

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 U.S. Courts of Appeals in the area of natural gas regulation between July 1, 2011 and June 30, 2012.*

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* The committee is grateful to the following members for their contributions to this report: Daniel Archuleta, Christopher Barr, Ryan Collins, James Costan, Lisanne Crowley, Kevin Downey, Kevin Frank, Jason Gray, Thomas Hirsch, John McCaffrey, Mustafa Ostrander, Tania Perez, Julie Pradel, Randall Rich, Peter Ripley, Alyssa Schindler, Andrew Soto, and Elizabeth Teuwen.

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I. RULEMAKING ACTIONS

A. *Affiliates Rules*

In Order No. 894, the FERC revised its open access regulations regarding participation in an open season that employs a pro-rata method of allocation.¹ The amended regulation prohibits a participant in the open season “from using multiple affiliates to secure a larger allocation of capacity than it could acquire” independently “unless each affiliate has an independent business reason for submitting a bid.”²

“Before submitting a bid, [an] affiliate must decide whether and how much of the subject capacity it needs in order to accomplish its own business objectives and it should maintain some record of the basis for its determination.”³ The FERC noted that it is the responsibility of every affiliate, and “not the pipeline conducting the open season,” “to ensure that it has an independent business reason for submitting a bid.”⁴ Without comprehensively listing the circumstances under which it would find that an independent business reason existed, the FERC provided some examples,⁵ and stated that it may assess the use to which an entity puts “its awarded capacity, such as subsequently releasing the capacity to an affiliate on a long-term basis, as a factor in the determination of whether the entity in fact had an independent business reason to obtain the capacity.”⁶ The FERC declined to specify a particular documentation obligation.⁷

The Final Rule eschews a *per se* restriction against affiliates participating in an open season who “release any capacity obtained in that open season pursuant to a *pro rata* allocation to any [other] affiliate.”⁸ Rather, “an affiliate who legitimately obtains capacity in an open season for its own independent business purposes should be permitted to release that capacity to any entity under the normal capacity release rules applicable to all other shippers.”⁹

1. Order No. 894, *Bidding by Affiliates in Open Seasons for Pipeline Capacity*, 126 F.E.R.C. STATS. & REGS. ¶ 31,325 (2011), 76 Fed. Reg. 72,301 (2011) (to be codified at 18 C.F.R. pt. 284) [hereinafter Order No. 894].

2. *Id.* at PP 11, 21.

3. *Id.* at P 25.

4. *Id.* at P 26.

5. *Id.* at PP 23-24. For example separate affiliates serving power generation facilities, production assets and marketing needs might all have independent business needs and could submit bids in for the same capacity in a pro rata allocation setting. *Id.*

6. *Id.* at P 33.

7. *Id.* at P 25.

8. *Id.* at P 1.

9. *Id.* at P 33.

B. Financial Forms

In Order No. 710-C,¹⁰ the FERC generally denied rehearing and reaffirmed the findings made in Order No. 710-B, which revised the “financial forms, statements, and reports for natural gas companies, contained in FERC Form Nos. 2, 2-A, and 3-Q.”¹¹ Following consideration on remand of the regulations from the United States Court of Appeals for the District of Columbia Circuit,¹² the goal of Order No. 710-B had been “to provide greater transparency on fuel data by requiring the reporting of functionalized fuel data on pages 521a through 521c of those forms, and to include on those forms the amount of fuel waived, discounted or reduced as part of a negotiated rate agreement.”¹³ Subsequently, the Interstate Natural Gas Association of America (INGAA) filed a request for rehearing, arguing that adding the level of detail required by Order No. 710-B would increase the reporting burden.¹⁴ In response, the FERC did not reduce the additional reporting obligations, but did “distinguish between the initial start-up costs . . . as compared to the ongoing costs of reporting the information required to be reported under [Order No. 710-B] once the reporting mechanism is in place.”¹⁵ Therefore, the FERC included a revised burden estimate in Order No. 710-C.¹⁶ In response to INGAA’s concern that the new regulations required the collection of data before “pipelines [might] have the accounting systems in place,” the FERC delayed “the commencement of implementation of the filing requirements . . . until the fourth quarter period (“Q4”) of 2011.”¹⁷

C. Market Transparency

In Order No. 757, the FERC amended its regulations to eliminate 18 C.F.R. § 284.13(e) and 18 C.F.R. § 284.126(c) relating to semi-annual storage reporting requirements for interstate natural gas companies, intrastate pipelines and Hinshaw pipelines, finding the rules to be “duplicative [of] other reporting requirements.”¹⁸ In eliminating these reporting requirements, the FERC cited comments in support of the change, as well as the Executive Order that had directed executive agencies to eliminate unnecessary regulations.¹⁹ Although the FERC identified some non-duplicative data, it concluded that any benefits of this information did not outweigh the reporting burden and, should the data prove pertinent in the future, the FERC could obtain it via data requests.²⁰

10. Order No. 710-C, *Revisions to Forms, Statements, and Reporting Requirements for Natural Gas Pipelines*, 136 F.E.R.C. ¶ 61,109 at P 2 (2011) [hereinafter Order No. 710-C].

11. *Id.* at P 3 (reaffirming Order No. 710-B, *Revisions to Forms, Statements, and Reporting Requirements for Natural Gas Pipelines*, 134 FERC ¶ 61,033, 76 Fed. Reg. 4516 (2011)).

12. *See generally* American Gas Ass’n v. FERC, 593 F.3d 14 (D.C. Cir. 2010).

13. Order No. 710-C, *supra* note 10, at P 1.

14. *Id.* at P 6.

15. *Id.* at P 10.

16. *Id.* at P 30.

17. *Id.* at P 25.

18. Order No. 757, *Storage Reporting Requirements of Interstate and Intrastate Natural Gas Companies*, F.E.R.C. STATS. & REGS. ¶ 31,327 at P 1, 77 Fed. Reg. 4220 (2012) (to be codified at 18 C.F.R. pt. 284).

19. *Id.* at PP 11-12.

20. *Id.* at P 15.

In Order No. 720, the FERC issued a final rule obligating major non-interstate pipelines to post daily scheduled volume information and design capacity at certain receipt and delivery points, citing its authority and transparency goals under section 23 of the Natural Gas Act (NGA).²¹ Section 23 authorized the FERC to obtain information relevant to the statute from “any market participant.”²² Subsequently, the Texas Pipeline Association and the Railroad Commission of Texas filed petitions for judicial review of the orders. In *Texas Pipeline Association v. FERC*, the court vacated the final rule.²³ The court interpreted section 23 in the context of the FERC’s limited jurisdiction under NGA section 1(b) and found that NGA section 1(b) plainly barred the FERC from regulating the entities that section 1(b) exempted from NGA jurisdiction, including intrastate pipelines and local distribution companies.²⁴ In light of the broad exemption of intrastate pipelines from the NGA under section 1(b), the court concluded that the term “any market participant” in section 23 could not be construed to extend the FERC’s jurisdiction to intrastate pipelines.²⁵ The Fifth Circuit therefore concluded that the FERC was precluded from imposing an obligation on intrastate pipelines to file capacity and scheduling information.²⁶

II. RATES, TERMS, AND CONDITIONS OF SERVICE

A. Abandonment

The FERC denied Atlanta Gas Light Company’s (AGL) request for “rehearing to require that [Transcontinental Gas Pipe Line Co.] (Transco) reinstate Rate Schedule SS-1 Section 7(c) transportation service for [AGL] to transport storage injection and withdrawal volumes on a firm basis to and from Transco’s Leidy interconnection” where AGL had a storage service agreement with a connecting pipeline.²⁷ The FERC stated that replacing its old presumption with “the presumption that the public convenience and necessity will permit the abandonment of Part 157 services upon the expiration of the underlying service agreements” was reasonable.²⁸ The FERC said that it “is not required to find that the public convenience and necessity will not permit a particular abandonment just because an individual shipper’s private interest may be better served by continuing to receive a service that cannot be duplicated on an open-access basis.”²⁹

21. Order No. 720, *Pipeline Posting Requirements under Section 23 of the Natural Gas Act*, F.E.R.C. STATS. & REGS. ¶ 31,283 at P 1, 73 Fed. Reg. 73,494 (2008) (to be codified at 18 C.F.R. pt. 284). Section 23 of the Natural Gas Act was enacted in the Energy Policy Act of 2005, Pub. L. No. 109-58 § 316, 119 Stat. 594, (2005).

22. 15 U.S.C. § 717t-2(a)(3)(A).

23. *Texas Pipeline Ass’n v. FERC*, 661 F.3d 258, 259 (5th Cir. 2011).

24. *Id.* at 263.

25. *Id.*

26. *Id.*

27. *Transcontinental Gas Pipe Line Co.*, 137 F.E.R.C. ¶ 61,203 at P 10 (2011).

28. *Id.* at P 16.

29. *Id.*

The FERC denied rehearing of its order denying a request by several pipeline companies “to abandon their jointly-owned facilities collectively known as the Matagorda Offshore Pipeline System (MOPS) and the services provided on those facilities.”³⁰ The MOPS owners argued that the “facilities were underutilized and uneconomic to operate,” throughput had declined and was expected to continue declining, maintenance expenses were increasing, and attempts to sell the facilities and/or develop negotiated rates to recover costs had been unsuccessful.³¹ The FERC distinguished its holding in *Transco* by finding that, unlike AGL in that proceeding, “the MOPS shippers do not have reasonable transportation alternatives available.”³²

In *Tennessee Gas Pipeline Co.*, the FERC addressed the Tennessee Gas Pipeline Company (Tennessee) application to abandon certain facilities by sale to Kinetica Partners, LLC (Kinetica), and Kinetica’s request for a determination that the facilities performed a gathering function and would “be exempt from the [FERC’s] jurisdiction after the proposed abandonment.”³³ Kinetica also requested “that the FERC issue Kinetica a certificate of limited jurisdiction” if some of the facilities were not determined to be gathering.³⁴ The FERC determined that some of the facilities performed a gathering function and clarified that “Tennessee must refunctionalize” from transmission to gathering the costs of any facilities found to be gathering in its next rate case.³⁵ On rehearing, the pipeline argued that the FERC failed to address the non-physical factor criteria used in the primary function test.³⁶ The FERC denied rehearing and explained that non-physical factors are used when the other factors result in a “close call.”³⁷

The pipeline also argued that it should not be required to refunctionalize the facilities determined to be gathering because it did not request the determination.³⁸ The FERC denied rehearing and held that while it does not generally “[analyze] the primary function of facilities as they are currently operating in abandonment by sale proceedings where there are no continuity of service issues . . . where an application is protested and the proposed abandonment is by transfer” to a non-jurisdictional entity, the FERC’s policy is “to analyze the facilities as they currently exist and operate to determine whether they are performing a jurisdictional transmission function.”³⁹ Although the pipeline did not request the determination, “[the pipeline’s] abandonment application was protested by some of its shippers” so the pipeline must “shoulder the hazards incident to its action.”⁴⁰

30. *Northern Natural Gas Co.*, 137 F.E.R.C. ¶ 61,091 at P 1 (2011).

31. *Id.* at P 3.

32. *Id.* at P 18.

33. *Tennessee Gas Pipeline Co.*, 137 F.E.R.C. ¶ 61,105 at PP 1-3 (2011), *clarification granted*, 138 F.E.R.C. ¶ 61,082 (2012), *reh’g*, 138 F.E.R.C. ¶ 61,179 (2012).

34. *Tennessee Gas Pipeline Co.*, 137 F.E.R.C. ¶ 61,105 at P 2.

35. *Id.* at P 107.

36. *Tennessee Gas Pipeline Co.*, 138 F.E.R.C. ¶ 61,179 at P 8.

37. *Id.* at P 26.

38. *Id.* at P 7.

39. *Id.* at P 11.

40. *Id.* at P 14.

B. Balancing

On April 30, 2012, the FERC issued an order approving, subject to conditions, “a proposal by Gulf South Pipeline Company, LP (Gulf South) to implement daily allocations of gas on its pipeline system.”⁴¹ The FERC required Gulf South to provide real-time measurement data to point operators and their agents “no later than August 1, 2012,” and to “provide shippers equal access to its operation flow data.”⁴² The FERC allowed Gulf South “to collect overrun charges” prior to August 1, 2012 only if customers exceeded their Maximum Daily Quantity (MDQ) “by 5 percent or more for a period of ten or more days during any month,” or if the overrun occurred “during a Critical Period, Operational Flow Order (OFO), or when Gulf South implements its System Management Plan.”⁴³ The FERC also held that daily allocation overrun charges could be applied to points for which real-time measurement data was not available.⁴⁴

The FERC denied Gulf South’s request to charge an average system-wide rate for overruns and restated its policy that a pipeline’s “overrun rate should equal the 100 percent load factor equivalent of the maximum rate applicable to the contract whose MDQ was overrun.”⁴⁵ The FERC accepted Gulf South’s proposal to “allocate measured quantities at each point on its system among the shippers at that point based on Pre-Determined Allocation Agreements (PDA).”⁴⁶

The FERC did not require Gulf South to allow shippers to enter into an Operational Balancing Agreement (OBA).⁴⁷ The FERC did not require, but did permit, Gulf South to aggregate a shipper’s contracts if the contracts contained similar points, terms and rates and if the consolidation was revenue-neutral to Gulf South.⁴⁸

C. Capacity Allocation

Great Lakes Gas Transmission Limited Partnership (Great Lakes) “filed additional information” in compliance with a prior FERC order regarding the allocation of “firm shippers’ secondary out-of-path capacity and its proposed bumping provisions impacting interruptible shippers.”⁴⁹ Great Lakes proposed allocating secondary out-of-path capacity based on the highest rate paid and allowing interruptible shippers to bump other interruptible shippers if the confirmed price for subsequently nominated volumes exceeded that for already-scheduled interruptible service.⁵⁰

41. *Gulf South Pipeline Co.*, 139 F.E.R.C. ¶ 61,086 (2012).

42. *Id.* at P 20.

43. *Id.* at P 26.

44. *Id.* at P 27.

45. *Id.* at P 34.

46. *Id.* at PP 36, 55.

47. *Id.* at P 54.

48. *Id.* at PP 62, 66.

49. *Great Lakes Gas Transmission Limited Partnership*, 136 F.E.R.C. ¶ 61,070 at P 1 (2011).

50. *Id.* at P 2.

The FERC rejected Great Lakes' proposal regarding allocating secondary out-of-path capacity, holding that a "shipper's contracted price for firm service bears no relation to the value [of that capacity] to the shipper at a later time."⁵¹ The FERC determined that basing priority upon contracted price "is not consistent with allocating capacity to the highest valued use," and thus is contrary to FERC policy.⁵² The FERC directed Great Lakes to propose an alternative "allocation methodology that is consistent with [FERC] policy, such as *pro rata* allocation."⁵³ However, the FERC accepted the pipeline's proposal regarding bumping interruptible service based on price, subject to Great Lakes filing revised tariff records clarifying that bumping could not occur during the last two nomination cycles.⁵⁴

D. Capacity Release

On July 29, 2011, the FERC granted a blanket two-year waiver of its tying prohibition to Golden Pass LNG Terminal LLC (Golden Pass).⁵⁵ The waiver allows Golden Pass "to enter into short-term capacity releases with importers of spot liquefied natural gas (LNG) cargoes using [the Golden Pass Terminal]" that are tied to releases of take-away pipeline capacity "without seeking waivers for each transaction."⁵⁶

The FERC found that Golden Pass's requested waiver was justified because "importers of spot LNG cargoes will want assurance that they will have pipeline capacity to ship their re-vaporized LNG from the terminal to downstream markets, and Golden Pass Pipeline is the only way to transport gas out of the Golden Pass Terminal."⁵⁷ Additionally, the FERC found that Golden Pass's commitment "to continually post its pipeline capacity [publicly] for release" to any customer and to not place restrictions "on [any] replacement shipper's use of the pipeline capacity" provided adequate safeguards to ensure that the capacity was released in a transparent and non-discriminatory manner.⁵⁸

E. Cost Trackers

Since late 2011, the FERC issued four decisions further confirming its policy authorizing trackers by offshore pipelines to recover the costs resulting from hurricanes and other storms. First, in Opinion 516, issued on December 15, 2011, the FERC reviewed an initial decision on the hurricane cost tracking mechanism of Sea Robin Pipeline Company, LLC (Sea Robin).⁵⁹ Among other rulings, the FERC approved carrying costs accruing on any eligible costs from the later of when Sea Robin filed its hurricane tracking mechanism or when the eligible costs are incurred, as well as a four-year amortization of any associated

51. *Id.* at P 19.

52. *Id.*

53. *Id.* at P 21.

54. *Id.* at P 22.

55. *Golden Pass LNG Terminal LLC*, 136 F.E.R.C. ¶ 61,069 at P 1 (2011).

56. *Id.*

57. *Id.* at P 13.

58. *Id.* at P 14.

59. Opinion No. 516, *Sea Robin Pipeline Co., LLC*, 137 F.E.R.C. ¶ 61,201 at PP 1-2 (2011).

capital costs.⁶⁰ The FERC also made clear that the hurricane surcharge is discountable.⁶¹ The FERC avoided any *Mobile-Sierra* issues as to whether Sea Robin's shippers' contracts must be amended to allow for assessment of the hurricane surcharge; the FERC examined the shippers' discount rate agreements and found that they authorized Sea Robin's collection of the surcharge because they referred generally to applicable charges contained in Sea Robin's tariff or did not prohibit collection of surcharges.⁶² Second, on February 16, 2012, the FERC ruled that High Island Offshore System, L.L.C.'s (HIOS) proposed Storm Event cost surcharge under its tracking mechanism applied to HIOS' discount rate firm service agreements.⁶³ It reiterated that the pipeline cannot have a tariff sheet that prohibits the discounting of such a surcharge.⁶⁴ Both the *Sea Robin* and *HIOS* decisions remain pending rehearing.

Third, on June 21, 2012, the FERC also approved the hurricane surcharge mechanisms of High Point Gas Transmission, LLC and TC Offshore LLC, two new companies which had purchased the offshore pipeline systems of Southern Natural Gas Company and ANR Pipeline Company, respectively.⁶⁵

Fourth, on May 22, 2012, the FERC approved a proposed new surcharge under a tracking mechanism filed by Columbia Gas Transmission, LLC (Columbia Gas) to recover certain costs of the purchase and sale of gas to balance its system in light of declining gas receipts in the north Ohio part of its system due to the shale gas market.⁶⁶ The FERC stated that it was approving Columbia Gas' proposal, as well as a temporary waiver of "the independent functioning requirement," as an interim measure.⁶⁷ It also ruled that the pipeline's proposal did not implicate the FERC's prohibition against buy/sell arrangements.⁶⁸

F. Depreciation

In *Colorado Interstate Gas Co.*, the FERC denied rehearing of a letter order issued by the Chief Accountant that had denied the accounting treatment for the accounting entries associated with the pipeline's sale of certain facilities.⁶⁹ The primary issue on rehearing concerned Colorado Interstate Gas Company's (CIG) request to use a method of depreciation known as the "technical obsolescence appraisal method," rather than "the composite rate method (in which historic composite depreciation rates are applied to the original cost of abandoned facilities on a vintage year basis)."⁷⁰ On rehearing, CIG argued *inter alia* that its

60. *Id.* at PP 61, 63.

61. *Id.* at P 91.

62. *Id.* at PP 79, 140-41.

63. *High Island Offshore Sys., L.L.C.*, 138 F.E.R.C. ¶ 61,114 at PP 17, 19 (2012).

64. *Id.* at P 19.

65. *Southern Natural Gas Co.*, 139 F.E.R.C. ¶ 61,237 at P 173 (2012); *ANR Pipeline Co.*, 139 F.E.R.C. ¶ 61,238 at P 180 (2012).

66. *Columbia Gas Transmission, LLC*, 139 F.E.R.C. ¶ 61,141 at P 16 (2012).

67. *Id.* at P 17.

68. *Id.* at P 23.

69. *Colorado Interstate Gas Co.*, 137 F.E.R.C. ¶ 61,049 at P 1 (2011) (citing *Colorado Interstate Gas Co.*, Docket No. AC10-22-000, unpublished Letter Order issued on September 20, 2010).

70. *Id.* at P 4.

proposed accounting method was appropriate because it “accurately [measured] accumulated depreciation related to [the facilities that had been sold],” that it was consistent with accounting procedures and with other methods of depreciation, and that it did not “retroactively [alter] the composite depreciation rate.”⁷¹ The FERC found that it was not appropriate to use CIG’s proposed appraisal method when the historic depreciation was known.⁷² Instead, the FERC held that pipelines “must determine the amount of accumulated depreciation on the sale of an operating unit or system, using the actual amount of depreciation taken on the facilities transferred on a vintage year basis.”⁷³ Because use of the technical obsolescence appraisal method would have removed too much accumulated depreciation from the pipeline’s Account 108, the FERC found that its use would effectively alter the composite depreciation rates previously approved by the FERC and explained that the goal of the depreciation effort under its Gas Plant Instruction No. 5 was to determine the amount of total depreciation applicable to facilities sold as recorded on the pipeline’s books, not to use a technique appropriate to determining the fair value of the facilities sold.⁷⁴

G. Discount Adjustments for Negotiated Rate Agreements

In a matter involving Texas Gas Transmission, LLC (Texas Gas), the FERC outlined the history and application of its policies regarding the conditions a pipeline must satisfy in order to obtain a discount-type adjustment for negotiated rate transactions in a rate case.⁷⁵ This order largely affirms and consolidates existing law and adds clarifications that serve to harmonize the FERC’s policy developed in numerous cases over the last fifteen years.

H. Fuel

On March 30, 2012, the FERC issued an order approving Columbia Gulf Transmission Company’s (Columbia Gulf) February 29, 2012 proposal to revise its transportation retainage rates.⁷⁶ Columbia Gulf had also proposed to remove from its transportation retainage adjustment fuel that is consumed pursuant to a negotiated rate agreement.⁷⁷ The FERC approved Columbia Gulf’s proposal, rejecting a claim that the proposed exclusion of fuel associated with the negotiated rate agreement was improperly calculated.⁷⁸

On March 30, 2012, the FERC issued an order addressing Rockies Express Pipeline, LLC’s (REX) 2012 annual fuel filing, as well as REX’s request for rehearing of a March 30, 2011 order⁷⁹ on REX’s 2011 annual fuel filing.⁸⁰ The

71. *Id.* at P 6.

72. *Id.* at P 15.

73. *Id.* at P 16.

74. *Id.* at P 23.

75. *Texas Gas Transmission, LLC*, 138 F.E.R.C. ¶ 61,175 (2012).

76. *Columbia Gulf Transmission Co.*, 138 F.E.R.C. ¶ 61,243 at P 1 (2012).

77. *Id.* at P 4.

78. *Id.* at PP 11, 16.

79. *Rockies Express Pipeline, LLC*, 134 F.E.R.C. ¶ 61,248 (2011).

80. *Rockies Express Pipeline, LLC*, 138 F.E.R.C. ¶ 61,241 at P 1 (2012).

FERC also addressed REX's compliance filing in response to the March 30, 2011 order.⁸¹ The FERC accepted and suspended REX's 2012 fuel filing, and set it for hearing with REX's 2011 fuel filing.⁸² The FERC rejected the request for rehearing, which sought reconsideration of the FERC's rejection of alternative fuel rates that "would have allowed REX recover certain quantities to reduce fuel recovery resulting from a negotiated fuel rate agreement."⁸³

On March 9, 2012, the FERC issued an order granting Trailblazer Pipeline Company, LLC's (Trailblazer) motion to terminate its expansion fuel adjustment percentage rate proceeding, affirming an Initial Decision holding that the issues were either resolved or moot, and accepting Trailblazer's December 29, 2011 revised tariff records.⁸⁴ This order relates to Trailblazer's June 3, 2011 filing updating its expansion fuel adjustment percentage rate to 8.69%.⁸⁵ Although the FERC set Trailblazer's June 3, 2011 filing for hearing, Trailblazer reached various settlements that rendered the issues resolved or moot.⁸⁶ The FERC accepted a 4.78% expansion fuel adjustment percentage rate.⁸⁷

On August 31, 2011, the FERC issued an order rejecting Trailblazer's July 25, 2011 proposal to modify its fuel tracker to implement a new expansion fuel adjustment percentage for "(a) interruptible service, (b) reverse firm backhaul transportation service, and (c) overruns under Rate Schedule FTS."⁸⁸ The FERC found that the proposed tariff records were contrary to the rate moratorium in Article IV of Trailblazer's 2010 settlement.⁸⁹ The FERC also found that Trailblazer's proposal "violates the prohibition against retroactive ratemaking" by permitting recovery of "accumulated under-recoveries . . . from shippers that were not subject to the prior [fuel charge] mechanism."⁹⁰

On August 10, 2011, the FERC dismissed a complaint by BG Energy Merchants, LLC and EXCO Operating Company, LP, which alleged that Crosstex LIG, LLC (Crosstex) "impermissibly assessed a fuel charge in excess of the contractual level."⁹¹ Crosstex provides intrastate service, as well as interstate transportation service pursuant to section 311 of the Natural Gas Policy Act.⁹² Although the FERC found that the complaint involved an issue of concurrent jurisdiction, it dismissed the complaint, finding that the "question of contract interpretation . . . should be resolved in the already pending State Court Proceeding in Texas."⁹³

81. *Id.* at PP 22-38.

82. *Id.* at PP 53, 55.

83. *Id.* at PP 9, 22.

84. *Trailblazer Pipeline Co.*, 138 F.E.R.C. ¶ 61,163 at P 13 (2012).

85. *Id.* at P 2.

86. *Id.* at PP 2, 13.

87. *Id.* at P 14.

88. *Trailblazer Pipeline Co.*, 136 F.E.R.C. ¶ 61,146 at P 2 (2011).

89. *Id.* at PP 23-24.

90. *Id.* at P 25.

91. *BG Energy Merchants, LLC and EXCO Operating Co. v. Crosstex LIG, LLC*, 136 F.E.R.C. ¶ 61,098 (2011).

92. *Id.* at P 2 (referencing 15 U.S.C. § 3371(a)(2)(A) (2006)).

93. *Id.* at P 35; *see also id.* at P 37 (holding that the FERC lacks the special expertise necessary to assume jurisdiction over the contract dispute).

I. Gas Quality and Interchangeability

In *PostRock KPC Pipeline, LLC* (KPC), the FERC accepted a proposed tariff revision allowing KPC to consider “whether and to what extent Shipper pairs nominations or the Shipper otherwise agrees to a blending or pairing arrangement” in deciding whether to accept nominations for gas that does not meet the gas quality specifications set forth in KPC’s tariff.⁹⁴ Following a technical conference, and the effective withdrawal of the only protest to KPC’s proposal, the FERC approved the filing, holding that “the [FERC] has encouraged pipelines to implement such pairing agreements.”⁹⁵

J. Leases

In *Midcontinent Express Pipeline, LLC* (Midcontinent), the FERC affirmed its approval of a lease that could reduce the amount of interruptible capacity available to the leasing pipeline’s shippers.⁹⁶ The FERC denied a shipper’s request for rehearing regarding the potential adverse impacts of the lease to interruptible shippers, holding that

as a general rule, the potential for a lease to diminish the amount of interruptible service that the lessor pipeline is able to provide should not be a disqualifying adverse effect under the *Islander East* test when that effect will be clearly outweighed by the benefits of the lease. . . . [A]ny other result would empower interruptible shippers on any pipeline’s system to prevent that pipeline from ever leasing any of its capacity to another pipeline.⁹⁷

K. Liability

The FERC rejected Paiute Pipeline Company’s (Paiute) proposed tariff revision that would have required shippers to “indemnify [the pipeline] against any claims related to Paiute’s passive or actively negligent failure to odorize gas.”⁹⁸ The FERC held that, because the proposed language “may shield Paiute from all liability, even liability resulting from its own gross negligence or willful misconduct,” the proposal was contrary to the FERC’s general principles that: “(1) there should be no liability without fault; and (2) neither a pipeline nor a shipper should be able to avoid all liability caused by its own gross negligence or intentional actions.”⁹⁹

In a proceeding to consider adjustments to CenterPoint Energy Gas Transmission Company’s (CenterPoint) fuel use and lost and unaccounted for gas percentages, the FERC entertained a protest regarding CenterPoint’s existing liability and damages tariff provisions.¹⁰⁰ The FERC held that the existing tariff provision “limiting [CenterPoint’s] liability to ‘sole or gross negligence, bad

94. *PostRock KPC Pipeline, LLC*, 138 F.E.R.C. ¶ 61,146 at P 6 (2012), *order following tech. conf.*, 139 F.E.R.C. ¶ 61,158.

95. *PostRock KPC Pipeline, LLC*, 139 F.E.R.C. ¶ 61,158 at P 6 (citing *Policy Statement on Provisions Governing Natural Gas Quality and Interchangeability in Interstate Natural Gas Pipeline Co. Tariffs*, 115 F.E.R.C. ¶ 61,325 at P 41 (2006)).

96. *Midcontinent Express Pipeline, LLC*, 136 F.E.R.C. ¶ 61,222 (2011).

97. *Id.* at P 25 (internal citations omitted).

98. *Paiute Pipeline Co.*, 139 F.E.R.C. ¶ 61,089 at PP 38, 43 (2012).

99. *Id.* at 43.

100. *CenterPoint Energy Gas Transmission Co.*, 139 F.E.R.C. ¶ 61,064 (2012).

faith or willful misconduct' . . . is inconsistent with [FERC] policy, and we therefore find it to be unjust and unreasonable."¹⁰¹ CenterPoint was directed to "revise its tariff or show cause why it should not be required to do so."¹⁰²

The FERC approved language in Tallulah Gas Storage, LLC's (Tallulah) tariff that "establishes a gross negligence standard solely in the context of liability for any punitive, special, or exemplary damages or consequential, indirect, or incidental damages or lost profits."¹⁰³ Although the FERC initially directed Tallulah to revise this language,¹⁰⁴ the FERC accepted Tallulah's clarification, and held that the proposed language was consistent with FERC policy because it "requires that parties be liable for direct damages arising out of their negligence, but limits the liability of Tallulah and its customers for indirect damages only to instances of gross negligence, willful misconduct, or bad faith actions."¹⁰⁵

L. Liquids

The FERC accepted National Fuel Gas Supply Corporation's (National Fuel) new plant thermal reduction (PTR) rate schedule establishing new PTR service.¹⁰⁶ The "PTR service . . . [applies] to the transportation of liquefiable hydrocarbons" received by National Fuel upstream of the processing plants which remove the liquefiabls from the gas stream.¹⁰⁷ The FERC accepted the PTR rate schedule on grounds that it "is similar to liquefiabls rate schedules offered by other natural gas pipelines."¹⁰⁸ However, the FERC denied National Fuel's requested waiver of section 154.402 regarding the applicability of the Annual Charge Adjustment (ACA) because other jurisdictional pipelines "appear to assess the ACA charge to their transportation of liquefiabls,"¹⁰⁹ and because section 154.402 requires companies to "reflect the ACA unit charge in each of its rate schedules applicable to sale or transportation."¹¹⁰

M. Market-Based Rates

In *UGI Storage Co.*, the FERC approved UGI Storage Company's (UGI Storage) application to provide interruptible wheeling services at market-based rates.¹¹¹ The FERC applied a three-part test to determine whether UGI Storage has the ability to exercise market power in providing wheeling services at market-based rates.¹¹² First, the FERC addressed the relevant product and

101. *Id.* at P 19.

102. *Id.* at P 21.

103. *Tallulah Gas Storage, LLC*, 137 F.E.R.C. ¶ 61,110 at P 9 (2011).

104. *Tallulah Gas Storage, LLC*, 134 F.E.R.C. ¶ 61,221 at P 62 (2011).

105. *Tallulah Gas Storage, LLC*, 137 F.E.R.C. ¶ 61,110 at P 13.

106. *National Fuel Gas Supply Corp.*, 137 F.E.R.C. ¶ 61,086 (2011).

107. *Id.* at P 2.

108. *Id.* at P 15.

109. *Id.* at P 15 (referencing *Southern Natural Gas Co.*, 65 F.E.R.C. ¶ 61,346 (1993); *Tennessee Gas Pipeline Co.*, 56 F.E.R.C. ¶ 61,463 (1991); *Tennessee Gas Pipeline Co.*, 59 F.E.R.C. ¶ 61,045 (1992); *Tennessee Gas Pipeline Co.*, 64 F.E.R.C. ¶ 61,020 (1993)).

110. *Id.* (quoting 18 C.F.R. § 154.402(a) (2011)).

111. *UGI Storage Co.*, 138 F.E.R.C. ¶ 61,051 at PP 1, 24(A) (2012).

112. *Id.* at P 11.

geographic market.¹¹³ Because “[i]nterruptible wheeling service is a transportation service that is not considered a substitute for gas storage service,” the FERC used a separate market power analysis, the “‘bingo card’ analysis[,] to [determine] whether prospective customers . . . seeking market-based rate authority for interruptible wheeling service could obtain the same services from alternative providers.”¹¹⁴ It concluded that “[t]he bingo card analysis [submitted by UGI Storage] demonstrates that shippers will not be dependent on UGI Storage to wheel natural gas in the New York and Pennsylvania area, since the area already contains a number of other pipeline interconnections and alternative paths available to shippers.”¹¹⁵ The FERC accepted the updated geographic market of New York and Pennsylvania that it previously approved in granting UGI Storage market-based rate authority for firm and interruptible storage services.¹¹⁶

Second, the FERC found that UGI Storage’s market share is similar to market shares previously approved by the FERC and that its market concentration is below the 1800 Herfindahl-Hirschman Index threshold level set forth in the *Alternative Rate Policy Statement*.¹¹⁷ Lastly, in addressing other relevant factors which mitigate UGI Storage’s potential exercise of market power, the FERC found that the lack of barriers to entry for interruptible wheeling service in the New York and Pennsylvania market indicates that UGI Storage “will not have the ability to unilaterally raise prices above competitive levels.”¹¹⁸

N. New Services

The FERC approved Gulf Crossing Pipeline Company’s (Gulf Crossing) proposed Enhanced Firm Transportation Service (EFT).¹¹⁹ Gulf Crossing’s “traditional Firm Transmission Service (FTS) is designed for a 1/24 hourly rate of flow,” while EFT is designed to accommodate gas flows at a 1/16 hourly rate of customers’ MDQs.¹²⁰ Gulf Crossing explained that, in response to its customers’ interests in more flexible hourly deliveries, it designed the EFT to provide firm transportation service at hourly rates.¹²¹ Gulf Crossing also claimed that a 1/16 hourly rate of flow “requires [1.5] times the amount of pipeline capacity” compared to a 1/24 hourly flow rate, and therefore proposed a reservation charge “of [1.5] times the existing FTS reservation charge.”¹²²

113. *Id.* at PP 12-15.

114. *Id.* at P 12.

115. *Id.* at P 13.

116. *Id.* at P 14.

117. *Id.* at PP 14-16 (The referenced “Alternative Rate Policy Statement” is cited as *Alternatives to Traditional Cost-of-Service Ratemaking for Natural Gas Pipelines and Regulation of Negotiated Transportation Services of Natural Gas Pipelines*, 74 F.E.R.C. ¶ 61,076, *reh’g and clarification denied*, 75 F.E.R.C. ¶ 61,024 (1996), *petitions for review denied sub nom.*, Burlington Resources Oil & Gas Co. v. FERC, 172 F.3d 918 (1996). *Id.* at n.13.) (emphasis added).

118. *Id.* at 17.

119. *Gulf Crossing Pipeline Co.*, 139 F.E.R.C. ¶ 61,082 at P 1 (2012).

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

121. *Id.* at P 2.

122. *Id.* at P 6.

The FERC accepted the proposed EFT, stating that it has previously approved “hourly firm transportation service[s]” which afforded “increased flexibility to . . . customers provided such service does not degrade the services provided to the pipeline’s existing shippers,” and also found no degradation of service under Gulf Crossing’s proposal.¹²³ The FERC also rejected a protest of Gulf Crossing’s proposal to offer EFT at the same fuel lost and unaccounted for (FL&U) rate of 1% currently applicable to FTS customers.¹²⁴ Advocating a 1.5% FL&U rate for EFT, the protester argued that “the proposed FL&U rate appeared unduly discriminatory and preferential” because the “EFT will require higher operating pressures which will [cause] more fuel” consumption than would otherwise occur under FTS.¹²⁵ The FERC dismissed this concern on grounds that, if EFT “causes Gulf Crossing to use more fuel than it recovered from its existing FL&U rate, Gulf Crossing will bear the risk of any under recovery” because Gulf Crossing has a fixed fuel rate in its approved tariff.¹²⁶

The FERC accepted Texas Gas’ proposed Enhanced Nominations Service (ENS).¹²⁷ “The North American Energy Standards Board (NAESB) [standards] currently provides shippers with four nomination cycles” of gas per day.¹²⁸ Texas Gas’ proposed ENS service provides shippers with “an additional eleven nomination cycles” per day which occur every two hours throughout the day.¹²⁹ “For each cycle, the confirmation deadline [occurs] one hour after the nomination deadline and the effective flow time [occurs] two hours after the nomination deadline.”¹³⁰ All “shippers holding firm and no-notice transportation service agreements at eligible receipt points” can receive the ENS service.¹³¹ Although ENS customers cannot “bump another firm shipper’s scheduled and flowing gas quantities,” ENS customers can “bump an interruptible shipper’s scheduled and flowing gas quantities.”¹³²

The FERC stated that Texas Gas’ proposed ENS service is “generally reasonable as [applied] to interruptible service.”¹³³ However, the FERC found that the proposed ENS service “is unclear as it relates to the advance notice provided to interruptible shippers whose quantities have been reduced, so that the interruptible shippers have the opportunity to make adjustments to their gas flow in response to the notice.”¹³⁴ Regarding the “proposed usage charge for ENS service,” the FERC further found that “[i]t is unclear based upon the tariff

123. *Id.* at P 19.

124. *Id.* at P 20.

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

126. *Id.* at P 20.

127. *Texas Gas Transmission, LLC*, 138 F.E.R.C. ¶ 61,176 at PP 1, 18 (2012) (acceptance of revised tariff schedule); *Texas Gas Transmission, LLC*, 137 F.E.R.C. ¶ 61,093 at PP 1, 24-25 (2011) (conditional acceptance of proposed tariff schedule).

128. 138 F.E.R.C. ¶ 61,176 at P 2; *see also* 137 F.E.R.C. ¶ 61,093 at P 2.

129. 138 F.E.R.C. ¶ 61,176 at P 2; *see also* 137 F.E.R.C. ¶ 61,093 at P 5.

130. 138 F.E.R.C. ¶ 61,176 at P 2; *see also* 137 F.E.R.C. ¶ 61,093 at P 6.

131. 138 F.E.R.C. ¶ 61,176 at P 2; *see also* 137 F.E.R.C. ¶ 61,093 at P 5.

132. 138 F.E.R.C. ¶ 61,176 at P 3; *see also* 137 F.E.R.C. ¶ 61,093 at P 8.

133. 138 F.E.R.C. ¶ 61,176 at P 4 (quoting 137 F.E.R.C. ¶ 61,093 at P 24).

134. 137 F.E.R.C. ¶ 61,093 at P 25.

when Texas Gas will assess its usage charge.”¹³⁵ The FERC therefore conditionally accepted Texas Gas’ proposed ENS service subject to its filing revised tariff records which provide interruptible shippers with “reasonable advance notice of bumping” prior to the gas flow, and indicate “when Texas Gas [will] assess the ENS usage charge.”¹³⁶ The FERC subsequently accepted Texas Gas’ compliance filing providing interruptible shippers with a one hour notice of bumping prior to the confirmation deadline.¹³⁷

In a separate order, the FERC accepted Texas Gas’ proposal to change its experimental Winter No-Notice (WNS) service from a temporary service to a permanent service.¹³⁸ “The experimental WNS service permits contract demand that varies on a monthly basis,” and provides shippers that take WNS service “with two additional nomination cycles.”¹³⁹ “[T]he permanent WNS service [proposed by Texas Gas is] identical to the existing experimental WNS service except for the elimination of the . . . two additional intra-day nomination cycles” from the permanent WNS service.¹⁴⁰ As Texas Gas explained, the FERC’s acceptance of the ENS service with eleven additional intra-day nomination cycles, discussed above, obviates the need for the two additional intra-day nomination cycles included in the temporary WNS service.¹⁴¹ One shipper urged the FERC to reject Texas Gas’ permanent WNS service, arguing that the pipeline cannot “grant[] variable contract demand rights to WNS service shippers” without also granting such rights to all firm shippers.¹⁴² However, the FERC accepted the permanent WNS service and stated that “[a] pipeline may offer varying monthly contract demand for certain types of firm service without offering varying monthly contract demand for all firm services.”¹⁴³ The FERC clarified that it does not require pipelines to offer “varying contract demand to all shippers[,] or all firm shippers,” “if the pipeline offers . . . varying contract demand for one particular firm service; rather, the [FERC] only requires that the varying contract demand be available to those shippers using the same firm service.”¹⁴⁴

Alliance Pipeline L.P. (Alliance) proposed the expansion of an existing service and two new ancillary services (collectively, the ACE Hub Services).¹⁴⁵ Alliance stated that it only provides firm transportation and interruptible transportation services,¹⁴⁶ and that its proposed ACE Hub Services will “facilitate new delivery and service opportunities in the Chicago market area”

135. *Id.* at P 47.

136. 138 F.E.R.C. ¶ 61,176 at P 4; *see also* 137 F.E.R.C. ¶ 61,093 at PP 25, 47.

137. 138 F.E.R.C. ¶ 61,176 at P 18.

138. *Texas Gas Transmission, LLC*, 138 F.E.R.C. ¶ 61,228 at PP 1, 11-12 (2012). The FERC originally accepted Texas Gas’ experimental WNS service in March 2010 for a two-year period. *Texas Gas Transmission, LLC*, 130 F.E.R.C. ¶ 61,158 at PP 1, 22 (2010); 138 F.E.R.C. ¶ 61,228 at P 2.

139. 138 F.E.R.C. ¶ 61,228 at P 2.

140. *Id.* at P 3.

141. *Id.*

142. *Id.* at P 6.

143. *Id.* at P 11.

144. *Id.* at P 12.

145. *Alliance Pipeline L.P.*, 136 F.E.R.C. ¶ 61,066 at P 1 (2011).

146. *Id.* at P 4.

and “allow market participants to gain greater commercial liquidity in their transactions and potentially to obtain greater delivery flexibility.”¹⁴⁷ First, Alliance proposed a no-charge Title Transfer service to “allow firm shippers to transfer title of gas to others for: (1) aggregation and disaggregation of gas; (2) delivery; and/or (3) nomination under a PAL transaction.”¹⁴⁸ Second, Alliance proposed three types of park-and-loan (PAL) services to allow shippers to park or obtain gas using available line pack capacity: Term PAL, Nom PAL, and Auto PAL.¹⁴⁹ “Term PAL [is] subject to the operational availability of line pack capacity”; “Nom PAL allows [shippers] to request service in each nominating cycle for one Gas Day”; and Auto PAL allows “shippers to contract for automatic nominations of a park or loan transaction[] on the shipper’s behalf to manage imbalances.”¹⁵⁰ Third, Alliance proposed “interruptible wheeling service [to allow] transportation through displacement” within the Alliance Chicago Exchange Hub (ACE Hub).¹⁵¹ Although the FERC rejected certain waiver requests and the proposed tariff records submitted by Alliance “for failure to comply with the notice provisions of section 154.207 of [FERC] regulations,”¹⁵² the FERC found that Alliance sufficiently supported its proposed ACE Hub Services and authorized it to file revised tariff records in compliance with section 154.207.¹⁵³ The FERC stated that it has previously approved new services “as part of an array of ancillary service offerings associated with a market hub.”¹⁵⁴ The FERC further stated that Alliance’s ACE Hub Services “will benefit market participants in the Chicago area by providing new delivery and service opportunities more tailored to their specific needs” and will “allow market participants the potential to gain greater liquidity in their various transactions and enhance their delivery flexibility, thereby, furthering the [FERC]’s goal of improving shipper service options.”¹⁵⁵

O. Non-Conforming Provisions

The FERC approved a number of non-conforming precedent agreement terms in certificating a pipeline expansion in *Texas Eastern Transmission, LP and Algonquin Gas Transmission, LLC*.¹⁵⁶ The FERC accepted non-conforming terms addressing “receipt point rights, hourly delivery flexibility, a one-time renewal right, a most favored nations provision with respect to the negotiated rate, revenue sharing, a contractual right of first refusal, and credit support requirements.”¹⁵⁷ In approving the non-conforming provisions, the FERC noted its previous finding “that non-conforming provisions may be necessary to reflect

147. *Id.* at P 5.

148. *Id.* at P 7.

149. *Id.* at P 9.

150. *Id.*

151. *Id.* at P 12.

152. *Id.* at P 35; *see also* 18 C.F.R. § 154.207 (2011).

153. 136 F.E.R.C. ¶ 61,066 at P 35.

154. *Id.* at P 36.

155. *Id.*

156. *Texas Eastern Transmission, LP and Algonquin Gas Transmission, LLC*, 139 F.E.R.C. ¶ 61,138 at PP 1, 55-57 (2012). The certificate aspects of this case are discussed further in section III.A, *infra*.

157. *Id.* at PP 55-57.

the unique circumstances involved with constructing new infrastructure and to provide the needed security to ensure the viability of a project.”¹⁵⁸

In *ETC Tiger Pipeline, LLC*, the FERC addressed numerous non-conforming provisions included in seven negotiated rate transportation service agreements for service on a new pipeline project.¹⁵⁹ The FERC accepted most of the proposed non-conforming provisions, including provisions addressing: (1) the primary contract term to account for the fact that the pipeline had not yet been constructed;¹⁶⁰ (2) interim service prior to the completion of certain pipeline facilities;¹⁶¹ (3) the right to assign the service agreements;¹⁶² (4) the ability to change primary receipt points to address a particular operational issue on the pipeline system;¹⁶³ (5) supply leg receipt pressures;¹⁶⁴ (6) caps on FL&U reimbursements;¹⁶⁵ (7) phased increases in contract volumes;¹⁶⁶ and a number of miscellaneous deviations intended for clarification purposes.¹⁶⁷ The FERC rejected, however, a proposed non-conforming provision that would have allowed a releasing shipper engaging in a permanent release of capacity in excess of the contract rate to retain a portion of the excess payment.¹⁶⁸ Such a provision, the FERC reasoned, was inconsistent with its policy against providing credits to a releasing shipper after a permanent release.¹⁶⁹

In *Portland Natural Gas Transmission System*, the FERC rejected a filing by Portland Natural Gas Transmission System (PNGTS) intended to comply with prior FERC decisions concerning a proposed non-conforming firm transportation service agreement.¹⁷⁰ In an October 2010 order, the FERC had rejected a proposed non-conforming provision in a PNGTS service agreement that would have allowed the shipper to reduce its contract demand prior to the expiration of the agreement under certain circumstances.¹⁷¹ PNGTS twice tried unsuccessfully to comply with the FERC’s directive to remove the non-conforming provision from the service agreement “or offer it on a non-discriminatory basis to all shippers.”¹⁷² In one instance, PNGTS filed a settlement under which the non-conforming provision would be eliminated in

158. *Id.* at P 56 (citing *Midcontinent Express Pipeline LLC*, 124 F.E.R.C. ¶ 61,089 (2008) and *Rockies Express Pipeline LLC*, 116 F.E.R.C. ¶ 61,272 at P 78 (2006)).

159. *ETC Tiger Pipeline, LLC*, 138 F.E.R.C. ¶ 61,035 (2012). The FERC also addressed a contractual dispute between the pipeline company and a customer relating to whether a service agreement became effective prior to the completion of non-jurisdictional upstream facilities. *Id.* at PP 33-41.

160. *Id.* at P 46.

161. *Id.* at P 47.

162. *Id.* at PP 48-51.

163. *Id.* at P 52.

164. *Id.* at PP 53-55.

165. *Id.* at PP 57-58.

166. *Id.* at P 59.

167. *Id.* at PP 60-62.

168. *Id.* at P 50.

169. *Id.* (citing *Rockies Express Pipeline*, 121 F.E.R.C. ¶ 61,130 at P 30 (2007)).

170. *Portland Nat. Gas Transmission Sys.*, 138 F.E.R.C. ¶ 61,010 at P 1 (2012).

171. *Id.* at P 2 (citing October 2010 Order, *Portland Nat. Gas Transmission Sys.*, 133 F.E.R.C. ¶ 61,050 (2010)).

172. *Id.* at P 7 (quoting October 2010 Order, 133 F.E.R.C. ¶ 61, 050 at P17).

exchange for a \$40,000 payment to the shipper.¹⁷³ By its terms, however, the proposed settlement became null and void if the FERC deemed the \$40,000 payment to be a discount, as such a finding would have triggered the most-favored-nation clauses in PNGTS's other service agreements.¹⁷⁴ The FERC found the \$40,000 payment would indeed be a discount, rendering the settlement null and void and leaving PNGTS in non-compliance with the October 2010 order.¹⁷⁵

Trying again, PNGTS proposed to amend the GT&C of its tariff to state that the offending provision of the relevant service agreement was null and void.¹⁷⁶ The FERC rejected this approach to addressing the non-conforming provision, finding PNGTS's proposal was: (1) inconsistent with the FERC's regulations governing the GT&C provisions of pipeline tariffs;¹⁷⁷ and (2) unnecessary because the FERC's October 2010 order rejecting the non-conforming provision had already rendered it null and void.¹⁷⁸ The FERC explained that "the correct course of action for Portland [would be] to file a revised service agreement, removing the unlawful contract demand reduction provision."¹⁷⁹

The FERC considered a filing by Florida Gas Transmission Company, LLC (FGT) that: (1) updated FGT's list of non-conforming service agreements to include several agreements containing potential material deviations from FGT's *pro forma* service agreement; and (2) identified deviations from the *pro forma* agreement in numerous other service agreements that FGT maintained were not material.¹⁸⁰ The FERC agreed with FGT's position as to the non-materiality of the non-conforming provisions identified by FGT.¹⁸¹ With respect to the small number of agreements that FGT acknowledged might contain non-conforming provisions, the FERC considered each individual agreement, accepting: (1) a provision that limited total quantities delivered at a certain point under all the shipper's service agreements based on operational limitations;¹⁸² and (2) a provision that provided for the consolidation of service agreements under multiple rate schedules for purposes of making nominations, scheduling and billing.¹⁸³ The FERC rejected non-conforming provisions that: (1) would have negated a shipper's right to terminate its agreement in the event of electric deregulation as provided by the *pro forma* agreement; and (2) would have required FGT's consent for the shipper to reduce its MDQ and/or terminate the agreement based on FGT's inability to deliver designated volumes.¹⁸⁴

173. *Portland Nat. Gas Transmission Sys.*, 137 F.E.R.C. ¶ 61,004 (2011).

174. *Id.* at PP 4-5, 9.

175. *Id.* at PP 9-11.

176. *Portland Nat. Gas Transmission Sys.*, 138 F.E.R.C. ¶ 61,010 at P 5.

177. *Id.* at P 8 (citing 18 C.F.R. § 154.109(a)).

178. *Id.* at P 9.

179. *Id.* at P 10.

180. *Florida Gas Transmission Co.*, 138 F.E.R.C. ¶ 61,008 at PP 3-6 (2012).

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

182. *Id.* at P 28.

183. *Id.* at P 34.

184. *Id.* at PP 25-26.

In *Bison Pipeline LLC*, the FERC denied rehearing of an order in which it had rejected a non-conforming provision included in several transportation service agreements filed by Bison Pipeline LLC (Bison).¹⁸⁵ The non-conforming provision allowed Bison to terminate the service agreement upon the occurrence of certain specified events pertaining to the shipper's creditworthiness, with such termination effective upon the shipper's receipt of Bison's termination notice.¹⁸⁶ Affirming its earlier decision, the FERC found that the termination provision was inconsistent with its regulations requiring at least thirty days advance notice to the FERC prior to the termination of a service agreement.¹⁸⁷ The FERC acknowledged that its policy is to allow new pipelines to include stricter creditworthiness requirements in the initial shippers' service agreements, but found that such policy does not justify dispensing with the requirement for advance notice of cancellation of service.¹⁸⁸

In *Algonquin Gas Transmission, LLC*, the FERC considered numerous potentially non-conforming service agreements filed by Algonquin Gas Transmission, LLC (Algonquin).¹⁸⁹ Algonquin identified twenty-two agreements that potentially contained material deviations from the *pro forma* service agreement and another seventeen agreements that Algonquin contended contained only immaterial deviations.¹⁹⁰ The FERC accepted all of the twenty-two agreements containing material deviations.¹⁹¹ The majority of these agreements, the FERC found, contained non-conforming provisions related to compliance with the FERC's previous natural gas industry restructuring or expansion projects, had been extended prior to the FERC's 2001 clarification of its policy governing non-conforming agreements, and could therefore be grandfathered.¹⁹² The remainder of the twenty-two agreements contained permissible deviations.¹⁹³

In reviewing the seventeen agreements that, according to Algonquin, contained only non-material deviations, the FERC identified two deviations from the *pro forma* service agreement that it deemed material.¹⁹⁴ The FERC rejected one of these non-conforming provisions – a provision that purported to specify a precise hourly flow limitation in a manner inconsistent with Algonquin's tariff.¹⁹⁵ The other material deviation related to a provision specifying that certain receipt and delivery points were only available on a secondary basis, whereas the service agreement contemplated the specification of primary

185. *Bison Pipeline LLC*, 137 F.E.R.C. ¶ 61,226 at P 1 (2011).

186. *Id.* at P 2.

187. *Id.* at P 9 (citing 18 C.F.R. § 154.602).

188. *Id.* at P 13.

189. *Algonquin Gas Transmission, LLC*, 137 F.E.R.C. ¶ 61,178 (2011).

190. *Id.* at P 12.

191. *Id.* at PP 17-22.

192. *Id.* at PP 16-17 (citing *Columbia Gas Transmission Corp.*, 97 F.E.R.C. ¶ 61,221 (2001); *Texas Eastern Transmission, LP*, 119 F.E.R.C. ¶ 61,337 (2007); *Transcontinental Gas Pipe Line Co.*, 136 F.E.R.C. ¶ 61,104 (2011)).

193. *Id.* at P 19.

194. *Id.* at P 23.

195. *Id.* at P 27.

points.¹⁹⁶ The FERC found that the deviation reflected the terms of a settlement and was not unduly discriminatory.¹⁹⁷

In issuing a certificate for a new project proposed by Central New York Oil and Gas Company, LLC (CNYOG), the FERC addressed non-conforming provisions included in the precedent agreements for a project.¹⁹⁸ The FERC approved certain non-conforming terms that CNYOG offered to its initial shippers relating to most-favored-nation treatment for subsequent expansions of capacity, the ability to negotiate minimum and maximum pressure assurances at key delivery points, liquidated damages in case certain in-service deadlines were not met, creditworthiness for initial service, and equal treatment with any anchor shipper for expansion capacity added within the first five years.¹⁹⁹ The FERC found that such non-conforming conditions were acceptable in the unique circumstances of a new project and did not result in undue discrimination.²⁰⁰

In *Tennessee Gas Pipeline Co.*, the FERC considered two specific non-conforming provisions included in precedent agreements between Tennessee and two sponsoring shippers contracting for new incremental pipeline capacity.²⁰¹ The FERC accepted a non-conforming provision that would permit each shipper to extend the twenty-year primary term of its respective service agreement for successive five-year terms at the negotiated rate upon twenty four months' notice.²⁰² The FERC rejected, however, a minimum delivery pressure provision in one of the precedent agreements.²⁰³ The FERC observed that “[a]lthough . . . we have clarified that pipelines may provide incentives to induce sponsoring shippers to commit to a project, we did not extend this policy to include non-rate considerations.”²⁰⁴

In *Transcontinental Gas Pipe Line Co.*, a pipeline filed a number of service agreements that had been executed years before and that contained potentially material deviations from the relevant *pro forma* service agreements.²⁰⁵ The FERC noted that some of the agreements filed by Transco should not be treated as non-conforming because they “conform[ed] to the *pro forma* service agreement[s] in effect at the time the contract[s] became effective and contain[ed] *Memphis* clause[s],”²⁰⁶ citing its decision in *Texas Gas Transmission, LLC*.²⁰⁷ The FERC permitted Transco to “grandfather” the non-

196. *Id.* at P 31.

197. *Id.*

198. *Central New York Oil and Gas Co.*, 137 F.E.R.C. ¶ 61,121 at PP 35-45 (2011). Other aspects of this case are discussed further in section III.A, *infra*.

199. *Central New York Oil and Gas Co.*, 137 F.E.R.C. ¶ 61,121 at PP 35-45 (2011).

200. *Id.* at P 43.

201. *Tennessee Gas Pipeline Co.*, 136 F.E.R.C. ¶ 61,125 at PP 22-30 (2011).

202. *Id.* at PP 23, 28.

203. *Id.* at P 29.

204. *Id.* (citing *Gulf Crossing Pipeline Co.*, 123 F.E.R.C. ¶ 61,100 (2008)).

205. *Transcontinental Gas Pipe Line Co.*, 136 F.E.R.C. ¶ 61,104 (2011).

206. *Id.* at P 6 (citing *United Gas Pipe Line Co. v. Memphis Light, Gas and Water Div.*, 358 U.S. 103 (1958); Order No. 678-A, *Rate Regulation of Certain Natural Gas Storage Facilities, order on clarification and reh'g*, 117 F.E.R.C. ¶ 61,190 at P 7 (2006)).

207. *Id.* (citing *Texas Gas Transmission, LLC*, 130 F.E.R.C. ¶ 61,114 at P 16 (2010)).

conforming contractual right of first refusal provision in two agreements,²⁰⁸ but declined to grandfather a deviating contract rollover provision in another agreement.²⁰⁹ The FERC also declined to grandfather the contract-demand reduction and most-favored-nation provisions in a non-conforming bypass letter agreement between Transco and a local distribution company.²¹⁰ Finally, the FERC required Transco to further justify a non-conforming provision requiring the payment of liquidated damages for failure to make firm deliveries at minimum delivery pressures.²¹¹

At issue in *Gas Transmission Northwest Corp.* were 107 potentially non-conforming service agreements filed by Gas Transmission Northwest Corporation (GTN).²¹² The FERC summarily accepted all but three of the contracts, discussing three non-conforming provisions included in the agreements.²¹³ The FERC agreed to grandfather: (1) a provision giving the shipper the option to increase its contract quantity at its primary receipt and delivery points at a specified rate; and (2) a provision allowing a shipper to reduce its contract demand under the agreement in the event of a bypass.²¹⁴ The FERC required GTN to provide additional justification for another non-conforming minimum delivery pressure provision in a service agreement, remove the relevant provision, or amend its tariff to allow for the negotiation of minimum pressure obligations.²¹⁵

P. Notices

The FERC denied rehearing of an earlier order allowing Tennessee to modify the routine maintenance provisions of its tariff.²¹⁶ The FERC reaffirmed its approval of Tennessee's proposals to: (1) permit routine maintenance at any time except during "periods of peak demand";²¹⁷ and (2) reduce the maintenance outage notification requirement from 15 days advance notice to "as soon as reasonably practicable, but no later than five days prior to the scheduled activity."²¹⁸

Q. Open Seasons

In *Pine Prairie Energy Center, LLC*, the FERC affirmed, on rehearing, that the requirement to hold an open season to solicit turn-back capacity applies to all expansion projects regardless of whether the project will provide storage service at market-based rates.²¹⁹ The FERC explained the "basis of our turn-back

208. *Id.* at P 12.

209. *Id.* at P 16.

210. *Id.* at PP 20-21.

211. *Id.* at P 23.

212. *Gas Transmission Northwest Corp.*, 136 F.E.R.C. ¶ 61,105 (2011).

213. *Id.* at P 16.

214. *Id.* at PP 19, 21.

215. *Id.* at P 22.

216. *Tennessee Gas Pipeline Co.*, 136 F.E.R.C. ¶ 61,048 at P 1 (2011).

217. *Id.* at PP 2, 13-20.

218. *Id.*

219. *Pine Prairie Energy Center, LLC*, 137 F.E.R.C. ¶ 61,060 at P 1 (2011).

capacity open season requirement is to properly size expansion projects to avoid the harm inherent in *unnecessary* disruption to the environment and impacts to landowners, and the *unnecessary* exercise of eminent domain.²²⁰ Thus, the FERC's "open season policies are based on non-rate-related factors and apply . . . regardless of whether [the pipeline] charge[s] cost-based or market-based rates."²²¹ As such, the FERC affirmed that the tariff provision providing "Pine Prairie with the discretion on whether to hold an open season, is unjust and unreasonable."²²²

The FERC rejected Turtle Bayou Gas Storage Company, LLC's (Turtle Bayou) late-filed request for rehearing, but clarified that its prior denial of authorization to Turtle Bayou to construct a storage facility was not based solely on Turtle Bayou's failure to conduct an open season.²²³ Rather, it was "because Turtle Bayou failed to present evidence of sufficient public benefits to outweigh the identified adverse impacts on [landowners]" and it was in the context of evaluating the project's public benefits that the FERC noted that by not conducting an open season, Turtle Bayou did not present any evidence demonstrating a market demand for the project.²²⁴ The FERC also affirmed "that, in a case where the project sponsor will need to obtain virtually all of the property rights needed for the project from unwilling property owners, the applicant needs to make a showing of public benefits proportional to the potential exercise of eminent domain."²²⁵

R. Operational Sales and Purchases

The FERC denied requests for rehearing of its order determining that Transco's proposed incremental rate treatment of the base gas purchase costs associated with its Washington Storage Service was just and reasonable.²²⁶ On rehearing, two shippers claimed it was discriminatory and contrary to FERC policy to charge historic shippers and new shippers different rates for the same service.²²⁷ The FERC determined that the pipeline's proposal was reasonable based on the facts and cost causation principles, and affirmed that in this situation, new shippers are not similarly situated with historic shippers.²²⁸

S. Penalties

The FERC approved El Paso Natural Gas Company's (El Paso) request for waiver of critical operating condition and strained operating condition penalties and charges incurred by El Paso's customers during the first week of February 2011, a time in which the Southwestern United States experienced unexpectedly

220. *Id.* at P 28.

221. *Id.* at P 34.

222. *Id.*

223. *Turtle Bayou Gas Storage Co.*, 139 F.E.R.C. ¶ 61,033 at PP 12-15 (2012).

224. *Id.* at P 13.

225. *Id.* at P 15.

226. *Transcontinental Gas Pipe Line Co.*, 139 F.E.R.C. ¶ 61,002 at P 25 (2012), *appeal docketed*, No. 12-1242 (D.C. Cir. June 1, 2012).

227. *Id.* at PP 33-41.

228. *Id.* at P 69.

extreme cold, resulting in extreme demand spikes and unexpected third-party operational failures.²²⁹ The FERC granted the waiver request but found that “granting waiver of El Paso’s penalty provisions for shippers does not necessarily affect a shipper’s classification as an ‘offending’ shipper that has incurred the penalty.”²³⁰

The FERC accepted Gulf South’s proposal to switch from monthly to daily allocations and charge any customer that exceeds its MDQ the existing Overrun Rate.²³¹ However, the FERC rejected Gulf South’s proposal to use the average system rate for a service as the Overrun Rate in place of the existing rate that was designed based on a 100 percent load factor derivative of the maximum cost-based rate for that service.²³² The FERC found that charging a shipper the Overrun Rate for capacity it uses in excess of its contract demand “is not a penalty, but simply a charge for service received.”²³³

T. Rate Cases

El Paso Natural Gas, RP08-426: On May 4, 2012, the FERC issued Opinion No. 517, its order on the Initial Decision issued in El Paso’s NGA section 4 rate increase proceeding in FERC Docket No. RP08-426-000.²³⁴ The FERC affirmed the decisions of the Presiding Administrative Law Judge (ALJ) on all four issues that had been the subject of the evidentiary hearing, though it reversed the ALJ on one subsidiary issue related to one of the four issues.²³⁵ El Paso was ordered to file revised tariff sheets and make refunds consistent with the FERC’s rulings within thirty days.²³⁶

This proceeding began with El Paso’s filing of a general rate increase proceeding on June 30, 2008.²³⁷ On March 13, 2010, El Paso filed an uncontested settlement that resolved most of the issues in the case, but reserved four issues for hearing and a merits determination.²³⁸ First, the FERC affirmed the ALJ’s ruling that El Paso may not recover \$25.7 million in costs associated with its acquisition of a crude oil pipeline, a portion of which it converted to gas service.²³⁹ The disallowed costs were associated with a portion of the line not certificated and put into service, and therefore deemed not “used or useful.”²⁴⁰

Second, the FERC affirmed that El Paso’s proposed capital structure was not just and reasonable and, in particular, that El Paso’s balance in its corporate-wide Cash Management Program included a \$615 million loan to its parent corporation that should be removed from the pipeline’s equity component.²⁴¹

229. *El Paso Natural Gas Co.*, 136 F.E.R.C. ¶ 61,219 at PP 1-2 (2011).

230. *Id.* at PP 16-17.

231. *Gulf South Pipeline Co.*, 139 F.E.R.C. ¶ 61,086 at P 17 (2012).

232. *Id.* at P 32.

233. *Id.* at P 55.

234. Opinion No. 517, *El Paso Natural Gas Co.*, 139 F.E.R.C. ¶ 61,095 (2012).

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

236. *Id.* at ordering P (D).

237. *Id.* at P 1.

238. *Id.* at P 15.

239. *Id.* at P 44.

240. *Id.*

241. *Id.* at PP 55-56.

The FERC also affirmed the ALJ's exclusion of a \$145 million undistributed subsidiary earnings amount resting with El Paso's wholly-owned subsidiary Mojave Pipeline Company, LLC.²⁴² In both cases, the questioned amounts were not available for jurisdictional purposes.²⁴³

Third, the FERC rejected El Paso's proposal to use a multiplier of 2.5 for its maximum recourse IT rates, because said proposal did not meet either the Order No. 637 model for term-differentiated rates or its model for seasonal rate, nor did it satisfy "the fundamental principle of ratemaking" that pipeline rates must be designed "to recover the costs properly allocated to the service."²⁴⁴ Finally, the FERC resolved issues relating to certain rate caps for defined customer classes under Article 11.2 of El Paso's 1996 rate settlement.²⁴⁵

On September 30, 2011, the FERC accepted and suspended Sea Robin's rate filing proposing to increase its Hurricane Surcharge and seeking waiver of certain provisions regarding the calculation of the Hurricane Surcharge, effective October 1, 2011, subject to refund and the outcome of related, ongoing hearings.²⁴⁶ Sea Robin previously established the Hurricane Surcharge to record and recover hurricane-related costs in 2009 through a limited NGA section 4 tariff filing.²⁴⁷ The FERC determined in its September 30, 2011 suspension order that Sea Robin had not shown that the proposed surcharge increase was just and reasonable, and that the proposed tariff records overlapped with other ongoing issues that would address the calculation of Sea Robin's Hurricane Surcharge, as well as previously proposed increases to the surcharge.²⁴⁸

On December 15, 2011, the FERC issued Opinion No. 516, affirming and reversing in part an ALJ's Initial Decision.²⁴⁹ The FERC affirmed the ALJ's holdings that capital costs could be included in Sea Robin's Hurricane Surcharge, the actual costs included in the proposed surcharge were reasonable, and the volumes used to design the surcharge were reasonable.²⁵⁰ The FERC reversed "the ALJ's findings regarding the Hurricane Surcharge recovery period, the date carrying charges should begin to accrue, and [the] applicability of the Hurricane Surcharge to certain discount agreements."²⁵¹

On April 29, 2011, the FERC approved an uncontested settlement filed by HIOS regarding the applicability of a storm event tracker surcharge (Storm Event Surcharge), which HIOS previously initiated in an offer of settlement to its March 31, 2009 section 4 rate case.²⁵² At the time of the April 29, 2011 order, the FERC stated that it was not ruling on the applicability of the Storm

242. *Id.*

243. *Id.* The FERC also upheld the ALJ's determination to reject calls from the Trial Staff and other parties that additional ring-fencing measures were necessary, concluding that El Paso was generally in compliance with the FERC's Cash Management Program requirements. *Id.* at P 134.

244. *Id.* at PP 155, 177.

245. *Id.* at P 247.

246. *Sea Robin Pipeline Co.*, 136 F.E.R.C. ¶ 61,229 at P 1 (2011).

247. *Id.* at P 2.

248. *Id.* at P 21.

249. Opinion No. 516, *Sea Robin Pipeline Co.*, 137 F.E.R.C. ¶ 61,201 at P 1 (2011).

250. *Id.* at P 14.

251. *Id.* at P 2.

252. *High Island Offshore Sys., L.L.C.*, 138 F.E.R.C. ¶ 61,114 at P 1 (2012).

Event Surcharge to certain Rate Schedule FT-2 shippers (Reserved Issue), and that it would defer action on the Reserved Issue until later.²⁵³ In the February 20, 2012 order, the FERC ruled on a previously Reserved Issue, and determined that HIOS could establish a volumetric surcharge applicable to all Rate Schedule FT-2 shippers on HIOS' system, but that HIOS must remove tariff language indicating that the Storm Event Surcharge may not be discounted.²⁵⁴

Columbia Gulf, RP11-1435: On December 1, 2011, the FERC approved the uncontested Stipulation and Agreement of Settlement filed by Columbia Gulf regarding all issues related to its section 4 general rate case.²⁵⁵ Notably, "Columbia Gulf's existing Mainline and Onshore Zones will be combined into a single Market Zone with postage stamp rates."²⁵⁶ The FERC also accepted, effective May 1, 2011, the tariff record that Columbia Gulf filed to comply with the FERC's April 29, 2011 order on the technical conference regarding Columbia Gulf's rate case, which addressed Critical Period Notices and OFOs, hourly scheduling penalties, flow control equipment, Columbia Gulf's Unauthorized Gas Penalty, and Auctions of Available Firm Service.²⁵⁷

National Fuel, RP12-88: On October 31, 2011, National Fuel filed for a general rate increase under section 4 of the NGA.²⁵⁸ In its filing, National Fuel submitted two sets of proposed tariff records with an alternative rate design for consideration by the FERC: a Base Case and a Preferred Case reflecting the elimination of National Fuel's existing Niagara rate zones by rolling the costs of the Niagara facilities into the system-wide cost of service.²⁵⁹ On November 30, 2011, the FERC accepted and suspended the filing, subject to refund and the outcome of hearing procedures.²⁶⁰ In its suspension order, the FERC also accepted National Fuel's proposed tariff revisions regarding whether to permit a discount adjustment for the pipeline's negotiated rate transactions in a general section 4 rate case, effective December 1, 2011.²⁶¹ Finally, the FERC ordered National Fuel to make a compliance filing modifying its existing tariff concerning reservation charge credits during *force majeure* and non-*force majeure* events or explain why it should not be required to do so.²⁶²

On September 29, 2011, the FERC accepted and suspended, effective October 1, 2011, subject to refund and the outcome of Stingray Pipeline Company, L.L.C.'s (Stingray) pending general section 4 proceeding, Stingray's proposed tariff revision to increase its Event Surcharge to \$0.0644/Dth which allows it to recover actual costs for system repairs caused by hurricanes and other named storms.²⁶³ Previously, the FERC accepted and suspended a

253. *Id.* at P 6.

254. *Id.* at P 10.

255. *Columbia Gulf Transmission Co.*, 137 F.E.R.C. ¶ 61,177 at P 1 (2011).

256. *Id.* at P 11.

257. *Id.* at P 35.

258. *National Fuel Gas Supply Corp.*, 137 F.E.R.C. ¶ 61,171 at P 1 (2011).

259. *Id.*

260. *Id.* at 2.

261. *Id.* at PP 31-32.

262. *Id.* at PP 34-35.

263. *Stingray Pipeline Co.*, 136 F.E.R.C. ¶ 61,225 at PP 1, 4 (2011).

proposal from Stingray's March 31, 2011 general section 4 rate case to eliminate a \$0.02/Dth cap on its Event Surcharge.²⁶⁴

Kern River, RP04-274: On July 21, 2011, the FERC affirmed, in Opinion No. 486-E, the April 14, 2011 Initial Decision on all matters established by Opinion No. 486-C,²⁶⁵ regarding the step-down rates Kern River Gas Transmission Company's (Kern River) firm shippers will be entitled to when their current contracts expire, with one exception.²⁶⁶ The FERC upheld the April 14 initial decision that "(1) Period One shippers be offered the option of entering into 10 or 15-year contracts for service during Period Two" and "(2) its Period Two levelized rates should be designed to recover the entire 30 percent of its invested capital remaining at the end of Period One over the 10 or 15-year terms of those contracts."²⁶⁷ However, the FERC required that "Period Two shippers be offered service at stepped-down Period Three rates" at the end of those contracts in order to reflect "the removal from Kern River's rate base of all its original invested capital."²⁶⁸ The FERC also affirmed the ALJ's approval of Kern River's other proposed eligibility requirements for Period Two shippers, with the exception of its rejection of the requirement that all shippers contracting for Period Two service must do so under Rate Schedule KRF-1.²⁶⁹

On August 29, 2011, the FERC conditionally accepted Kern River's proposed eligibility requirements in compliance with Opinion No. 486-E, but stated that it would issue a subsequent order to address rates.²⁷⁰ On September 30, 2011, the FERC accepted Kern River's proposed tariff record related to Period Two rates, effective October 1, 2011.²⁷¹

U. Rate Investigations

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.

On August 4, 2011 and September 22, 2011, respectively, the FERC approved uncontested settlements filed by Ozark Gas Transmission, L.L.C.,²⁷² and Kinder Morgan Interstate Gas Transmission, LLC,²⁷³ thereby resolving the FERC-initiated investigations into their respective rates. In addition, the FERC approved a settlement filed by Tuscarora Gas Transmission Company to resolve the rate investigation initiated by the FERC in response to a complaint by the Public Utilities Commission of Nevada and Sierra Pacific Power Company d/b/a NV Energy.²⁷⁴

264. *Stingray Pipeline Co.*, 135 F.E.R.C. ¶ 61,099 at PP 1, 12 (2011).

265. Opinion No. 486-C, *Kern River Gas Transmission Co.*, 129 F.E.R.C. ¶ 61,240 at PP 1-2 (2009).

266. Opinion No. 486-E, *Kern River Gas Transmission Co.*, 136 F.E.R.C. ¶ 61,045 at P 1 (2011).

267. *Id.* at P 60.

268. *Id.*

269. *Id.* at P 1.

270. *Kern River Gas Transmission Co.*, 136 F.E.R.C. ¶ 61,141 at P 1 (2011).

271. *Kern River Gas Transmission Co.*, 136 F.E.R.C. ¶ 61,241 at P 1 (2011).

272. *Ozark Gas Transmission, L.L.C.*, 136 F.E.R.C. ¶ 61,079 at P 12 (2011).

273. *Kinder Morgan Interstate Gas Transmission LLC*, 136 F.E.R.C. ¶ 61,201 at P 18 (2011).

274. *Pub. Utils. Comm'n of Nevada v. Tuscarora Gas Transmission Co.*, 138 F.E.R.C. ¶ 61,166 at PP 1-3 (2012).

In *Bear Creek Storage Co.*, the FERC determined that Bear Creek Storage Company L.L.C. (Bear Creek) appeared to be “substantially over-recovering its cost of service” based on the cost and revenue information provided by the storage operator in its 2009 and 2010 FERC Form No. 2 submissions.²⁷⁵ The FERC initiated an investigation into the justness and reasonableness of Bear Creek’s rates.²⁷⁶ The FERC subsequently denied Bear Creek’s request for rehearing of the requirement that it submit a cost and revenue study in the form mandated by section 154.312 of the FERC’s regulations for major rate changes,²⁷⁷ rather than in the form required by section 154.313 of the FERC’s regulations for minor rate changes.²⁷⁸ The FERC also denied Bear Creek’s challenge to the FERC’s legal authority to order submission of a cost and revenue study.²⁷⁹

In *MIGC LLC*, (MIGC) the FERC determined that MIGC appeared to be “substantially over-recovering its cost of service” based on the cost and revenue information provided by MIGC in its 2009 and 2010 FERC Form No. 2 submissions.²⁸⁰ The FERC initiated an investigation into “the justness and reasonableness of MIGC’s rates.”²⁸¹ As with Bear Creek, the FERC denied MIGC’s argument on rehearing that because of its small size, it should not be required to provide a cost and revenue study in the form mandated by section 154.312 of the FERC’s regulations.²⁸² On May 16, 2012, the presiding ALJ issued an “Initial Decision Terminating [the] Proceeding.”²⁸³ The ALJ ruled in response to an unopposed motion filed by the FERC staff, which had reviewed MIGC’s cost and revenue study and determined “that MIGC is not over-recovering its cost of service or earning an unreasonable return on equity, and likely will not in the future.”²⁸⁴ The FERC issued a notice on June 25, 2012 stating that it would not take action on the Initial Decision, which thereby became a final FERC decision.²⁸⁵

In *ANR Storage Co.*, the FERC determined that ANR Storage Company (ANR Storage) appeared to be “substantially over-recovering its cost of service” based on the cost and revenue information provided by ANR Storage in its 2009 and 2010 FERC Form No. 2 submissions.²⁸⁶ The FERC initiated an investigation into the justness and reasonableness of ANR Storage’s rates.²⁸⁷

275. *Bear Creek Storage Co.*, 137 F.E.R.C. ¶ 61,134 at PP 1, 6-7 (2011), *reh’g denied*, 138 F.E.R.C. ¶ 61,019 (2012).

276. *Id.* at P 8.

277. *Bear Creek Storage Co.*, 138 F.E.R.C. ¶ 61,019 at P 6; *see also* 18 C.F.R. § 154.312 (2012).

278. 18 C.F.R. § 154.313 (2012).

279. *Bear Creek Storage Co.*, 138 F.E.R.C. ¶ 61,019 at P 27.

280. *MIGC LLC*, 137 F.E.R.C. ¶ 61,135 at PP 1, 6-7 (2011), *order on reh’g*, 138 F.E.R.C. ¶ 61,011 (2012).

281. *MIGC LLC*, 137 F.E.R.C. ¶ 61,135 at P 8.

282. *MIGC LLC*, 138 F.E.R.C. ¶ 61,011 at P 40.

283. *MIGC LLC*, 139 F.E.R.C. ¶ 63,012 (2012).

284. *Id.* at P 17.

285. *MIGC LLC*, 139 F.E.R.C. ¶ 63,251 (2012).

286. *ANR Storage Co.*, 137 F.E.R.C. ¶ 61,136 at PP 1, 6-7 (2011).

287. *Id.* at P 8.

V. Rate Schedules

The FERC approved a settlement establishing the terms under which Kern River would be permitted to eliminate several “Self-Contained Rate Schedules” that had been negotiated when Kern River’s original system was certificated in 1990.²⁸⁸ Under the settlement, the shippers under the Self-Contained Rate Schedules would be served under a single rate schedule, under service agreements containing material deviations intended to maintain the benefits of the parties’ original bargains.²⁸⁹ The FERC approved the settlement and the proposed material deviations, holding that the deviations “allow the continuation of contractual provisions agreed to between Kern River and its shippers during its optional expedited certificate proceeding.”²⁹⁰

W. Reservation Charge Credits for Curtailment

In *Natural Gas Supply Assoc.*, the FERC set out its policies regarding reservation charge crediting during pipeline outages.²⁹¹ In sum, the FERC held that for non-*force majeure* events, a pipeline must give firm shippers a full reservation charge credit for the amount of primary firm service the shipper nominated for scheduling but the pipeline failed to deliver.²⁹² For *force majeure* events, a pipeline may share the risk of such events with its shippers as long as the sharing mechanism is equitable.²⁹³ The FERC has approved two methods of equitable sharing for *force majeure events*: (1) Safe Harbor Method – a full reservation charge credit beginning after a “short grace period” (i.e., ten days or less); or (2) No-Profit Method – a partial reservation charge credit starting on the first day of the outage “covering the portion of the pipeline’s reservation charge that represents the pipeline’s return on equity and associated income taxes.”²⁹⁴

The FERC has clarified these policies in recent cases. In *Northern Natural Gas Co.*, the FERC held that where a non-straight fixed variable rate design allocates only a minimal amount of fixed costs in the usage charge, the pipeline is required to provide partial reservation charge credits during *force majeure* outages.²⁹⁵ The FERC stated that the equitable sharing of risk during a *force majeure* event must approximate either the Safe Harbor or the No-Profit method.²⁹⁶ In *Kern River Gas Transmission*, the FERC directed the pipeline to choose either the Safe Harbor or No-Profit Method after it rejected several proposals in which the pipeline’s sharing of risk was not considered equitable.²⁹⁷

288. *Kern River Gas Transmission Co.*, 138 F.E.R.C. ¶ 61,078 at PP 1-3 (2012).

289. *Id.* at PP 15-17.

290. *Id.* at P 16.

291. *Natural Gas Supply Assoc.*, 135 F.E.R.C. ¶ 61,055 at P 1 (2011), *order on reh’g*, 137 F.E.R.C. ¶ 61,051 (2011).

292. *Id.* at P 27.

293. *Id.* at P 3.

294. *Id.* at P 17.

295. *Northern Natural Gas Co.*, 135 F.E.R.C. ¶ 61,250 at P 18 (2011), *order on reh’g*, 137 F.E.R.C. ¶ 61,202 at PP 13-23 (2011).

296. *Northern Natural Gas Co.*, 137 F.E.R.C. ¶ 61,202 at P 21.

297. *Kern River Gas Transmission*, 129 F.E.R.C. ¶ 61,262 at P 1 (2009), *order on compliance*, 132 F.E.R.C. ¶ 61,111 (2010), *order on compliance*, 135 F.E.R.C. ¶ 61,050 (2011), *order on compliance and reh’g*, 139 F.E.R.C. ¶ 61,044 (2012).

In *Southern Natural Gas Co.*, the FERC reaffirmed that pipelines are not required to provide reservation charge credits for curtailments of service to secondary points.²⁹⁸ The FERC reasoned that reservation charge credits relieve shippers from their contractual obligation to pay for the reservation charges and that such relief should be limited to situations where the pipeline fails to meet its contractual obligation to provide guaranteed service to that shipper.²⁹⁹ The FERC, therefore, concluded that it is reasonable to limit reservation charge credits to a pipeline's failure to provide primary firm service.³⁰⁰ In *Tennessee Gas Pipeline Co.*, the FERC added that a pipeline is not required to provide a reservation charge credit "for interruptions of service from secondary in-path receipt points to primary delivery points."³⁰¹ In *Paiute Pipeline Co.*, the FERC similarly clarified that pipelines may limit reservation charge credits for interruptions on segmented capacity.³⁰² The FERC concluded that "if segmentation occurs on a secondary firm basis, the transaction is not entitled to a reservation charge credit because a firm shipper is only guaranteed delivery to primary points."³⁰³

The FERC clarified that the amount of reservation charge credits the pipeline must give is measured by the amount of service that the shipper nominated to be scheduled by the pipeline but the pipeline was unable to schedule or deliver.³⁰⁴ The FERC has stated that a shipper whose nomination was curtailed in the timely nomination cycle, and is able to nominate its quantities on another pipeline in a subsequent nomination cycle, would not have to re-nominate service on the curtailing pipeline in a subsequent nomination cycle in order to obtain a reservation charge credit from the curtailing pipeline.³⁰⁵ However, the FERC added that "if a shipper does not nominate on another pipeline after it is curtailed in the Timely Cycle, the pipeline may, as a means of preventing gaming, require the shipper to re-submit its nomination through the Evening Nomination Cycle in order to receive reservation charge credits."³⁰⁶ The FERC also clarified that under certain circumstances a pipeline may require that nominated volumes be confirmed by an upstream supplier or downstream pipeline in order to receive a reservation charge credit.³⁰⁷ The FERC explained that "[i]f a shipper's nomination would not have been confirmed by the upstream supplier or the downstream recipient of the gas regardless of the outage on [the pipeline's] system, it is reasonable for [the pipeline] not to provide reservation charge credits with respect to that

298. *Southern Natural Gas Co.*, 135 F.E.R.C. ¶ 61,056 at P 1 (2011), *order on reh'g*, 137 F.E.R.C. ¶ 61,050 (2011).

299. *Southern Natural Gas Co.*, 137 F.E.R.C. ¶ 61,050 at PP 11-17.

300. *Id.* at P 17; *see also Kern River*, 139 F.E.R.C. ¶ 61,044 at PP 11-16.

301. *Tennessee Gas Pipeline Co.*, 139 F.E.R.C. ¶ 61,050 at PP 93-97 (2012).

302. *Paiute Pipeline Co.*, 139 F.E.R.C. ¶ 61,089 at PP 36-37 (2012).

303. *Id.* at P 37.

304. *Southern Natural Gas Co.*, 137 F.E.R.C. ¶ 61,050 at PP 18-19.

305. *See, e.g., Southern Natural Gas Co.*, 135 F.E.R.C. ¶ 61,056 at PP 35-37.

306. *See, e.g., Kern River Transmission Co.*, 135 F.E.R.C. ¶ 61,050 at P 26.

307. *Tennessee Gas Pipeline Co.*, 139 F.E.R.C. ¶ 61,050 at PP 98-101; *see also Rockies Express Pipeline L.L.C.*, 139 F.E.R.C. ¶ 61,275 at PP 9-12 (2012).

nomination.”³⁰⁸ The FERC added, however, that “any exemption from crediting for nominated volumes not ‘confirmed’ must be limited to events not within a pipeline’s control.”³⁰⁹

The FERC has clarified that “the amount of reservation charge credits a pipeline must give in the non-*force majeure* situation is measured by the amount of service which the shipper scheduled but the pipeline was unable to deliver.”³¹⁰ In situations where the pipeline has provided advanced notice of the outage, for example, due to planned or scheduled maintenance, before the shippers submit nominations for the gas day(s) in question, the pipeline may “use an appropriate historical average of usage as a substitute for usage of actual scheduled amounts to determine . . . the shipper’s reservation charge credits.”³¹¹ The FERC added that a pipeline is not required to give a certain amount of advanced notice.³¹² Rather, a pipeline is permitted “to base reservation charge credits on an appropriate average of the shipper’s historical usage if the pipeline gives notice of an outage at any time prior to the timely nomination cycle.”³¹³ The FERC, however, rejected a pipeline’s attempt to limit credits during non-*force majeure* outages to a shipper’s required market deliveries, defined as “the minimum quantities actually required by [the] [s]hipper to serve or otherwise meet its firm market at [p]rimary [d]elivery [p]oints.”³¹⁴

The FERC has ordered pipelines to revise tariff provisions that provide for reservation charge credits in the event the pipeline is unable to make deliveries of at least 98% of a shipper’s scheduled volumes.³¹⁵

In *Southern Natural*, the FERC rejected a tariff provision that would allow the pipeline to not provide reservation charge credits for curtailments when the pipeline is performing seasonal shut-in tests at its storage fields.³¹⁶ The FERC has also rejected an attempt by a pipeline to include in the definition of *force majeure* all service interruptions attributable to government actions.³¹⁷ The FERC explained that pipelines may “include in their definition of *force majeure* events government orders not reasonably within the control of the pipeline.”³¹⁸ The FERC made clear, however, that “[t]esting and maintenance in order to ensure safe and reliable pipeline operation of a pipeline are matters within the pipeline’s control, including when performed in compliance with government orders and regulations,” and thus cannot be included in the definition of *force majeure*.³¹⁹ The FERC also clarified that *force majeure* may include the failure

308. *Tennessee Gas Pipeline Co.*, 139 F.E.R.C. ¶ 61,050 at P 100.

309. *Id.*

310. *Southern Natural Gas Co.*, 135 F.E.R.C. ¶ 61,056 at P 32 (2011).

311. *Id.* at P 33.

312. *Tennessee Gas Pipeline Co.*, 139 F.E.R.C. ¶ 61,050 at P 92 (2012).

313. *Id.*

314. *Kern River Gas Transmission Co.*, 139 F.E.R.C. ¶ 61,044 at PP 43, 45 (2012).

315. *Southern Natural Gas Co.*, 135 F.E.R.C. ¶ 61,056 at P 21, *order on reh’g*, 137 F.E.R.C. ¶ 61,050 at P 34.

316. *Southern Natural Gas Co.*, 135 F.E.R.C. ¶ 61,056, at PP 24, 28.

317. *Tennessee Gas Pipeline Co.*, 139 F.E.R.C. ¶ 61,050 at P 81; *see also Rockies Express*, 139 F.E.R.C. ¶ 61,275 at PP 18-19.

318. *Tennessee Gas Pipeline Co.*, 139 F.E.R.C. ¶ 61,050 at P 81.

319. *Id.* at P 82.

of upstream gas supply facilities to supply nominated quantities of gas, if the downstream pipeline is unable to schedule or provide service for a shipper on its system *solely* because the upstream pipeline was unable to deliver gas to the downstream pipeline.³²⁰

In *Kern River*, the FERC explained that pipelines may specify that “when a shipper has released its capacity to a replacement shipper, . . . the reservation charge credit applicable to the replacement shipper will be the lower reservation rate of the releasing or the replacement shipper.”³²¹

In *Paiute Pipeline*, the FERC clarified that a pipeline may deny reservation charge credits to a shipper that violates an operational flow order (OFO).³²² The FERC reasoned that OFOs are issued “when conditions or events occur that might threaten the operational integrity of the pipeline.”³²³ The FERC stated that denying reservation charge credits to shippers that violate OFOs would provide a further deterrent to shippers whose conduct might harm the pipeline and other shippers.³²⁴

X. Right of First Refusal

In a May 2, 2012 order, the FERC rejected Paiute’s proposal to revise its Right of First Refusal (ROFR) tariff provisions.³²⁵ Paiute proposed to specify that shippers electing to terminate a contract while in its renewal or “evergreen” term would not be eligible for ROFR rights, and if either Paiute or a shipper elected to terminate a service agreement under an evergreen provision, Paiute would not be obligated to include evergreen rights in any contract entered into with the shipper through the ROFR process.³²⁶ The FERC found that this provision “may erode the rights of long-term captive shippers.”³²⁷ Furthermore, the FERC rejected Paiute’s proposal to link its ROFR process to the expansion project development process in various ways, including adding a protocol that no less than thirty days after the issuance of a service continuation notice under its ROFR process, a shipper must either (1) elect to “discontinue service . . . in a manner that permits the use of the associated capacity for the expansion project once the existing service agreement terminates”; or (2) “extend the [existing] full daily reserved capacity of [this] service agreement by matching the applicable term and rate, up to the maximum historical rate that applies to the affected existing capacity holder.”³²⁸

320. *Paiute Pipeline Co.*, 139 F.E.R.C. ¶ 61,089 at PP 30-32.

321. *Kern River Transmission Co.*, 139 F.E.R.C. ¶ 61,044 at P 61; *see also*, *Paiute Pipeline Co.*, 139 F.E.R.C. ¶ 61,089 at P 15.

322. *Paiute Pipeline Co.*, 139 F.E.R.C. ¶ 61,089 at P 25 (2012).

323. *Id.* at P 24.

324. *Id.* at P 25.

325. *Id.* at P 69.

326. Paiute Pipeline Company, Statement of the Nature, the Reasons and the Basis for the Proposed Changes, FERC Docket No. RP12-130-000, at 16 (Nov. 2, 2011).

327. *Paiute Pipeline Co.*, 139 F.E.R.C. ¶ 61,089 at PP 69-72. In this regard, the FERC found Paiute’s proposal contrary to its prior rulings in *Gas Transmission Northwest Corp.*, 117 F.E.R.C. ¶ 61,315 (2006) and *Southern Natural Gas Co.*, 128 F.E.R.C. ¶ 61,211 (2009).

328. *Paiute Pipeline Co.*, 139 F.E.R.C. ¶ 61,089 at P 72.

The FERC found that “tying of the expansion open season process into the ROFR process is contrary to [the FERC’s] policy.”³²⁹ The FERC stated that “pipelines must hold separate open seasons for ROFR capacity and expansion capacity” and that it is “unduly discriminatory” and contrary to shippers’ ROFR rights “to require shippers with ROFR rights, whose contracts expire during a period when an expansion [project] is being planned, to match rates or contract bids in an expansion open season.”³³⁰

Y. Scheduling Priority

On April 19, 2012, the FERC issued an order on rehearing and clarification in Tennessee’s NGA section 4 rate proceeding.³³¹ The order addressed several non-rate issues raised on rehearing and in protests, including scheduling priority, that were reserved for resolution by the FERC in the settlement of Tennessee’s rate case.³³² Upholding an order issued following a technical conference,³³³ the FERC rejected rehearing requests filed by local distribution companies who supported Tennessee’s proposal to elevate the scheduling priority of within-path transportation from secondary receipt points to primary delivery points to the same level as primary-to-primary transportation, and ahead of the priority for within-path primary receipt points to secondary delivery points.³³⁴ Relying on Order No. 636-B,³³⁵ the FERC ruled that primary-to-primary must have the highest priority.³³⁶ The FERC reaffirmed its prior rejection of Tennessee’s claim that the policy established in Order No. 637, distinguishing between in-the-path and out-of-path transactions, supported the higher scheduling priority for in-path secondary receipt points to primary delivery points over in-path primary receipt points to secondary delivery points.³³⁷ However, reversing its position in the Technical Conference Order, the FERC clarified that, if deemed reasonable, pipelines may establish higher scheduling priority for secondary receipt point to primary delivery point transactions than for primary receipt point to secondary delivery point transactions.³³⁸

Tennessee’s section 4 filing also proposed to schedule firm secondary service by price.³³⁹ On rehearing, the FERC reversed its position in the Technical Conference Order that “scheduling by absolute price would not allocate firm capacity to the shipper that values it the most.”³⁴⁰ Although Tennessee’s proposal was unjust and unreasonable because it discriminated

329. *Id.* at P 69.

330. *Id.* at PP 70-71.

331. *Tennessee Gas Pipeline Co.*, 139 F.E.R.C. ¶ 61,050 at PP 1-2 (2012).

332. *Id.*; *Tennessee Gas Pipeline Co.*, 137 F.E.R.C. ¶ 61,182 at P 3 (2011) (Settlement Order).

333. *Tennessee Gas Pipeline Co.*, 135 F.E.R.C. ¶ 61,208 (2011) (Technical Conference Order).

334. *Tennessee Gas Pipeline Co.*, 139 F.E.R.C. ¶ 61,050 at P 13.

335. Order No. 636-B, *Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation; and Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol*, 61 F.E.R.C. ¶ 61,272, at p. 62,013 (1992).

336. *Tennessee Gas Pipeline Co.*, 139 F.E.R.C. ¶ 61,050 at PP 13, 15 (2012).

337. *Id.* at P 19.

338. *Id.* at P 22.

339. *Id.* at P 32.

340. *Id.* at P 40.

against maximum rate short haul shippers, the FERC confirmed that pipelines are not prohibited from scheduling firm secondary transactions by price.³⁴¹ Pipelines may schedule firm secondary capacity “by either the highest percentage of the applicable maximum rate or by the highest absolute price” provided that scheduling by absolute price is subject to a caveat that any shippers paying the maximum rate will be scheduled ahead of shippers paying a discounted rate.³⁴² Discounted rate shippers, including capacity release replacement shippers, may increase their rate to the maximum rate in order to flow on a particular day.³⁴³ To determine scheduling priority involving firm secondary released capacity, “pipelines may propose [using] either the releasing shipper’s or replacement shipper’s rate.”³⁴⁴ The FERC, however, attached three conditions to the use of a releasing shipper’s rate for secondary scheduling. First, if the releasing shipper increases its rate to gain *pro rata* scheduling of its secondary capacity, the pipeline must credit the replacement shipper, not retain the payment.³⁴⁵ Second, tariffs must address how to value index and formula rates in determining scheduling priorities.³⁴⁶ Finally, if a replacement shipper is paying above the maximum rate, it will be treated as a maximum rate shipper for scheduling purposes.³⁴⁷

Z. Termination

On March 16, 2012, the FERC accepted Dominion Transmission, Inc.’s (DTI) proposal to revise its form of service agreement under Rate Schedule GSS to insert bracketed language providing that short-term storage service agreements will remain in effect on a year-to-year basis after their primary term until either party terminates.³⁴⁸ The bracketed language also will add a blank to specify the number of months of notice the terminating party must provide.³⁴⁹ The notice length will “equal the primary term of the agreement.”³⁵⁰ DTI previously required 24-months’ notice and claimed in its tariff filing that such notice was unworkable in the context of a two year storage agreement.³⁵¹ The FERC found that the revised provision addresses shipper concerns regarding parity between long-term and short-term shippers.³⁵²

AA. Upstream Capacity

On January 20, 2012, following a technical conference, the FERC accepted Columbia Gas’s out-of-cycle Transportation Cost Rate Adjustment (TCRA)

341. *Id.*

342. *Id.* at P 41.

343. *Id.* (for discount shippers); *Id.* at P 56 (for capacity release replacement shippers).

344. *Id.* at P 41.

345. *Id.* at P 55.

346. *Id.*

347. *Id.* at P 56.

348. *Dominion Transmission, Inc.*, 138 F.E.R.C. ¶ 61,198 at PP 1-2 (2012). DTI proposed a month-to-month rollover, but changed its position following a protest by a shipper. *Id.* at PP 1, 5.

349. *Id.* at P 6.

350. *Id.* at P 5.

351. *Id.* at P 2.

352. *Id.* at P 7.

filing submitted to recover increases in off-system transportation costs incurred to fill Columbia Gas's northern Ohio storage fields attributable to changes in system utilization as a result of Marcellus Shale production.³⁵³ The FERC found that recovering the costs under the TCRA was consistent with the TCRA mechanism in Columbia's tariff as well as recent orders on the mechanism.³⁵⁴ Because the costs are eligible for recovery under the TCRA, the FERC reasoned that it could only reject or require Columbia Gas to share in the costs if they were found to be imprudent and the record did not support such a finding.³⁵⁵ However, the FERC ruled that its approval of the costs did not constitute a finding that Columbia Gas's acquisition of upstream capacity to flow gas to northern Ohio was a long-term solution to Columbia Gas's operational issue.³⁵⁶

On May 22, 2012, the FERC approved Columbia Gas's proposal to establish an Operational Transaction Rate Adjustment (OTRA) to recover the cost of operational purchases of gas to maintain sufficient flowing supply into northern Ohio.³⁵⁷ Under the interim mechanism effective through March 31, 2014, Columbia Gas will make sales of equivalent quantities elsewhere on its system and the OTRA will be filed semi-annually to recover any pricing differences.³⁵⁸ Based on current market conditions, the purchases and sales under the OTRA will reduce costs to shippers compared to the purchase of upstream pipeline capacity to serve northern Ohio.³⁵⁹ The FERC granted Columbia a waiver of the independent functioning requirement of the Standards of Conduct under section 284.286 of the FERC's regulations to facilitate the purchases and sales³⁶⁰ and also confirmed that the purchases and sales do not constitute prohibited buy/sell arrangements.³⁶¹

III. INFRASTRUCTURE

A. Pipelines

The FERC authorized (i) National Fuel to construct and operate its proposed Northern Access Project, and (ii) Tennessee to abandon and upgrade certain compression facilities on the Niagara Spur Loop Line as part of its

353. *Columbia Gas Transmission, LLC*, 138 F.E.R.C. ¶ 61,044 at PP 1, 4 (2012); *Columbia Gas Transmission, LLC*, 136 F.E.R.C. ¶ 61,062 (2011) (Suspension Order).

354. *Columbia Gas Transmission, LLC*, 138 F.E.R.C. ¶ 61,044 at PP 17-18 (citing *Columbia Gas Transmission, LLC*, 129 F.E.R.C. ¶61,037 at PP 29-33 (2009) (noting that "section 36.1(a) of Columbia's GT&C defines the Operational 858 costs that may be recovered through the TCRA broadly as 'costs incurred for the transmission and compression of gas by others . . . including amounts paid to upstream pipelines for contracts . . . utilized in Transporter's post-restructuring operations'")).

355. *Id.* at P 20.

356. *Id.* at P 48.

357. *Columbia Gas Transmission, LLC*, 139 F.E.R.C. ¶ 61,141 at P 1 (2012).

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

359. *Id.* at P 17.

360. *Id.* (the limited waiver applies only to transmission function employees engaged in activities directly related to purchases and sales under the OTRA mechanism; these employees may not perform any other marketing function activities).

361. *Id.* at P 23.

Station 230C Project.³⁶² Together, the two projects enable “the transportation of Marcellus Shale production into Canada.”³⁶³

The FERC granted National Fuel a pre-determination of rolled-in rate treatment for the cost of the Northern Access facilities in its next rate case, based on a long-term contract with a firm shipper that would produce greater revenues than the cost of facilities over the term, thus averting any subsidy by existing customers.³⁶⁴ In contrast, the FERC denied Tennessee’s request for a pre-determination of rolled-in rate treatment, as it had no contracts in place to use the new capacity and thus was not able to demonstrate that existing customers would not subsidize the project.³⁶⁵

In reviewing the environmental aspects of the project, the FERC rejected the objections of certain neighboring landowners to National Fuel’s proposed new East Aurora Compressor Station that the compressors should instead be located at National Fuel’s existing Concord Compressor Station.³⁶⁶ In an order issued April 13, 2012, the FERC denied rehearing and a request for stay, reaffirming its previous determination that the new East Aurora Compressor location was the environmentally preferable option for placement of compression facilities.³⁶⁷

The FERC authorized CNYOG to construct and operate the 39-mile, 30-inch MARC I pipeline and related compression (MARC I Project), extending from CNYOG’s facilities in Bradford County, Pennsylvania to an interconnection with Transco near Leidy in Lycoming County, Pennsylvania.³⁶⁸ Capacity in the MARC I pipeline was fully subscribed under precedent agreements with three shippers who committed to ten-year firm transportation service agreements.³⁶⁹ The FERC found that the MARC I pipeline was justified under the tests outlined in its certificate policy statement,³⁷⁰ in that the pipeline would not be subsidized by existing customers, would not have an adverse impact on other pipelines in the market and on their captive shippers, and would have limited impact on landowners and communities along its route.³⁷¹

The FERC made several adjustments to CNYOG’s proposed rates and tariff. It ordered CNYOG to file for an adjustment of its rates for Firm Wheeling service over existing facilities associated with its Stagecoach Storage Project to avoid possible double recovery of costs sought to be recovered in services to be

362. *National Fuel Gas Supply Corp.*, 137 F.E.R.C. ¶ 61,054 at P 1 (2011), *reh’g denied*, 139 F.E.R.C. ¶ 61,037 (2012).

363. *Id.*

364. *Id.* at PP 10, 23, 56.

365. *Id.* at PP 37, 56.

366. *Id.* at P 51.

367. *National Fuel Gas Supply Corp.*, 139 F.E.R.C. ¶ 61,037 at PP 2, 15 (2012).

368. *Central N.Y. Oil and Gas Co.*, 137 F.E.R.C. ¶ 61,121 at PP 1-2, 7 (2011), *reh’g denied*, 138 F.E.R.C. ¶ 61,104 at P 1 (2012), *aff’d by summary order*, Coalition for Responsible Growth and Resource Conservation v. FERC, No. 12-566-ag, 2012 WL 2097249 (2d Cir. June 12, 2012) (slip copy).

369. *Central N.Y. Oil and Gas Co.*, 137 F.E.R.C. ¶ 61,121 at P 8.

370. *Certification of New Interstate Natural Gas Pipelines Facilities*, 88 F.E.R.C. ¶ 61,227 (1999), *clarified*, 90 F.E.R.C. ¶ 61,128, *further clarified*, 92 F.E.R.C. ¶ 61,094 (2000).

371. *Central N.Y. Oil and Gas Co.*, 137 F.E.R.C. ¶ 61,121 at PP 15-17.

provided by the MARC I pipeline.³⁷² It reduced CNYOG's proposed accrual of AFUDC by \$87,720 to remove costs associated with certain joint facilities already placed in service in connection with another project.³⁷³ The FERC also rejected proposed tariff provisions related to creditworthiness requirements for possible expansion projects, noting that such requirements should not be included in the tariff but in precedent agreements related to the expansion capacity.³⁷⁴

The MARC I Project faced substantial environmental challenges by Earthjustice, the National Audubon Society, Trout Unlimited, the Lower Susquehanna Riverkeepers, and the United States Environmental Protection Agency (EPA) under the National Environmental Policy Act (NEPA).³⁷⁵ These parties claimed, *inter alia*, that the principal issue in scoping was "development of natural gas from the Marcellus Shale in Pennsylvania, and the need to consider the cumulative impacts of such development"³⁷⁶ in determining whether to authorize the project. Earthjustice, for example, claimed that the FERC's environmental analysis (EA) should consider existing and reasonably foreseeable impacts from Marcellus development, including other pipelines and gathering facilities.³⁷⁷ In addition, these parties urged the FERC to conduct a more rigorous environmental review by preparing an Environmental Impact Statement (EIS) instead of an EA.³⁷⁸

The FERC rejected these environmental challenges.³⁷⁹ While the EA addressed the cumulative impacts of other natural gas pipelines and natural gas facilities that would be associated with the MARC I Project that are not subject to the FERC's jurisdiction, as well as unrelated projects that are either in place, under construction, or proposed in the project area, the FERC ruled that an analysis of cumulative impacts of development of the Marcellus Shale in northeast Pennsylvania and beyond was not required to satisfy NEPA.³⁸⁰ Finally, the FERC rejected claims by the EPA and Earthjustice that the EA should have addressed an alternative route.³⁸¹

On February 13, 2012, the FERC denied Earthjustice's request for rehearing and dismissed as moot its application for stay pending rehearing.³⁸² On appeal, the United States Court of Appeals for the Second Circuit, by

372. *Id.* at P 21.

373. *Id.* at P 25.

374. *Id.* at P 34.

375. *Id.* at P 49.

376. *Id.* at P 48.

377. *Id.*

378. *Id.* at P 50.

379. *Id.* at P 94.

380. The EA rejected the need for a cumulative impacts analysis on the grounds that the widespread nature and uncertain timing of gas well drilling relative to construction of the MARC I Project make it difficult to identify and quantify cumulative impacts: since the development of natural gas reserves in the formation is expected to take 20 to 40 years due to economics and other factors, the exact location, scale, and timing of future Marcellus Shale upstream facilities that could potentially contribute to cumulative impacts in the project area is unknown at this time.

Id. at P 60.

381. *Id.* at PP 125-27.

382. *Central N.Y. Oil and Gas Co.*, 138 F.E.R.C. ¶ 61,104 at P 21 (2012).

summary order,³⁸³ denied a petition for review of the FERC's orders by the environmental interests.³⁸⁴ The court concluded that the FERC's determination not to prepare an EIS was not arbitrary and capricious and that its analysis of cumulative impacts was sufficient.³⁸⁵ The court noted that the FERC "reasonably concluded that the impacts of . . . [Marcellus Shale] are not sufficiently causally-related to the project to warrant a more in-depth analysis."³⁸⁶

In *Texas Eastern Transmission, LP and Algonquin Gas Transmission, LLC*, the FERC authorized Texas Eastern and Algonquin to undertake a \$860 million project that will bring 800,000 Dth/day of firm transportation service from numerous upstream production fields, including the Marcellus Shale, into Manhattan, New York (NJ - NY Project).³⁸⁷ The project would involve abandonment, replacement, and construction of pipeline facilities in six counties in New Jersey and three counties in New York, along with the lease of capacity on Algonquin's pipeline system by Texas Eastern.³⁸⁸ The FERC concluded that the proposed replacement of nearly nine miles of 12-, 20-, and 24-inch diameter pipeline with 30- and 42-inch diameter pipeline "in order to accommodate the incremental expansion volumes while continuing to meet the requirements of Texas Eastern's existing customers" was in the public convenience or necessity.³⁸⁹ The FERC found "strong evidence that the market also believes the project is needed."³⁹⁰ The entire 800,000 Dth/day capacity has been subscribed for 15-20 years under precedent agreements with three companies as New York moves to replace heavy heating oil with a cleaner burning, and less costly, heating fuel source.³⁹¹ The FERC also noted the competitive benefit the project would have in New York.³⁹²

Addressing environmental objections, particularly the argument that the project will prompt additional shale gas exploration and development, the FERC found, similar to *Central New York Oil and Gas Co.*, that the project is driven primarily by the region's state and local agencies' curtailment of continued use of heavy fuel oil, not specifically by shale gas development.³⁹³ As for safety issues raised in the wake of the 2010 San Bruno, California pipeline explosion, the FERC noted that Texas Eastern "plans to put in place several measures that exceed [Department of Transportation's] requirements."³⁹⁴

383. According to Rule 32.1.1 of the Second Circuit's Local Rules, "rulings by summary order do not have precedential effect." However, parties may still cite such orders provided they comply with additional procedural requirements. 2D Cir. R. 32.1.1.

384. *Coalition for Responsible Growth and Resource Conservation v. FERC*, No. 12-566-ag, 2012 WL 2097249 (2d Cir. June 12, 2012) (slip copy).

385. *Id.* at *1.

386. *Id.* at *2.

387. *Texas Eastern Transmission, LP*, 139 F.E.R.C. ¶ 61,138 at PP 1, 5, 9 (2012).

388. *Id.* at PP 5, 7.

389. *Id.* at P 26.

390. *Id.* at P 22.

391. *Id.* at PP 20, 22-23.

392. *Id.* at P 25.

393. *Id.* at P 73.

394. *Id.* at P 86.

In *Kern River Gas Transmission Co.*, the FERC authorized Kern River to construct and operate pipeline facilities including an 8.6 mile 8-inch diameter lateral to its mainline in eastern San Bernardino County in California to provide natural gas service to a rare earth mine and production facility for use as electric generator fuel.³⁹⁵ Several California environmental watch groups claimed the project would have an impact on a variety of desert animal and plant species.³⁹⁶ The FERC found that no specific mitigation was required in connection with the potential presence of a number of these animal species, nor was mitigation required to contain the spread of invasive weeds, as these plant species were already present and pervasive in the area.³⁹⁷ The EA for the project contemplated a special treatment plan for the Rusby's desert-mallow, which would include transplant of any of these plants to an adjacent location and care following the transplant for an appropriate period, as determined by a qualified botanist.³⁹⁸ As for the project's potential impact on the desert tortoise, the FERC stated that it was engaged in formal consultations with the U.S. Fish & Wildlife Service, which will lead to the latter's issuance of a biological opinion on "whether the project is likely to jeopardize the continued existence of this [Endangered Species Act] listed species."³⁹⁹ The FERC's order contains the condition that construction may not begin until these consultations are concluded.⁴⁰⁰

In other orders not raising significant issues, the FERC authorized (i) Texas Eastern to modify its mainline system in the Marcellus region between its Holbrook and Marietta Compressor Stations in Greene and Lancaster Counties, Pennsylvania to increase transportation capacity by 200,000 Dth/day from receipt points in eastern Ohio and western Pennsylvania to areas in York and Lancaster Counties;⁴⁰¹ (ii) Columbia Gas to construct a 2.47-mile, 24-inch lateral pipeline to serve a new Virginia Electric Power Company (VEPCO) power generation facility under construction in Warren County, Virginia that, together with new mainline backhaul capacity, will allow VEPCO to transport on a firm basis up to 224,000 Dth/day from April to September from Columbia Gas's delivery point in Leach, Kentucky, and up to 246,000 Dth/day from October through May via backhaul from Columbia Gas's interconnect with Transco in Montgomery County, Maryland;⁴⁰² and (iii) National Fuel to construct, operate and abandon facilities to implement its Line N 2012 Expansion Project designed to create an additional 164,000 MMBtu/day of southbound transportation capacity on its Line N in Washington County, Pennsylvania.⁴⁰³

395. *Kern River Gas Transmission Co.*, 138 F.E.R.C. ¶ 61,037 (2012).

396. *Id.* at P 19.

397. *Id.* at P 66.

398. *Id.* at PP 48-49.

399. *Id.* at P 37.

400. *Id.* at app. B, Environmental Condition 11.

401. *Texas Eastern Transmission, LP*, 137 F.E.R.C. ¶ 61,140 at PP 1, 3 (2011).

402. *Columbia Gas Transmission, LLC*, 138 F.E.R.C. ¶ 61,205 at PP 1, 3 (2012).

403. *National Fuel Gas Supply Corp.*, 138 F.E.R.C. ¶ 61,224 at PP 1, 6 (2012).

B. Storage Projects

The FERC granted a certificate to Golden Triangle Storage, Inc. (Golden Triangle) for the expansion of existing storage facilities and to apply its existing market-based rate authority to the expansion facilities.⁴⁰⁴ Golden Triangle proposed to construct two new salt dome storage caverns at its existing storage facilities in Jefferson County, Texas (increasing the total project capacity to 49.38 Bcf), and to offer increased quantities of storage and hub services.⁴⁰⁵ Golden Triangle requested continued authorization to charge market-based rates for the expansion capacity.⁴⁰⁶ The FERC found no adverse impact on existing customers, existing storage providers and their captive customers, or landowners, and granted the requested certificate.⁴⁰⁷ The FERC also approved Golden Triangle's authority to charge market-based rates for the expansion capacity, finding that Golden Triangle did not possess market power in the relevant market areas.⁴⁰⁸

The FERC approved a request by National Fuel under its blanket certificate to drill two open-hole wells to increase deliverability by 9.9 MMcf/day at the Colden Storage Field, and to construct well lines to connect the new wells to existing storage field pipelines.⁴⁰⁹ The request was protested by two landowners claiming the project would diminish their property value, making authorization to construct the requested facilities under the blanket certificate no longer automatic.⁴¹⁰ Because the proposed facilities were located entirely within the certificated boundaries of the project, with no above-ground operations on the protestors' properties, the FERC denied the protest and authorized the facilities under the existing blanket certificate.⁴¹¹

The FERC approved an application by Perryville Gas Storage LLC (Perryville) to amend its certificate for the Crowville Project to expand its working gas capacity and drill additional freshwater supply and brine disposal wells.⁴¹² Additionally, the FERC confirmed Perryville's authority to continue charging market based rates.⁴¹³ The Crowville facilities, which include two salt domes, were certificated in 2010 and are currently under construction.⁴¹⁴ Perryville proposed to increase working gas capacity from originally approved 7.5 to 10 Bcf because it received interest for almost all of the capacity in the two caverns.⁴¹⁵ It also planned to drill additional supply and disposal wells necessary to meet the needs of the expanded facilities.⁴¹⁶ The FERC granted the certificate amendment as consistent with the Certificate Policy Statement, finding the

404. *Golden Triangle Storage, Inc.*, 138 F.E.R.C. ¶ 61,036 at P 1 (2012).

405. *Id.* at P 4.

406. *Id.* at P 1.

407. *Id.* at PP 14-15.

408. *Id.* at P 19.

409. *National Fuel Gas Supply Corp.*, 138 F.E.R.C. ¶ 61,017 at PP 1, 5 (2012).

410. *Id.* at PP 9-10.

411. *Id.* at P 16.

412. *Perryville Gas Storage LLC*, 137 F.E.R.C. ¶ 61,160 at PP 2-3 (2011).

413. *Id.*

414. *Id.* at P 5.

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

416. *Id.* at P 7.

expansion would provide benefits by enhancing storage options, with minimal adverse effects on other storage providers.⁴¹⁷ The FERC also approved Perryville's continued use of market-based rates. The FERC noted that Perryville had not held an open season for the additional capacity covered by the amendment, however, which the FERC ordered Perryville to do pursuant to the FERC's open-season policy.⁴¹⁸

The FERC issued a certificate to Dominion Transmission, Inc. (DTI) to expand the project boundary and construct a protective buffer zone around its Woodhull Storage Pool located in Steuben County, New York.⁴¹⁹ The FERC agreed that the buffer zone was required to protect the project against a potential breach due to hydraulic fracturing used in Marcellus Shale production, notwithstanding the current New York moratorium on Marcellus Shale drilling.⁴²⁰ DTI indicated that it would not construct new facilities under its proposal, but would incur costs related to acquiring the land that would comprise the buffer zone.⁴²¹ Accordingly, DTI requested permission to roll-in costs associated with creating the buffer in its next section 4 rate proceeding.⁴²²

Over objections, the FERC granted a pre-determination of rolled-in rate treatment, but noted that customers will have the opportunity to examine project costs in DTI's future rate proceeding.⁴²³ The FERC also noted that if negotiations between DTI and landowners failed, any proceeding to acquire the land through eminent domain would take into consideration the fair market value of the property rights, including the value of any mineral rights, in any compensation determination.⁴²⁴ Finally, the FERC ordered DTI and National Fuel to resolve any issues of overlapping buffer zones (as claimed by National Fuel) and file an agreement with the FERC demonstrating the parties intent to protect the integrity of their respective storage fields.⁴²⁵

The FERC's Office of Energy Projects (OEP) denied a request by Chestnut Ridge Storage LLC (Chestnut Ridge) for an extension of time to complete construction on the Junction Natural Gas Storage Project.⁴²⁶ In August 2009, the FERC granted Chestnut Ridge a certificate to construct the project with a completion date of August 2011.⁴²⁷ In August 2011, Chestnut Ridge asked to extend the project completion date to August 2014 citing the state of the economy and changes in the natural gas storage market that delayed the project.⁴²⁸ OEP denied the request for an extension, finding that Chestnut Ridge failed to demonstrate any improvement in the outlook for the project or that project financing was available, and determined that Chestnut Ridge should have

417. *Id.* at P 15.

418. *Id.* at PP 21-22.

419. *Dominion Transmission, Inc.*, 137 F.E.R.C. ¶ 61,132 at P 1 (2011).

420. *Id.* at PP 5, 43.

421. *Id.* at P 21.

422. *Id.* at P 11.

423. *Id.* at P 22.

424. *Id.* at PP 25-27.

425. *Id.* at PP 44-46.

426. *Chestnut Ridge Storage LLC*, 137 F.E.R.C. ¶ 62,106 (2011).

427. *Id.* at 1-2.

428. *Id.*

demonstrated more progress towards completion in the two years since the certificate had been issued.⁴²⁹ The FERC invited Chestnut Ridge to submit an updated application if improved circumstances induced future development of the project.⁴³⁰

The FERC granted a certificate to Tricor Ten Section Hub, LLC (Tricor) for the construction and operation of a new interstate natural gas storage facility located in Kern County, California to provide approximately 22.4 Bcf of working gas capacity.⁴³¹ The FERC determined there would be no negative impacts on existing storage providers or their captive customers, and that the proposed facilities would increase competitive alternatives for storage options to pipelines and their customers.⁴³²

With respect to Tricor's request to charge market based rates, the FERC rejected the scope of the relevant geographic market initially proposed by Tricor for its market power analysis, which included most of the western United States.⁴³³ The FERC noted that the appropriate market should only include the area with storage facilities that are directly connected to the pipeline with which the project will interconnect. Reevaluating the market power findings based on storage facilities located in California, Texas, New Mexico, and Utah, the FERC noted that Tricor exceeded the market power threshold under the Herfindahl-Hirschman Index.⁴³⁴ However, because of mitigating circumstances that would prevent Tricor from exercising market power, the FERC granted market-based rate authority.⁴³⁵

The FERC granted certificates authorizing a lease arrangement between Peoples Natural Gas Company LLC (Peoples) and Rager Mountain Storage Company LLC (Rager Mountain).⁴³⁶ Peoples sought a limited-jurisdiction certificate to lease 2.0 Bcf of working gas capacity at its Rager Mountain storage facility to Rager Mountain. Simultaneously, Rager Mountain sought approval to lease the 2.0 Bcf of capacity and 45,000 Mcf/day of deliverability and to offer open access interstate gas storage services at market-based rates using the leased capacity.⁴³⁷ The FERC found that Rager Mountain's request satisfied the requirements of the Certificate Policy Statement but noted that lease arrangements require additional consideration.⁴³⁸ The FERC found that the lease agreement between Peoples and Rager Mountain satisfied those requirements; namely, that there are benefits from using a lease arrangement, the lease payments are no greater than the lessor's firm transportation rates for comparable service, and existing customers are not harmed by the lease arrangement.⁴³⁹ Although Peoples did not have in place tariff provisions for the

429. *Id.* at 2-3.

430. *Id.* at 5.

431. *Tricor Ten Section Hub, LLC*, 136 F.E.R.C. ¶ 61,242 at PP 1-2 (2011).

432. *Id.* at P 21.

433. *Id.* at P 33.

434. *Id.* at PP 33, 38.

435. *Id.* at P 38.

436. *Rager Mountain Storage Co.*, 136 F.E.R.C. ¶ 61,151 at PP 1-2 (2011).

437. *Id.* at P 1.

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

439. *Id.* at PP 33-35.

services it proposed to offer to Rager Mountain, the FERC approved the lease payments because they are based on People's costs associated with the leased capacity and because Rager would be providing storage services at market-based rates.⁴⁴⁰ The FERC concluded that Rager Mountain would lack significant market power and approved its request to charge market-based rates.⁴⁴¹

C. LNG Projects

In *Pacific Connector Gas Pipeline, LP and Jordan Cove Energy Project, L.P.*, the FERC vacated, without prejudice, Jordan Cove Energy Project, L.P.'s (Jordan Cove) NGA section 3 authorization to site, construct, and operate a LNG import terminal in Coos County, Oregon.⁴⁴² Along with Jordan Cove's section 3 authorization, the FERC had previously granted NGA section 7(c) authorization to Pacific Connector Gas Pipeline, LP to construct an associated pipeline from the terminal to a point near the Oregon-California border.⁴⁴³ In February 2012, Jordan Cove notified the FERC that, due to current market conditions, it no longer planned to construct the import terminal, but "would add the equipment necessary for import of LNG should the natural gas market conditions change in the future."⁴⁴⁴ In vacating the import authorization, the FERC held that the FERC's "ability to rely on the usually valid assumption that a project sponsor will not go forward with construction of a project (in this case, an import terminal) for which there is no market is compromised here."⁴⁴⁵ The order was accompanied by a sharp dissent by Commissioner Philip Moeller.

In *Sabine Pass Liquefaction, LLC and Sabine Pass LNG, L.P.*, the FERC granted Sabine Pass NGA section 3 authorization to site, construct, and operate facilities to liquefy and export up to 2.2 billion cubic feet per day, or 16 million tonnes per annum, of domestically produced natural gas at Sabine Pass's existing LNG terminal in Cameron Parish, Louisiana (Liquefaction Project).⁴⁴⁶ Upon completion, the Sabine Pass terminal would be the first bi-directional LNG facility in the United States capable of importing and re-gasifying foreign-sourced LNG, as well as liquefying and exporting domestically produced natural gas as LNG.⁴⁴⁷ As highlighted by the FERC, the Liquefaction Project would allow customers to import LNG when faced with high domestic prices and liquefy and export natural gas when prices are higher outside the United States.⁴⁴⁸

The FERC found that the Liquefaction Project could be constructed and operated safely, with minimal environmental impacts; rejecting environmental concerns raised by the Sierra Club regarding impacts on air emissions.⁴⁴⁹ The

440. *Id.* at P 34.

441. *Id.* at P 45.

442. *Pacific Connector Gas Pipeline, LP and Jordan Cove Energy Project, L.P.*, 139 F.E.R.C. ¶ 61,040 at PP 1, 27 (2012).

443. *Id.* at P 1.

444. *Id.* at P 21.

445. *Id.* at P 22.

446. *Sabine Pass Liquefaction, LLC and Sabine Pass LNG, L.P.*, 139 F.E.R.C. ¶ 61,039 at PP 1-3 (2012).

447. *Id.* at P 6.

448. *Id.*

449. *Id.* at PP 29, 62.

FERC also rejected as speculative other interveners' claims of the cumulative impacts of other proposed liquefaction facilities on air emissions and greenhouse gas emissions, and held that the environmental impacts "are relatively small in number and well-defined."⁴⁵⁰ Further, the FERC determined that the Liquefaction Project is not inconsistent with the public interest by deferring to the U.S. Department of Energy's public interest findings in the Liquefaction Project's export authorization.⁴⁵¹ Further, the FERC ordered Sabine Pass to adhere to fifty-five mitigation conditions, as well as complete construction and commence service within five years of the date of the authorization.⁴⁵²

In *Crown Landing LLC and Texas Eastern Transmission, LP*, the FERC vacated Crown Landing LLC's (Crown Landing) NGA section 3 authorization to construct an LNG facility in Gloucester County, New Jersey, and Texas Eastern's NGA section 7 authorization to construct the associated pipeline.⁴⁵³ The FERC required both Crown Landing and Texas Eastern to place the facilities into service within three years of the date of authorization.⁴⁵⁴ In January 2012, Crown Landing notified the FERC that it chose to terminate its project and requested the FERC to vacate its authorization.⁴⁵⁵ Since Texas Eastern had not yet constructed facilities and commenced service by the required timeframe, the FERC vacated Texas Eastern's authorization and granted Crown Landing's request.⁴⁵⁶

In *Dominion Cove Point LNG, LP*, after convening a technical conference to examine issues more closely, the FERC accepted certain proposed tariff changes that would, among other things, allow a firm import shipper to prepay its share of Dominion Cove Point LNG, LP's (Cove Point) anticipated future under-recoveries through LNG tendered at the terminal.⁴⁵⁷ The FERC also approved, with modification, Cove Point's scheduling flexibility revisions, in light of Cove Point's showing of shippers' inefficient use of the terminal and inaccurate scheduling that impacted the scheduling of other services.⁴⁵⁸ Further, acting under its NGA section 5 authority, the FERC required Cove Point to modify its existing tariff by providing for reservation charge credits during *force majeure* and *non-force majeure* periods.⁴⁵⁹ The FERC held that FERC "policy requires that pipelines and shippers share the risk of *force majeure* service interruptions because such service interruptions are no-fault occurrences."⁴⁶⁰

The FERC also acknowledged the Stipulation and Agreement of Interim Partial Settlement (Interim Partial Settlement) submitted by Cove Point regarding proposed tariff changes for OFOs requiring the importation of LNG

450. *Id.* at P 29.

451. *Id.* at PP 28-30.

452. *Id.* at P 120.

453. *Crown Landing LLC and Texas Eastern Transmission, LP*, 138 F.E.R.C. ¶ 61,132 (2012).

454. *Id.* at P 2.

455. *Id.* at P 4.

456. *Id.*

457. *Dominion Cove Point LNG, LP*, 137 F.E.R.C. ¶ 61,158 at PP 3, 13-14 (2011).

458. *Id.* at PP 23-24.

459. *Id.* at PP 44-46.

460. *Id.* at P 7.

for operational purposes.⁴⁶¹ The tariff revisions were prompted by a decline in LNG shipments to Cove Point, threatening the operational integrity and performance capability of its system.⁴⁶² The proposed changes were previously rejected by the FERC, since an operational purchase of LNG to keep certain facilities cooled to the requisite temperature is a cost of providing jurisdictional service.⁴⁶³ Cove Point could also make a limited NGA section 4 filing to include a cost-recovery mechanism in its tariff.⁴⁶⁴ The Interim Partial Settlement provides for a limited one-time operational purchase of LNG by Cove Point, and applies only to the delivery of one LNG cargo to the Cove Point terminal.⁴⁶⁵

In *Pivotal LNG, Inc.*, the FERC dismissed Pivotal LNG, Inc.'s (Pivotal) application for NGA section 7(c) authorization to transport and sell natural gas in interstate commerce.⁴⁶⁶ Pivotal proposed that, after acquiring an existing LNG peaking facility from the Utilities Board of the City of Trussville, Alabama (Trussville), "it would operate the facility to liquefy and store natural gas received . . . for subsequent sale in liquid form."⁴⁶⁷ Pivotal planned to sell any boil-off and tail gas to Trussville and make deliveries directly into the Trussville system. In particular, Pivotal proposed to transport the gas through a pipeline to its interconnection with Southern, a pipeline that Pivotal would re-commission to the extent its LNG facility generated more boil-off and/or tail gas than Trussville could absorb for delivery.⁴⁶⁸ The FERC dismissed Pivotal's application after Pivotal informed the FERC that it would not recommission the pipeline, since all boil-off and tail gas would either be delivered to the Trussville system by truck or consumed within the Trussville system.⁴⁶⁹

In *Calypso U.S. Pipeline, LLC*, the FERC vacated Calypso U.S. Pipeline, LLC's (Calypso) NGA section 7(c) authorization "to, among other things, construct and operate natural gas pipeline facilities from the U.S./Bahamas Exclusive Economic Zone (EEZ) boundary to a point on the Florida coast."⁴⁷⁰ The FERC also vacated the Presidential Permit issued to Calypso to site, construct, and operate natural gas facilities at the U.S.-EEZ boundary for the importation of natural gas.⁴⁷¹ In August 2011, Calypso informed the FERC that it planned to terminate its proposed project and would surrender its authorizations and Presidential Permit.⁴⁷²

In *Southern LNG Co.*, the FERC vacated, in part, Southern LNG Company, L.L.C.'s (Southern LNG) NGA section 3 authorization.⁴⁷³ In September 2007, Southern LNG received section 3 authorization to *inter alia* "expand the storage

461. *Id.* at P 3.

462. *Id.*

463. *Id.* at P 5; see also *Dominion Cove Point LNG, LP*, 135 F.E.R.C. ¶ 61,261 (2011).

464. *Dominion Cove Point LNG, LP*, 135 F.E.R.C. ¶ 61,261 at P 42.

465. *Dominion Cove Point LNG, LP*, 137 F.E.R.C. ¶ 61,158 at P 7.

466. *Pivotal LNG, Inc.*, 137 F.E.R.C. ¶ 62,108 at 1 (2011).

467. *Id.* at 2.

468. *Id.*

469. *Id.* at 2-3.

470. *Calypso U.S. Pipeline, LLC*, 137 F.E.R.C. ¶ 61,098 at P 1 (2011).

471. *Id.* at PP 1-2.

472. *Id.* at P 2.

473. *Southern LNG Co.*, 137 F.E.R.C. ¶ 61,034 (2011).

capacity of its LNG import terminal on Elba Island, Georgia . . . in two phases.”⁴⁷⁴ In particular, one phase (Phase B) consisted “of an additional LNG storage tank and installation of submerged combustion vaporizers . . . to provide LNG terminalling service to BG LNG Services, LLV (BG),” with a precedent agreement in place for BG to receive the entire firm capacity.⁴⁷⁵ “BG [later] notified Southern LNG that it could not satisfy or waive one of the conditions precedent.”⁴⁷⁶ Thereafter, Southern LNG requested the FERC to vacate the portion of the FERC authorization related to constructing facilities associated with Phase B, which the FERC granted.⁴⁷⁷

In *Port Arthur LNG, L.P. and Port Arthur Pipeline, L.P.*, the FERC vacated Port Arthur LNG, L.P.’s (Port Arthur LNG) NGA section 3 authorization to site, construct, and operate an LNG terminal near Port Arthur, Texas, and vacated Port Arthur Pipeline, L.P.’s (Port Arthur Pipeline) section 7(c) authorization to construct associated pipelines from the LNG terminal’s outlet to interstate pipeline interconnections in Beauregard Parish, Louisiana and Jefferson County, Texas.⁴⁷⁸ Both companies planned to construct the facilities in two phases, and the FERC’s authorization required them to place the Phase I and Phase II facilities into service within three years and five years, respectively, of the date of the authorizations.⁴⁷⁹ The FERC vacated the authorizations since the already extended deadline had expired, and neither Port Arthur LNG nor Port Arthur Pipeline requested additional extensions.⁴⁸⁰

In *Creole Trail LNG, L.P.*, the FERC vacated Creole Trail LNG, L.P.’s (Creole Trail) section 3 authorization for an LNG terminal in Cameron Parish, Louisiana to receive foreign-sourced LNG, which “required the authorized facilities to be completed and placed into service within four years of the [authorization].”⁴⁸¹ The FERC vacated the section 3 authorization since Creole Trail did not construct and place the LNG terminal into service by the extended deadline.⁴⁸²

In *Ingleside Energy Center, LLC and San Patricio Pipeline, LLC*, the FERC vacated Ingleside Energy Center, LLC’s (Ingleside) section 3 authorization for an LNG terminal near Ingleside, Texas, and vacated its affiliate’s, San Patricio Pipeline, LLC (San Patricio), section 7(c) authorization for the associated pipeline to be constructed from the LNG terminal’s outlet to several interstate and intrastate pipeline interconnections in San Patricio County, Texas.⁴⁸³ The FERC required Ingleside and San Patricio to place the authorized facilities into service within three years of the date of authorization.⁴⁸⁴ The FERC vacated

474. *Id.* at P 2.

475. *Id.* at P 3.

476. *Id.* at P 4.

477. *Id.* at P 5.

478. *Port Arthur LNG, L.P. and Port Arthur Pipeline, L.P.*, 136 F.E.R.C. ¶ 61,196 at PP 1-2 (2011).

479. *Id.* at P 2.

480. *Id.*

481. *Creole Trail LNG, L.P.*, 136 F.E.R.C. ¶ 61,122 at P 1 (2011).

482. *Id.*

483. *Ingleside Energy Center, LLC and San Patricio Pipeline, LLC*, 136 F.E.R.C. ¶ 61,114 (2011).

484. *Id.* at P 2.

both authorizations since construction of the facilities had not commenced by the extended deadline.⁴⁸⁵

Since July of 2011, the Department of Energy Office of Fossil Energy (DOE-FE) has issued seven authorizations for the long-term export of LNG to any country with which the United States has, or in the future may enter into, a free trade agreement (FTA) requiring national treatment for trade in natural gas. The DOE-FE issued long-term FTA authorizations to: Lake Charles Exports, LLC;⁴⁸⁶ Carib Energy (USA) LLC;⁴⁸⁷ Dominion Cove Point LNG, LP;⁴⁸⁸ Jordan Cove Energy Project, L.P.;⁴⁸⁹ Cameron LNG, LLC;⁴⁹⁰ and LNG Development Company, LLC (d/b/a Oregon LNG).⁴⁹¹ To date, the export project of Sabine Pass Liquefaction, LLC and Sabine Pass LNG, LP is the only project authorized by the DOE to export domestically produced LNG to non-FTA countries.⁴⁹²

485. *Id.*

486. Order No. 2987, Lake Charles Exports, LLC, Docket No. FE11-59-LNG (DOE-FE July 22, 2011).

487. Order No. 2993, Carib Energy (USA) LLC, Docket No. FE11-71-LNG (DOE-FE July 27, 2011).

488. Order No. 3019, Dominion Cove Point LNG, LP, Docket No. FE11-115-LNG (DOE-FE Oct. 7, 2011).

489. Order No. 3041, Jordan Cove Energy Project, L.P., Docket No. FE11-147-LNG (DOE-FE Dec. 7, 2011).

490. Order No. 3059, Cameron LNG, LLC, Docket No. FE11-145-LNG (DOE-FE Jan. 17, 2012).

491. Order No. 3100, LNG Development Co., LLC, Docket No. FE12-48-LNG (DOE-FE May 31, 2012).

492. Order No. 2961, Sabine Pass Liquefaction, LLC, Docket No. FE10-111-LNG (DOE-FE May 20, 2011).

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