initiated investigation into Bear Creek's rates.[399]

2. *Wyoming Interstate Co.*, 141 F.E.R.C. ¶ 61,117 (2012).

In *Wyoming Interstate Co.*, the FERC determined that Wyoming Interstate appeared to be "substantially over-recovering its cost of service" based on the cost and revenue information provided by Wyoming Interstate in its 2010 and 2011 FERC Form No. 2 submissions.[400] The FERC initiated an investigation into the justness and reasonableness of Wyoming Interstate's rates.[401]

3. *Viking Gas Transmission Co.*, 141 F.E.R.C. ¶ 61,118 (2102).

In *Viking Gas Transmission Co.*, the FERC determined that Viking appeared to be "substantially over-recovering its cost of service" based on the cost and revenue information provided by Viking in its 2010 and 2011 FERC Form No. 2 submissions.[402] The FERC initiated an investigation into the justness and reasonableness of Viking's rates.[403]

S. Reservation Charge Credits for Curtailment

1. *Gulf Crossing Pipeline Co.*, 141 F.E.R.C. ¶ 61,222 (2012).

In *Gulf Crossing Pipeline Co.*,[404] the FERC found that revising the "definition of force majeure to include all testing, repair, replacement, refurbishment, or maintenance activity required to comply with the [Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011 (2011 Act)] and ongoing [Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA)] rulemaking proceedings is overbroad."[405] However, it is reasonable to "allow partial reservation charge crediting for a transitional two-year period for outages due to orders PHMSA may issue pursuant to section 60139(c) of chapter 601 of title 49, as added by section 23 of the 2011 Act."[406] Because they relate to "one-time non-recurring events[,] . . . the pipeline could have less discretion concerning the timing of

398. *Bear Creek Storage Co.*, 140 F.E.R.C. ¶ 61,129 at P 1 (2012).
399. *Id.* at PP 18-19.
400. *Wyoming Interstate Co.*, 141 F.E.R.C. ¶ 61,117 at PP 1, 6-7 (2012).
401. *Id*. at P 8.
402. *Viking Gas Transmission Co.*, 141 F.E.R.C. ¶ 61,118 at PP 1, 6-7 (2012).
403. *Id.* at P 8.
404. *Gulf Crossing Pipeline Co.*, 141 F.E.R.C. ¶ 61,222 (2012).
405. *Id.* at P 28.
406. *Id.*

testing . . . than it has concerning the timing and location of routine scheduled maintenance,"[407] and the related costs "would generally not be recurring costs eligible for inclusion in a pipeline's rates in a general section 4 rate case."[408] Also, "when there is no advance notice of an outage, . . . credits [must be provided] based on the amount of primary firm service[,] which the shipper nominated for scheduling, but the pipeline was unable to schedule or deliver because of a non-force majeure event,"[409] and "the seven days average [can] only be used when [the pipeline] has posted notice before the Timely Cycle Nomination deadline that the capacity will be unavailable."[410] Credits can be reduced "only [in] those circumstances where [the pipeline's] failure to provide service is due to events or conduct of others outside of its control which result in an outage of reserved firm service."[411] Further, "in a force majeure event when both the pipeline's and the facilities of others are affected, then the traditional force majeure rule applies[,] and the pipeline is required to provide partial credits."[412] Furthermore, "pipeline service may be 'curtailed' in an emergency situation or when an unexpected capacity loss occurs after the pipeline has scheduled service" but not for "routine repair or maintenance."[413] Finally, a definition of force majeure that includes "the necessity for testing (as required by governmental authority or as deemed necessary for safe operation by the testing party)" is overbroad, and this language must be removed from the definition.[414]

2. *Northern Natural Gas Co.*, 141 F.E.R.C. ¶ 61,221 (2012).

Northern Natural Gas Co. is "an order denying rehearing and on compliance filing following an order requiring Northern Natural Gas Company [(Northern)] to revise its reservation charge crediting tariff provisions to be consistent with Commission policy."[415] The FERC affirmed that "a non-[Straight Fixed Variable (SFV)] rate design [must] achieve an equitable sharing of the costs of a force majeure outage in the same ballpark as the [n]o [p]rofit and [s]afe [h]arbor methods."[416] The FERC further affirmed that "the [n]o [p]rofit method requires the pipeline to grant partial credits equal to the pipeline's [return on equity] and associated income taxes portion of the reservation charge, thereby requiring the pipeline to forego its profit during the force majeure outage."[417] The FERC reaffirmed that "Northern's inclusion of only about 3[%] of its fixed costs in its usage charge is too small an amount to accomplish an equitable sharing of the risks of force majeure outages, without any provision for reservation charge credits" because "inclusion of 3[%] of its fixed costs in its usage charge does not result in risk sharing in the 'same

407. *Id.* at P 42.
408. *Id.* at P 43.
409. *Id.* at P 53.
410. *Id.* at P 54.
411. *Id.* at P 68.
412. *Id.* at P 69.
413. *Id.* at P 75.
414. *Id.* at PP 76, 79.
415. *Northern Natural Gas Co.*, 141 F.E.R.C. ¶ 61,221 at P 1 (2012).
416. *Id.* at P 17.
417. *Id.* at P 21.

ballpark' as under the [s]afe [h]arbor method."[418] The FERC further decided that a pipeline may not rely on a prior settlement in refusing to amend a tariff provision that is inconsistent with the reservation charge credits policy.[419] The FERC further affirmed that "a limited section 4 proceeding is appropriate to address the reservation charge crediting issue."[420] The FERC also rejected Northern's hybrid proposal that extracted the most pipeline-favorable aspects of the no profit and safe harbor methods.[421] The FERC rejected Northern's proposal to limit credits to "the minimum quantities actually required by the shipper to serve or otherwise meet the firm market"[422] because "the shipper's contractual arrangements with its downstream customers are not relevant to determining the reservation charge credits."[423] The FERC also rejected Northern's proposal "to require a shipper to file a claim for a reservation charge credit within [ten] days of the end of the service outage, and support the claim, by submission of a detailed affidavit" because a pipeline may not "require shippers to provide evidence of their market deliveries" and because "the information the pipeline was seeking in the claim procedure was already in the pipeline's possession."[424] In the case of capacity release, it is reasonable "that the reservation charge credit applicable to the replacement shipper will be the lower of the reservation rate of the releasing or the replacement shippers" as long as "the credits it provides to releasing shippers would be unaffected by any reservation charge credits it provides to the replacement shipper in either of the two above-described situations," and it is also reasonable "that if there is a volumetric rate, there will be no reservation charge credits."[425]

3. *Kern River Gas Transmission Co.*, 140 F.E.R.C. ¶ 61,146 (2012).

Kern River Gas Transmission Co. is an order on compliance filing following a prior order where the FERC rejected Kern River Gas Transmission Company's (Kern River) proposal regarding force majeure-related outages to mix elements of the safe harbor Method (full credits given to shippers after a short grace period) and the no profit method (partial credits given starting on the first day of an outage).[426] In this order, the FERC accepted Kern River's election of the safe harbor Method.[427] The FERC also accepted Kern River's proposal to base credits on the lesser of the shipper's (1) delivery maximum daily quantity (MDQ), (2) average quantities during the seven days immediately prior to an outage, and (3) the quantities nominated for the day of the event (if the shipper does not submit a nomination after notice of the outage is posted, credits are based on the lesser of (1) and (2) and no credit is given if the delivery reduction

418. *Id.* at PP 8, 23.

419. *Id.* at P 34.

420. *Id.* at P 45.

421. *Id.* at PP 71-72.

422. *Id.* at P 75.

423. *Id.* at P 78 (quoting *Kern River Gas Transmission Co*., 139 F.E.R.C. ¶ 61,044 at P 46 (2012)).

424. *Id.* at PP 81-83.

425. *Id*. at PP 84, 87.

426. *Kern River Gas Transmission Co.*, 140 F.E.R.C. ¶ 61,146 at PP 1, 3 (2012); *Kern River Gas Transmission Co.*, 139 F.E.R.C ¶ 61,044 at P 5 (2012).

427. 140 F.ER.C. ¶ 61,146 at PP 4, 7.

is due to a third party confirmation process or other actions beyond Kern River's direct control, other than force majeure outages on its facilities).[428] The FERC also accepted Kern River's proposal that if a quantity is cut during the timely nomination cycle, and the shipper nominates and Kern River schedules in a subsequent nomination cycle any previously cut quantities, the credit would be reduced accordingly.[429] However, the FERC rejected Kern River's proposal to base credits on the difference between nominated quantities and scheduled amounts and directed that credits be based on the difference between nominated quantities and delivered amounts.[430]

4. *National Fuel Gas Supply Corp.*, 143 F.E.R.C. ¶ 61,103 (2013).

National Fuel Gas Supply Corp. includes similar rulings to the above regarding the 2011 Act; outages due to operating conditions on upstream or downstream pipeline (i.e. third parties); and basing the credit on the lesser of nominated quantities, the average of the previous seven days usage (if advance notice is given), and MDQ.[431] The FERC also clarified that "if a firm shipper refuses to accept deliveries at its primary point because National Fuel has failed to make deliveries consistent with its obligations under its tariff, the shipper should be entitled to reservation charge credits."[432] The FERC found that a pipeline may "limit its obligation to provide" credits if it "works with a shipper to time an outage on its facilities to coincide with an outage on upstream or downstream facilities."[433] The FERC further clarified that a pipeline may "reflect reservation charge credits on a shipper's monthly billing invoice, with the credits reducing any amounts owed by that shipper."[434] The FERC further clarified that a pipeline may not delay credits until the "implementation of the necessary changes to [its] business system"[435] because it is not "burdensome or otherwise onerous" to make "manual billing adjustments to its customer's invoices."[436]

5. *Algonquin Gas Transmission, LLC*, 143 F.E.R.C. ¶ 61,082 (2013).

Algonquin Gas Transmission, LLC includes similar rulings to the above regarding FERC's authority to order pipelines to comply with its reservation charge credits policy, the inclusion of judicial orders in the definition of force majeure, compliance with government orders, and authorization to interrupt or curtail.[437]

428. *Id.* at PP 8, 13.
429. *Id.* at PP 15-16.
430. *Id.* at P 24.
431. *National Fuel Gas Supply Corp.*, 143 F.E.R.C. ¶ 61,103 at PP 22, 28-34 (2013).
432. *Id.* at P 38.
433. *Id.* at PP 39-45.
434. *Id.* at PP 46-49.
435. *Id.* at P 50.
436. *Id.* at P 52.
437. *Algonquin Gas Transmission, LLC*, 143 F.E.R.C. ¶ 61,082 at PP 20-31 (2013).

6. *Panhandle Eastern Pipeline LLC*, 143 F.E.R.C. ¶ 61,041 (2013).

In *Panhandle Eastern Pipeline LLC*, the FERC reaffirmed its authority to order pipelines to comply with its reservation charge credits policy and that failure to provide any credits during force majeure outages is not reasonable.[438] The FERC clarified that the definition of "force majeure [may not] include 'the necessity for making repairs or alterations to wells, machinery, or lines of pipe.'"[439] The FERC further found that existing rate case settlements, service agreements, and ongoing audits do not bar the FERC from requiring compliance with its reservation charge credits policy.[440]

7. *Rockies Express Pipeline LLC*, 142 F.E.R.C. ¶ 61,075 (2013).

Rockies Express Pipeline LLC includes similar rulings to the above regarding conditions on upstream and downstream pipelines (i.e. acts of third parties); the 2011 Act; the use of the lesser of MDQ, nominated quantity or seven-day average; when the seven-day average is used; and secondary points.[441] The FERC found that "credits [must be] provided to shippers that provide evidence to Rockies Express of having submitted nominations to another pipeline for volumes Rockies Express is unable to schedule."[442] The FERC clarified that shippers may not be required to submit nominations where the pipeline has given advance notice of an outage.[443] The FERC accepted that credits for "[c]urtailments from [activities posted on a Monthly Maintenance Schedule (MMS) would be] based on the customer's average usage over a seven-day period immediately preceding the posting" of the MMS.[444]

8. *Viking Gas Transmission Co.*, 142 F.E.R.C. ¶ 61,054 (2013).

In *Viking Gas Transmission Co.*,[445] the FERC found that "in situations where [the pipeline] has given notice of an outage before the first opportunity to schedule service for a Gas Day, the credits for that day [must] be based solely on each shipper's usage during the preceding seven days up to their contract demand, and not on shippers' nominations."[446] The FERC further clarified that using "the seven-day average in situations where there was no advance notice that the outage would continue on the day in question" is inappropriate.[447] The order included a similar ruling to the above requiring credits based on nominated quantities and not on scheduled quantities.[448]

438. *Panhandle E. Pipe Line Co.*, 143 F.E.R.C. ¶ 61,041 at PP 1, 9, 14 (2013).
439. *Id.* at PP 70-73.
440. *Id.* at PP 74-95.
441. *Rockies Express Pipeline, LLC*, 142 F.E.R.C. ¶ 61,075 (2013).
442. *Id.* at P 10.
443. *Id.* at P 32.
444. *Id.* at P 35.
445. *Viking Gas Transmission Co.*, 142 F.E.R.C. ¶ 61,054 (2013).
446. *Id.* at P 25.
447. *Id.* at P 26.
448. *Id.* at P 23.

9. *Gulf South Pipeline Co.*, 141 F.E.R.C. ¶ 61,224 (2012).

Gulf South Pipeline Co. includes similar rulings to the above regarding the 2011 Act, no notice service, absence of advance notice of an outage, use of the seven-day average, secondary points, outages due to acts of shippers or third parties, and the definition of force majeure.[449]

10. *Texas Gas Transmission, LLC*, 141 F.E.R.C. ¶ 61,223 (2012).

Texas Gas Transmission, LLC includes similar rulings to the above regarding the 2011 Act, outages due to acts of shippers or third parties, and the definition of force majeure.[450] Further, the FERC found that a twenty-day safe harbor period is too long in this case;[451] however, "the addition of one day to the [ten]-day [s]afe [h]rbor period would result in Texas Gas's risk sharing being in the same ball park as the risk sharing under the Safe Harbor Method for an SFV pipeline which does not allocate any fixed costs to the usage charge" because "Texas Gas' loss of the 6.7[%] of its fixed costs included in its usage charge during each day of the first [ten] days of a force majeure outage is the equivalent of providing the shippers a credit equal to 67[%] of the fixed costs included in the charges for one day of service."[452] Further, "the triggering event for whether a force majeure has occurred requiring Texas Gas to provide reservation charge credits is Texas Gas's provision of notice of a force majeure event [and not] Texas Gas's failure to deliver the [a]verage [u]sage [q]uantity."[453] The FERC clarified that the "calculat[ion of] reservation charge credits for all firm services based on (1) the shipper's average nominated quantity during the seven days immediately before the force majeure outage for services requiring nominations and (2) the shipper's actual flow quantity during the preceding seven days for services not requiring nominations"[454] requires "a further explanation of under what circumstances it is appropriate to use nominated quantities to determine reservation charge credits for [n]o [n]otice service or revise its proposal to base such credits on actual deliveries"[455] because this service does not require nominations. The FERC declined to require credits for service to secondary points because "[it] has never required pipelines to maintain sufficient capacity to give firm shippers a guaranteed right to service at secondary points."[456]

11. *Gas Transmission Northwest, LLC*, 141 F.E.R.C. ¶ 61,101 (2012).

In *Gas Transmission Northwest LLC*,[457] the FERC found that it is acceptable "to base reservation charge credits in both force majeure and non-force majeure situations on 'confirmable nominations;'" however, "any

449. *Gulf S. Pipeline Co., LP*, 141 F.E.R.C. ¶ 61,224 at PP 14-28, 48-54, 55-67, 68-70, 75-84, 89-92 (2012).

450. *Texas Gas Transmission, LLC*, 141 F.E.R.C. ¶ 61,223 (2012).

451. *Id.* at P 65.

452. *Id.* at P 67.

453. *Id.* at P 72.

454. *Id.* at P 73.

455. *Id.* at P 77.

456. *Id.* at P 90.

457. *Gas Transmission Nw., LLC*, 141 F.E.R.C. ¶ 61,101 (2012).

exemption from crediting for nominated amounts not 'confirmed' [must be] limited to events not within a pipeline's control."[458] Also, making reservation charge credits the sole remedy for the non-delivery of gas is not just and reasonable,[459] and "legislative, administrative[,] or judicial action which has been resisted in good faith by all reasonable legal means" must be excluded from the definition of force majeure.[460]

12. *Texas Eastern Transmission, LP*, 140 F.E.R.C. ¶ 61,216 (2012).

Texas Eastern Transmission, LP is an order on rehearing and compliance filing following a prior order where the FERC directed Texas Eastern Transmission, LP (Texas Eastern) to conform its tariff to the reservation charge credits policy.[461] Texas Eastern responded that there is no "sufficient showing to support initiating an investigation under section 5 of the NGA" and "that its existing reservation charge crediting provisions are just and reasonable."[462] The FERC found that it properly required Texas Eastern to conform its tariff to the reservation charge credits policy but granted rehearing in order to allow Texas Eastern to keep a provision in its tariff authorizing it to interrupt or curtail service in order to perform routine repairs and maintenance because that provision did not address reservation charge credits.[463] However, the FERC required Texas Eastern to clarify that the provision does not authorize it to curtail service after it has been scheduled.[464]

T. Termination

In *Essar Steel Minnesota, LLC v. Great Lakes Gas Transmission LP*, the FERC dismissed a complaint arising out of an attempt by Essar Steel Minnesota (ESML), an industrial customer, to modify a firm transportation service agreement with Great Lakes Gas Transmission Limited Partnership (Great Lakes).[465] The agreement provided for service to commence on July 1, 2009, but ESML was unable to construct the steel production facility which was to have been served under the agreement by the commencement date.[466] After ESML failed to pay invoices for reservation charges applicable to the first three months during which service was to have been provided, Great Lakes sued in federal district court in Minnesota for anticipatory repudiation of the service agreement.[467]

ESML alleged in its FERC complaint that Great Lakes acted unjustly and unreasonably and in violation of its tariff and NGA section 5, by failing to

458. *Id.* at P 42.

459. *Id.* at PP 44-45.

460. *Id.* at P 46.

461. *Texas E. Transmission, LP*, 140 F.E.R.C. ¶ 61,216 at P 1 (2012).

462. *Id.* at PP 10-11.

463. *Id.* at PP 30-31.

464. *Id.* at P 33.

465. *Essar Steel Minn., LLC v. Great Lakes Gas Transmission LP*, 142 F.E.R.C. ¶ 61,194 at PP 1, 6 (2013).

466. *Id.* at P 8.

467. *Id.* at PP 5-6.

negotiate in good faith to reach a mutually agreeable resolution of the issues occasioned by ESML's inability to construct its facility by the anticipated date.[468] ESML contended that Great Lakes had "accommodated good faith requests in other circumstances" and that its failure to do so in this instance was due to a desire to preserve capacity for an affiliate.[469] Finally, ESML asserted that Great Lakes had "not formally terminated or suspended service" but was denying ESML its rights under the tariff.[470] The FERC agreed with Great Lakes' position that the complaint was "essentially duplicative of the contractual dispute already before the federal district court"[471] and declined to exercise jurisdiction over the complaint based upon the FERC's traditional three-pronged *Arkla* analysis.[472]

III. INFRASTRUCTURE

On September 20, 2012, FERC Chairman Wellinghoff announced the creation of the new Office of Energy Infrastructure Security (OEIS) to focus on potential cyber-attacks and physical security risks to jurisdictional energy facilities.[473]

The OEIS will focus on "identifying, communicating, and mitigating potential cyber and physical security threats" and vulnerabilities; providing "assistance, expertise[,] and advice to other federal and state agencies, jurisdictional utilities[,] and Congress;" and participating in "interagency and intelligence-related coordination and collaboration efforts with appropriate federal [and] state agencies and industry representatives on cyber and physical security matters related to [FERC]-jurisdictional energy" facilities, including, but not limited to "conduct[ing] outreach with private sector owners, users[,] and operators of energy delivery systems, regarding identification, communication and mitigation of cyber and physical threats to FERC-jurisdictional energy" facilities.[474]

A. Pipeline Certificate Applications

In *Dominion Transmission, Inc*., the FERC approved the Allegheny Storage Project filed by Dominion Transmission Inc. (DTI) under section 7(c) of the

468. *Id.* at P 10.

469. *Id.*

470. *Id.*

471. *Id.* at P 21.

472. *Id*. (citing *Portland Gen. Elec. Co.*, 72 F.E.R.C. ¶ 61,009, at p. 61,021 (1995); *Arkansas La. Gas Co. v. Hall*, 7 F.E.R.C. ¶ 61,175, at p. 61,322 (1979), *reh'g denied*, 8 F.E.R.C. ¶ 61,031 (1979)). Using the three-pronged analysis, the FERC elaborated that:

> (1) it had no special expertise in "straight-forward contractual matters," (2) there was no need for uniformity of interpretation in dealing with a dispute over damages resulting from termination of an agreement, and (3) the issue of whether there had been an anticipatory repudiation of the service agreement is not important to the FERC's regulatory responsibilities.

Id.

473. Jon Wellinghoff, Chairman, FERC, Statement of New FERC Office to Focus on Cyber Security (Sept. 20, 2012), *available at* http://www.ferc.gov/media/statements-speeches/wellinghoff/2012/09-20-12-wellinghoff.asp.

474. *Id.*

Natural Gas Act[475] to expand transportation and storage capacity on the system.[476] The FERC found that DTI's "executed long-term agreements with three customers, including two local distribution companies, for the full capacity [proposed]," constituted "significant evidence of demand for the project" adequate to satisfy the statutory standard.[477] The FERC further found that the project would provide significant benefits with minimal adverse effects on "existing shippers, other pipelines and their captive customers, landowners, and surrounding communities."[478]

The FERC denied requests for a trial-type hearing, finding no material issue of fact that could not be resolved based on the written record.[479] The FERC also rejected requests to consolidate the proceeding with a separate application DTI to expand the boundary of a storage facility that was a component of the project.[480] The FERC had previously approved the storage boundary expansion.[481] The boundary expansion left "[t]he total capacity of the storage field . . . unchanged."[482] The boundary change had no impact on the separate expansion proposal.[483]

The FERC also approved DTI's proposed incremental rates.[484] The FERC specifically approved the use of DTI's pre-tax rate of return from its previous section 4 rate proceeding, even though that proceeding had concluded fifteen years earlier.[485] The FERC also approved use of a lower return rate for the allowance for funds used during construction (AFUDC), stating that AFUDC is intended to recover short term borrowing and equity costs while the project is under construction, while rates are intended to recover project costs over the life of the facility.[486]

The FERC rejected arguments that some of the proposed facilities were unnecessary.[487] Protestors contended that certain shippers intended to use their capacity for only a portion of the year.[488] The FERC reiterated that all of the capacity of the proposed project is subscribed under precedent agreements, which constitutes "strong evidence of market demand."[489] The FERC stated that "it is Commission policy to not look behind precedent or service agreements to make judgments about the needs of individual shippers."[490]

475. 15 U.S.C. § 717f(c) (2012).

476. *Dominion Transmission, Inc*., 141 F.E.R.C. ¶ 61,240 at P 1 (2012).

477. *Id.* at P 23.

478. *Id.* at P 21.

479. *Id.* at P 25.

480. *Id.* at PP 28-29

481. *Id.* at P 29.

482. *Id.*

483. *Id.*

484. *Id.* at P 40.

485. *Id.* at P 41.

486. *Id.* at P 42.

487. *Id.* at P 66.

488. *Id.* at P 65.

489. *Id.* at P 66 (citing *Transcontinental Gas Pipe Line Co.*, 141 F.E.R.C. ¶ 61,091 (2012)).

490. *Id.* (citing *Certification of New Interstate Natural Gas Pipeline Facilities*, 88 F.E.R.C. ¶ 61,227, at p. 61,744 (1999) (citing *Transcontinental Gas Pipe Line Corp.*, 82 F.E.R.C. ¶ 61,084, at p. 61,316 (1998))).

The FERC also rejected contentions by protestors that that DTI attempted to evade the Council of Environmental Quality (CEQ) regulations by improperly "segmenting" the Allegheny Storage Project from another project for which DTI filed a separate application.[491] Joint consideration of multiple projects in the same environmental analysis is required, if they "(1) automatically trigger other actions which may require an environmental impact statement; (2) cannot or will not proceed unless other actions are taken previously or simultaneously; or (3) are interdependent parts of a larger action and depend on the larger action for their justification."[492] The FERC held that while the projects "involve[d] the same storage pool, they [were] not 'connected' actions under the CEQ regulations," finding that (1) neither project depended on the other for approval, and (2) one of the two projects did not involve any construction of facilities or ground disturbance and accordingly would have minimal environmental impact.[493]

In a separate order, the FERC granted a certificate to DTI that authorized "the construction and operation of two discrete expansion projects in Pennsylvania and New York on DTI's existing system."[494] The Tioga Area Expansion Project added 270,000 Dth/d of firm capacity for two shippers.[495] The Sabinsville to Morrisville Project involved installation of "3.56-miles of new 24-inch diameter pipeline along with new piping facilities in Tioga County, Pennsylvania," to "enable [DTI] to establish a new receipt point for Tennessee Gas Pipeline Company, L.L.C.'s . . . existing transportation service on [DTI's]."[496]

The FERC evaluated the environmental impacts of both projects in a single environmental assessment (EA), even though the projects were not inter-dependent, and the FERC did not consolidate the proceedings involving the projects.[497] The use of a single EA was based on the geographic proximity of the projects to each other.[498]

The FERC approved the presumption of roll-in of the costs and revenues of the Tioga Area Expansion Project, subject to review in DTI's next general section 4 rate case.[499] The FERC found that the projected revenues would exceed the costs for the first three years of the project, benefiting DTI's existing shippers.[500] The FERC rejected arguments that granting the presumption was premature, stating that "it is Commission policy to make a predetermination as to the appropriate pricing for new facilities in the certificate proceeding in which

491. *Id.* at PP 79, 83.
492. *Id.* at P 80; *see also* 40 C.F.R. §1508.25(a)(1)(i)-(iii) (2013).
493. 141 F.E.R.C. ¶ 61,240, at P 83.
494. *Dominion Transmission, Inc.*, 142 F.E.R.C. ¶ 61,179 at PP 1, 3 (2013).
495. *Id.* at P 1.
496. *Id.*
497. *Id.* at P 2.
498. *Id.*
499. *Id.* at P 24.
500. *Id.*

their construction is authorized, in order to provide certainty regarding the potential economic impacts of a project before construction begins."[501]

In contrast, the FERC approved the proposed incremental monthly firm reservation surcharge for the Sabinsville to Morrisville Project.[502] Tennessee Gas Pipeline Company, L.L.C. (Tennessee), the shipper, agreed to this surcharge in order "to move its existing receipt point to a new [measurement and regulating (M&R)] station" created by the construction.[503] The project created no new capacity.[504] The FERC held that this rate structure would prevent subsidization by existing shippers.[505] Tennessee and DTI entered into a negotiated rate agreement covering this service.[506] The FERC directed Tennessee to file the negotiated rate agreement prior to commencement of service.[507]

The FERC issued a Presidential Permit to El Paso Natural Gas Company (El Paso) under section 3 of the NGA[508] and a certificate under NGA section 7,[509] authorizing El Paso to site, construct, and operate pipeline facilities at the international boundary to export gas to Mexico.[510] The Norte Crossing comprised 1,500 feet of 36-inch pipeline with a maximum export capacity of 366,000 Mcf/d.[511] The facilities would transport gas for delivery to "Tarahumara Pipeline at the United States/Mexico border underneath the Rio Grande River" to serve a power plant in Mexico.[512] The FERC found that the proposed export facility met the standard under section 3, which requires approval unless the proposed export facilities are not consistent with the public interest.[513] The FERC found the export was needed to meet future power generation demand in northern Mexico, as evidenced by the plans of the Mexican Comision Federal de Electricidad to build five new power plants in that region.[514] In addition, the approval of the export "reduc[ed] barriers to foreign trade and stimulat[ed] the flow of goods and services between the United States and Mexico," consistent with the North American Free Trade Agreement (NAFTA).[515]

In *El Paso Natural Gas Co.*, the FERC approved the Willcox Lateral 2013 Expansion Project to make additional gas deliveries to Mexico for export.[516] El Paso proposed to relocate compression facilities from its mainline to the Willcox Lateral, to increase the capacity of the lateral by 90,000 Dth/d and increase the

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501. *Id.* (citing *Colorado Interstate Gas Co.*, 94 F.E.R.C. ¶ 61,382, at p. 62,433 (2001); *Certification of New Interstate Natural Gas Pipeline Facilities*, 88 F.E.R.C. ¶ 61,227, at p. 61,750 (1999)).

502. *Id.* at PP 26-27.

503. *Id.* at PP 27-28.

504. *Id.* at P 27.

505. *Id.*

506. *Id.* at P 28.

507. *Id.* at P 27.

508. 15 U.S.C. § 717b (2012).

509. *Id.* § 717f.

510. *El Paso Natural Gas Co.*, 140 F.E.R.C. ¶ 61,174 at P 1 (2012).

511. *Id.* at P 4.

512. *Id.*

513. *Id.* at P 10.

514. *Id.* at PP 3, 10.

515. *Id.* at P 10.

516. *El Paso Natural Gas Co.*, 141 F.E.R.C. ¶ 61,026 at PP 1-2 (2012).

MAOP on the lateral, to deliver gas to northern Mexico for new power generation.[517] The FERC approved the modification to the border crossing facilities under NGA section 3, citing increased gas demand to serve power generators in northern Mexico.[518] The amended presidential permits would increase the combined maximum daily export capacity from 208,000 Mcf/d to 446,000 Mcf/d.[519]

However, the FERC denied El Paso's request to roll the costs of the expansion project into the "existing incremental Willcox Lateral rates."[520] While El Paso calculated that the recourse rate for the expansion service would be lower than the recourse rate for the Wilcox Lateral as a whole, which ordinarily would support roll-in, El Paso had entered into discount rate agreements with the expansion shippers that would cause El Paso to under-recover the expansion project's cost of service for the first three years of service.[521] The FERC accordingly denied roll-in.[522]

The FERC found further that expansion would have minimal adverse effects on landowners because El Paso held title to the land needed for the reconfigured compression.[523] The FERC approved El Paso's proposal not to charge expansion shippers for lost and unaccounted-for (LAUF) gas, because those shippers are subject to the mainline LAUF rate.[524]

In *Hamilton v. El Paso Natural Gas Co.*, the FERC dismissed in part a complaint by a landowner contending that the lowering of a 720-foot pipe segment for burial at a greater depth violated the pipeline safety regulations in title 49 of the Code of Federal Regulations.[525] The FERC found that the Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) had primary responsibility to address safety issues and that PHMSA had previously reviewed the allegation, determined no further action was necessary, and closed the matter.[526]

The FERC further rejected contentions that El Paso's reburial of the pipeline segment to a greater depth constituted replacement or miscellaneous rearrangement of the pipeline subject to 18 C.F.R. section 2.55 (facilities replacement) or 157.208 (miscellaneous rearrangement).[527] The FERC found that El Paso's actions were "routine operation and maintenance" authorized under El Paso's original certificate.[528] The FERC added, however, that El Paso had a continuing obligation to maintain the pipeline pursuant to FERC regulations and NGA section 7(h), which sets forth the FERC's eminent domain

517. *Id.* at PP 7, 11.
518. *Id.* at PP 26-27.
519. *Id.* at P 26.
520. *Id.* at P 17.
521. *Id.*
522. *Id.*
523. *Id.* at P 19.
524. *Id.* at P 23.
525. *Hamilton v. El Paso Natural Gas Co.*, 141 F.E.R.C. ¶ 61,229 at PP 1, 5 (2012).
526. *Id.* at P 19.
527. *Id.* at PP 22-23; *see also* 18 C.F.R. §§ 2.55(b), 157.208(a) (2013).
528. *Id.* at P 23.

power.[529] The FERC found that "the routine operation and maintenance requirement under the original certificate carries with it the basic obligation to restore the land affected to its original condition."[530]

The FERC also rejected El Paso's contentions that an earlier arbitration proceeding barred the complaint under the doctrines of res judicata, collateral estoppel, and laches.[531] The FERC held that the private action could not bar its authority to enforce its statutory authority and that the timing of the proceeding and remedy worked no hardship on El Paso.[532] The FERC also rejected arguments that the federal statute of limitations under 28 U.S.C. § 2462 barred any penalty or fine as non-germane because the FERC had not imposed a penalty or fine.[533]

The FERC issued a series of orders addressing the application of Millennium Pipeline Company, L.L.C. (Millennium) under NGA section 7(c) and part 157 to construct and operate a compressor station and ancillary facilities in the Town of Minisink, New York, to transport an additional 225,000 Dth/d to Algonquin Gas Transmission LLC (Algonquin) at Ramapo, New York.[534] The FERC approved the proposed project by a 3-2 vote, with Chairman Wellinghoff and Commissioner LaFleur dissenting in separate statements.[535] Local residents and landowners, as well as state and local agencies, expressed numerous environmental concerns regarding the proposed project, ranging from air emissions, noise, and potential harm to wildlife habitats.[536]

The principal point of disagreement centered on an alternative that would have involved construction of a smaller compressor station adjacent to Millennium's existing Wagoner Meter Station, a site previously used for "compression activities," combined with replacement pipeline.[537] The majority found, however, that moving the compressor station as proposed in the alternative would require replacement of a significant portion of the pipeline to make delivery of the additional volumes hydraulically feasible.[538]

529. *Id*. at PP 24-26 (citing 15 U.S.C. § 717f(h) (2012); 18 C.F.R. §§ 157.14(a)(9)(vi), 380.15(b), 380.12(i)(5)).

530. *Id.* at P 29. A site inspection revealed that although El Paso generally had restored the right-of-way to the pre-excavation grade, the soil had not been compacted to the pre-excavation level, potentially interfering with irrigation equipment. *Id.* at PP 32-33. The FERC directed El Paso to further compact the soil to the pre-excavation level. *Id.* at P 34.

531. *Id.* at PP 38-40.

532. *Id.*

533. *Id.* at P 41 (citing 28 U.S.C. § 2462 (2012)).

534. *Millennium Pipeline Co.*, 140 F.E.R.C. ¶ 61,045 at PP 1, 4 (2012), *stay of notice to proceed denied*, 141 F.E.R.C. ¶ 61,022, *order denying and dismissing requests for reh'g, denying request to reopen and supplement the record, and denying requests for stay*, 141 F.E.R.C. ¶ 61,198, 141 F.E.R.C. ¶ 61,198, *on reh'g*, 142 F.E.R.C. ¶ 61,077 (2013).

535. 140 F.E.R.C. ¶ 61,045 (Wellinghoff, Chairman, dissenting) (stating that there are preferable alternatives to the proposal); *id.* (LaFleur, Comm'r, dissenting) (stating that the adverse effects of the compressor facility outweigh the public benefit, especially given that there is an alternative).

536. *Id.* at P 23.

537. *Id.* at PP 26-27; *id.* (LaFleur, Comm'r, dissenting).

538. *Id.* at P 27.

The FERC rejected attempts by a group of residents to reopen the record to consider an engineering analysis prepared by a consultant to the group.[539] Despite its rejection of the motion to reopen, the FERC also analyzed and rejected the consultant's conclusion that the project would result in "extremely high actual gas velocities" that would exceed "prudent design standards" and safety margins intended to prevent ruptures.[540] The FERC found, however, that the consultant's assumptions and analysis were flawed.[541] The FERC accordingly found that the citizens' group did not show "extraordinary circumstances" to support reopening of the record.[542]

The FERC approved an application by Questar Pipeline Company (Questar) to construct and operate the Uinta Basin Liquids Project, which involved construction and modification of facilities to enable Questar to transport higher BTU gas produced in the Uinta Basin to a third-party straddle processing plant for liquids removal.[543] Several parties protested on the grounds that the modifications would degrade existing firm services by changing direction of flow and requiring the routing of their transportation service through a compressor station.[544] The FERC held the routing through a compressor station would not make service less reliable because "compression is an integral component of the pipeline system of which it is a part."[545] The FERC further pointed out that the application did not modify existing shippers' service agreements with Questar, which define the services provided.[546]

The FERC further ruled that a project impact that resulted in stranded facilities on a gatherer's interconnected system did not constitute an adverse impact under the Certificate Policy Statement.[547] The gatherer contended that by re-routing gas through on-system compression, the project would render the gatherer's off-system compression unnecessary.[548] The FERC rejected the argument as speculative, stating further that while it "does have an obligation to ensure fair competition, it does not protect pipeline competitors from the effects of competition."[549] The FERC found that Questar had a valid business reason for undertaking the project to transport new supplies to a straddle processing plant and that the protestor's contention that Questar was in breach of a contract with the gatherer should be resolved in "an appropriate forum," i.e. a court.[550] In addition, the FERC found that the projected revenues for the project exceeded the costs, stating that "it is longstanding Commission policy to include only the

539. 141 F.E.R.C. ¶ 61,198 at PP 12-13.

540. *Id.* at P 75.

541. *Id.* at P 76.

542. *Id.* at PP 13, 80; *see also* 142 F.E.R.C. ¶ 61,077 at PP 8-10 (2013).

543. *Questar Pipeline Co.*, 140 F.E.R.C. ¶ 61,040 at P 1 (2012), *reh'g denied*, 142 F.E.R.C. ¶ 61,127 (2013).

544. 142 F.E.R.C. ¶ 61,127 at P 8.

545. *Id.* at P 9.

546. *Id.* at P 11.

547. *Id.* at P 17.

548. *Id.* at P 16.

549. *Id.* at PP 16-17 (citing *Questar Pipeline Co.*, 140 F.E.R.C. ¶ 61,040 at P 62 (2012); *Certification of New Interstate Natural Gas Pipeline Facilities*, 88 F.E.R.C. ¶ 61,227, at p. 61,748 (1999)).

550. *Id.* at P 17.

costs of the facilities being constructed in the roll-in analysis, notwithstanding the fact that the provision of the new or expanded services may also rely upon existing facilities."[551]

The FERC approved the MPP Project proposed by Tennessee Gas Pipeline Company, L.L.C. (Tennessee) to transport an additional 240,000 Dth/d through new facilities to be constructed in Pennsylvania.[552] Tennessee entered into contracts at the system rates with two "anchor" shippers.[553] The contracts provided those shippers specific rights beyond those found in the pro forma agreement in Tennessee's tariff, including:

> (1) a contractual right-of-first refusal (ROFR); (2) the right to . . . [reduce the duration of the] . . . primary term . . . [and revenue requirement]; (3) the right to amend the shipper's primary delivery points at the discounted rates; (4) an option to acquire certain unsubscribed project transportation capacity; and (5) an option to reduce the shippers' respective transportation quantities on a pro-rata basis in the event that the in-service date for . . . [a separate but related project] is delayed.[554]

The recitals in the service agreements also referred to the project.[555] The FERC found that the provisions were "non-conforming" under section 154.112(b) of the regulations but held further that the non-conforming provisions were acceptable.[556]

The FERC rejected contentions that an up-front presumption of rolled-in rates was inappropriate, finding that Tennessee had shown that projected revenues would exceed costs.[557] The FERC found that an up-front ruling is appropriate "in order to provide the industry with as much rate certainty as is possible."[558]

The FERC rejected a request to "analyze the software used in pipeline pigs" based on concerns that the software may not be properly calibrated to detect any problems that pose risks to humans, wildlife, and the environment.[559] The FERC stated that PHMSA regulated those maintenance operations under its regulations.[560] The FERC ruled further that the development of shale gas production related to the project, "when evaluated with other past, present, and reasonably foreseeable projects in the area, would not result in significant cumulative impacts," as found in the EA.[561] The FERC rejected assertions that the project would lead to exportation of natural gas as speculative.[562]

In *Transcontinental Gas Pipe Line Co., LLC*, the FERC approved the Northeast Supply Link Project proposed by Transcontinental Gas Pipe Line

551. 140 F.E.R.C. ¶ 61,040 at P 39.
552. *Tennessee Gas Pipeline Co.*, 140 F.E.R.C. ¶ 61,120 at P 1 (2012).
553. *Id.* at P 5.
554. *Id.* at P 21.
555. *Id.* at P 22.
556. *Id.* at PP 25-26; 18 C.F.R. § 154.112(b) (2013).
557. 140 F.E.R.C. ¶ 61,120 at PP 19-20.
558. *Id.* at P 19 (citing *Pricing Policy for New and Existing Facilities Constructed by Interstate Natural Gas Pipeline*, 71 F.E.R.C. ¶ 61,241, at p. 61,915 (1995)).
559. *Id.* at P 29.
560. *Id.*
561. *Id.* at P 30.
562. *Id.* at P 31.

Company, LLC (Transco), to construct and increase the MAOP of facilities in Pennsylvania, New Jersey, and New York and increase the MAOP to provide 250,000 Dth/d of incremental firm service from supply interconnections in Pennsylvania to its 210 Market Pool in New Jersey and delivery points in New York City.[563] The incremental capacity was fully subscribed under firm long-term contracts at negotiated rates.[564] Transco developed an incremental cost of service for the project.[565] The FERC rejected contentions that Transco's showing of need was inadequate because it purportedly changed the data sources it cited.[566] The FERC found that the precedent agreements for the full proposed incremental capacity constituted "strong evidence of market demand," consistent with the requirements of the 1999 Certificate Policy Statement.[567] The FERC found that there was no reason for it to question the contract between Transco and its affiliate Williams Gas Marketing in the absence of affiliate abuse under the Standards of Conduct.[568]

The FERC approved Transco's proposed incremental recourse rate of \$0.79074/Dth, which was considerably higher than the generally applicable recourse rate of \$0.11892/Dth.[569] The FERC rejected contentions that Transco should allocate the costs of existing facilities to the incremental services, stating that an individual certificate proceeding is not an appropriate forum for addressing allocation of existing costs.[570] The FERC indicated that allocation issues could be addressed in a future rate case.[571]

Landowners and environmental organizations raised a range of environmental and land issues.[572] Among other things, commenters challenged the FERC's use of an EA instead of an EIS.[573] The FERC based its approval on an EA, holding that its "years of experience with NEPA implementation for pipeline projects" indicated that the Northeast Supply Project did not constitute a "major" project for which an EIS would automatically be prepared.[574] The project included relatively short looping facilities within or adjacent to existing rights-of-way, one new compressor station sited in an industrial area, an uprate to one pipeline segment, and modification to existing above-ground facilities, principally at or in the vicinity of delivery points.[575] The FERC further agreed with Staff's conclusion, based on the EA, that the project would not constitute a

563. *Transcontinental Gas Pipe Line Co.*, 141 F.E.R.C. ¶ 61,091 at PP 1, 3 (2012), *reh'g*, 143 F.E.R.C. ¶ 61,132.

564. *Id.* at P 5.

565. *Id.* at P 7.

566. *Id.* at PP 19-20.

567. *Id.* at P 20 (citing *Certification of New Interstate Natural Gas Pipeline Facilities*, 88 F.E.R.C. ¶ 61,227, at p. 61,748 (1999)).

568. *Id.* at P 21; 18 C.F.R. § 358.4-.5 (2013).

569. 141 F.E.R.C. ¶ 61,091 at P 26.

570. *Id.* at P 27.

571. *Id.*

572. *Id.* at P 42.

573. *Id.* at PP 41, 43.

574. *Id.* at P 43.

575. *Id.* at P 44.

"major" action that would have a "significant" impact on the environment and accordingly did not require an EIS.[576]

Among other things, the FERC found that the project's impact on the development of the Marcellus Shale was outside the scope of the EA because "the exact location, scale, and timing of future exploration and production activities are unknown," and declined to consider the cumulative impact of Marcellus Shale development because the impact is neither "sufficiently causally related" to the project nor "reasonably foreseeable."[577] The CEQ regulations require agencies to consider direct, indirect, and cumulative impacts.[578] "Direct effects" are "caused by the action and occur at the same time and place;" "indirect effects" are "caused by the action and are later in time or farther removed in distance, but are still reasonably foreseeable;" and the "cumulative impact" is the "impact on the environment that results from the incremental impact of the action when added to other past, present, and reasonably foreseeable future actions."[579] The FERC found that the environmental effect of the project did not have the "reasonably close causal relationship" with Marcellus production that would require evaluation in the EA.[580] The FERC also rejected arguments that its use of an EA established a precedent that could bind it in future cases, stating that "the decision on whether to prepare an EA or an EIS is an individual one, made on the basis of the particular circumstance presented by each individual proposal."[581]

B. Storage Projects

1. *Petal Gas Storage, L.L.C.*, 142 F.E.R.C. ¶ 61,119 (2013).

The FERC granted the joint application of Petal Gas Storage, L.L.C. (Petal) and Hattiesburg Industrial Gas Sales, L.L.C. (Hattiesburg) for "certificate authorization for Petal to acquire and consolidate into its existing interstate natural gas storage operations the non-jurisdictional storage facilities owned and operated by Hattiesburg."[582] Petal and Hattiesburg proposed to "merge the facilities and operations . . . owned and operated individually by Petal and Hattiesburg into a single, jurisdictional interstate natural gas storage facility to be owned and operated by Petal."[583] The applicants sought "authorization for Petal to acquire Hattiesburg's storage and pipeline facilities by inter-corporate merger and integrate all such facilities into Petal's interstate system, and for Hattiesburg to abandon its certificate of limited jurisdiction."[584] The applicants additionally requested that "Petal be authorized to continue to provide firm and

576. *Id.* at P 43.

577. *Id.* at P 45; *see also id.* at P 128-41 (citing United States Dep't of Transp. v. Public Citizen, 541 U.S. 752, 767 (2004); *Central N.Y. Oil and Gas Co.*, 137 F.E.R.C. ¶ 61,121 at P 88 (2011), *order on reh'g, clarification and stay*, 138 F.E.R.C. ¶ 61,104 (2012)).

578. *Id.* at P 51 (citing 40 C.F.R. § 1508.25 (2013)).

579. *Id.* at 127 (citing 40 C.F.R. §§ 1508.7, 1508.8(a)-(b)).

580. *Id.* at P 54 (citing *Public Citizen*, 541 U.S. at 767).

581. *Id.* at PP 44-45.

582. *Petal Gas Storage, LLC*, 142 F.E.R.C. ¶ 61,119 at PP 1, 19 (2013).

583. *Id.* at P 9.

584. *Id.* at P 10.

interruptible storage services at market-based rates using the combined facilities."[585] The FERC determined that "[a] proposal to acquire facilities with no related construction of facilities, such as [this proposal], generally does not [raise] . . . concerns related to disruptions of the environment, landowners' rights, [or] the exercise of eminent domain."[586] It found that there was no indication that the proposal would "adversely affect the quality of Petal's existing services," and further found that the applicants' proposal would "have no adverse impact on existing pipelines in the market or their customers."[587] The FERC found that "Petal may continue to charge market-based rates for its storage services" yet conditioned the finding on a requirement that "Petal notify the [FERC] of future circumstances that may significantly affect its market power status."[588]

2. *Transcontinental Gas Pipe Line Co.*, 142 F.E.R.C. ¶ 61,095 (2013).

Transcontinental Gas Pipe Line Company, LLC (Transco) filed an application to "abandon four of seven existing natural gas storage caverns at the Eminence Salt Dome Storage Field."[589] Transco experienced a catastrophic event in one cavern, which affected the integrity of three additional caverns.[590] The FERC found that the abandonment of the four caverns, "related wells, and associated surface facilities was permitted by the public convenience and necessity."[591] However, the FERC conditioned its approval of Transco's abandonment, requiring Transco to "file semi-annual reports updating its emergency activities, its investigation into the incident, and the status of its abandonment activities."[592] The FERC also directed Transco to establish a cavern integrity monitoring program and file semi-annual summary reports of the results of the monitoring.[593] Additionally, the FERC found that the "public convenience and necessity require[d] approval of Transco's request to amend its certificate authority for the Eminence Storage Field to reduce the authorized total capacity of the facility . . . and the deliverability of the facility," but denied "Transco's request for continued authority to exceed the total overall capacity of the field . . . by up to 15[%] in any one year."[594] Lastly, the FERC denied Transco's request for authority to abandon, by sale, base gas in the Eminence Storage Field.[595]

3. *Dominion Transmission, Inc.*, 141 F.E.R.C. ¶ 61,183 (2012).

The FERC granted Dominion Transmission, Inc.'s (Dominion) application for a "certificate of public convenience and necessity to establish a protective

585. *Id.* at P 12.
586. *Id.* at P 24.
587. *Id.* at PP 25-26.
588. *Id.* at P 73.
589. *Transcontinental Gas Pipe Line Co., LLC*, 142 F.E.R.C. ¶ 61,095 at P 1 (2013).
590. *Id.* at P 39.
591. *Id.*
592. *Id.* at P 42.
593. *Id.* at P 58.
594. *Id.* at P 57.
595. *Id.* at P 74.

boundary . . . around its Sabinsville Storage Pool."[596] Dominion asserted that the "buffer zone [was] needed to protect the integrity of [the] storage operations . . . from a potential breach that may be caused from hydraulic fracturing of the Marcellus Shale . . . in the vicinity of the storage pool."[597] The FERC stated that it "believes, absent evidence to the contrary, that it is important that storage fields have a buffer zone to protect the integrity of the storage field, especially in areas . . . where intensive natural gas production activities are possible."[598] It found that the buffer zone (1) would not have an adverse impact on existing customers or their services, (2) would not impact the certificated operational parameters of the storage field, and (3) would not have an adverse impact on other pipelines or their customers.[599] The FERC held that "the proposed project is necessary to ensure the integrity of the Sabinsville Pool and the reliability of storage service[s] to the benefit of all Dominion's customers" and that approval of the buffer zone "is in the public convenience and necessity."[600]

4. *Floridian Natural Gas Storage Co.*, 140 F.E.R.C. ¶ 61,167 (2012).

The FERC approved an application by Floridian Natural Gas Storage Company, LLC (Floridian) to amend its certificate for a liquid natural gas (LNG) storage facility near Indiantown, Florida (Storage Project), to utilize the truck loading station for delivering LNG "into trucks during the normal course of business, instead of only during emergency situations."[601] Additionally, the FERC ordered Floridian to file a revised market power analysis, based on the approved delivery capacity increase, when it files tariff sheets.[602] The FERC originally granted a certificate for the Storage Project on August 29, 2008, wherein the authorized facilities were to include a fully functional truck loading station initially anticipated for use in emergency situations only.[603] Due to increased demand for LNG on a regular basis for truck motor fuel and other industrial applications, Floridian requested authority to ship a maximum daily equivalent of 40 MMcf/d of natural gas as LNG via the truck loading station.[604] The FERC granted the certificate amendment as consistent with the Certificate Policy Statement, finding Floridian's proposal would not rely on subsidization from existing customers (Floridian, as a new storage company had no existing customers) and the additional send out capacity would not adversely affect existing shippers.[605]

596. *Dominion Transmission, Inc.*, 141 F.E.R.C. ¶ 61,183 at P 1 (2012).

597. *Id.* at P 4.

598. *Id.* at P 22.

599. *Id.* at P 21.

600. *Id.* at P 24.

601. *Floridian Natural Gas Storage Co.*, 140 F.E.R.C. ¶ 61,167 at P 1 (2012).

602. *Id.* at P 67.

603. *Id.* at P 3; *see also Floridian Natural Gas Storage Co.*, 124 F.E.R.C. ¶ 61,214 (2008).

604. 140 F.E.R.C. ¶ 61,167 at PP 6-7. Floridian noted there were no new facilities requested in its application. *Id.* at PP 1, 15.

605. *Id.* at PP 13-14.

5. *D'Lo Gas Storage, LLC*, 140 F.E.R.C. ¶ 61,182 (2012).

The FERC granted a certificate to D'Lo Gas Storage, LLC (D'Lo Gas) to "construct and operate a salt dome natural gas storage facility and associated pipeline facilities in Simpson County, Mississippi."[606] The FERC also granted D'Lo Gas's request for market-based rate authority and its request for waivers of certain filing, accounting, and reporting requirements.[607] D'Lo Gas proposed to construct and operate three new salt dome storage caverns—with a combined project working gas capacity of 24 Bcf—and 5.4 miles of pipeline—with a total receipt and delivery capacity of 800 MMcf/d—to interconnect the facility with three interstate pipelines.[608] The FERC found D'Lo Gas's proposal was consistent with the Certificate Policy Statement because it would not rely on subsidization from existing customers (D'Lo Gas was a new storage company without existing customers) and the proposal would not adversely affect existing pipelines or storage providers in the competitive "Gulf Coast Production Area."[609] Further, the FERC determined that D'Lo Gas did not possess market power in the geographic market (encompassing 40 other competing natural gas storage facilities) under both the Herfindahl-Hirschman Index and "bingo card" analysis and therefore granted D'Lo Gas authority to "charge market-based rates for all firm and interruptible storage, hub, and wheeling services."[610] Finally, the FERC granted all of D'Lo Gas's requests for waivers of certain filing, accounting, and reporting requirements, except those relating to the Annual Charge Assessment.[611]

C. LNG Projects

1. *Cheniere Creole Trail Pipeline, L.P.*, 142 F.E.R.C. ¶ 61,137 (2013).

In *Cheniere Creole Trail Pipeline, L.P.*, the FERC issued a certificate pursuant to NGA section 7(c)[612] authorizing Cheniere Creole Trail to add new compression and related facilities on its interstate pipeline system.[613] The purpose of the additional compression was to enable bi-directional natural gas flow on the pipeline for delivery of domestic natural gas to the Sabine Pass Liquefaction Project at the Sabine Pass LNG terminal for eventual export.[614] The FERC approved the application over the objections of the Sierra Club, which argued that the proposed project would lead to increased natural gas production, particularly from shale, which would have adverse impacts on the environment.[615] The FERC found that adverse impacts which might result from additional gas production were not a "reasonably foreseeable" effect of

606. *D'Lo Gas Storage, LLC*, 140 F.E.R.C. ¶ 61,182 at PP 1-2 (2012).
607. *Id.* at PP 2, 12.
608. *Id.* at PP 4, 6-7.
609. *Id.* at PP 18, 26, 34; *see also Certification of New Interstate Natural Gas Pipeline Facilities*, 88 F.E.R.C. ¶ 61,227 (1999).
610. *Id.* at PP 34-40.
611. *Id.* at PP 41-44.
612. 15 U.S.C. § 717f(c) (2012).
613. *Cheniere Creole Trail Pipeline, L.P.*, 142 F.E.R.C. ¶ 61,137 at P 1 (2013).
614. *Id.* at P 5.
615. *Id.* at PP 20, 54.

approving Cheniere Creole Trail's certificate application within the meaning of the applicable regulations and, thus, need not be considered in evaluating the application.[616]

2. *Cameron LNG, LLC*, 140 F.E.R.C. ¶ 61,018 (2012).

On July 11, 2012, the FERC issued an order under section 3 of the NGA[617] authorizing Cameron LNG, LLC (Cameron) to "construct and operate facilities to re-liquefy boil-off gas . . . at [Cameron's] existing [LNG terminal] in . . . Louisiana."[618] Cameron explained that the new facilities would ensure that Cameron had sufficient LNG in each tank to keep the in-tank pumps submerged, so that the LNG storage tanks would remain in a constant cryogenic state.[619] Cameron explained that, because of lower-than-projected LNG imports, it had been required to purchase LNG cargoes to ensure an operationally sufficient quantity of LNG in the storage tanks.[620] The FERC concluded that Cameron's proposal would "increase the efficiency and economical operation of the terminal," and eliminate the need to purchase LNG cargoes for operational purposes.[621] Further, neither landowners nor Cameron's LNG customers would be adversely affected by the project.[622] The FERC found, therefore, that with the environmental conditions adopted in the order, Cameron's proposal was not inconsistent with the public interest under NGA section 3.[623]

616. *Id.* at P 55 (citing 40 C.F.R. § 1508.8 (2012); *City of Shoreacres v. Waterworth*, 420 F.3d 440, 453 (5th Cir. 2005)).

617. 15 U.S.C. § 717b.

618. *Cameron LNG, LLC*, 140 F.E.R.C. ¶ 61,018 at P 1 (2012).

619. *Id.* at PP 4-5.

620. *Id.* at P 4.

621. *Id.* at P 11.

622. *Id.* at P 12.

623. *Id.*

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