REPORT OF THE NATURAL GAS REGULATION COMMITTEE

This report summarizes policy developments and legal decisions that have occurred at the Federal Energy Regulatory Commission (Commission or the FERC) and the U.S. Courts of Appeals in the area of natural gas regulation. The time frame covered by this report is the period between July 1, 2010 and June 30, 2011.

I. RULEMAKING PROCEEDINGS

A. Affiliate Rules

On April 8, 2011, the FERC issued *Order No. 717-D* regarding the standards of conduct for transmission providers clarifying when employees who perform system impact studies will be considered transmission function employees or merchant function employees.[1]

On August 26, 2010, the FERC issued an order denying clarification and rehearing of *Order No. 2005-B*,[2] regarding the standards of conduct applicable in open seasons for capacity on an Alaska natural gas pipeline.[3] The State of Alaska asked for clarification that the Standards of Conduct "continue to apply after the . . . initial bidding period of an open season" and through the time that the pipeline commences "transportation service under the jurisdiction of the Natural Gas Act (NGA)."[4] The FERC rejected Alaska's request for clarification and noted that "the Standards of Conduct apply from the beginning of the open season until precedent agreements are executed."[5]

B. *Financial Forms*

On January 20, 2011, the FERC issued *Order No. 710-B*, revising the financial reporting requirements of interstate pipelines "to include functionalized fuel data . . . and to include . . . the amount of fuel [that is] waived, discounted or reduced as part of a negotiated rate agreement."[6] The FERC required that fuel use data "be reported on a monthly basis in the quarterly reports" in order to provide greater transparency.[7] The FERC found that separate reporting of "forwardhaul and backhaul volumes . . . would allow the Commission and customers" to evaluate whether fuel use "assigned to customers in their bills contain[s] . . . cross-subsidies, based on the inclusion of backhaul volumes in their gas purchases."[8] The FERC determined that the information required by the revised forms "may require some companies to revise accounting systems."[9] Pipeline companies "must begin collecting the more detailed [information beginning] on July 1, 2011, and must use that data in completing their FERC Form Nos. 2, 2-A and 3Q" filed after that date.[10]

C. *Market Transparency*

On June 17, 2010, the FERC issued *Order No. 704-C*, clarifying its newly created "Form No. 552, under which natural gas market participants must annually report information regarding physical natural gas transactions that use an index or that contribute to or may contribute to the formation of a gas [price]

1. Order No. 717-D, *Standards of Conduct for Transmission Providers*, 135 F.E.R.C. ¶ 61,017 (2011).
2. Order No. 2005-B, *Regulations Governing the Conduct of Open Seasons for Alaska Natural Gas Transportation Projects*, F.E.R.C. STATS. & REGS. ¶ 31,304, 75 Fed. Reg. 15,356 (2010) (to be codified at 18 C.F.R. pt 157).
3. *Regulations Governing the Conduct of Open Seasons for Alaska Natural Gas Transportation Projects*, 132 F.E.R.C. ¶ 61,175 (2010).
4. *Id.* at P 1.
5. *Id.* at P 19.
6. *Revisions to Forms, Statements, and Reporting Requirements for Natural Gas Pipelines*, 134 F.E.R.C. ¶ 61,033 at P 1 (2011).
7. *Id.* at P 7.
8. *Id.* at P 51.
9. *Id.* at P 78.
10. *Id.* at P 79.

index."[11] In addition to a number of minor clarifications, the FERC responded to market participant concerns by clarifying that certain unexercised options and cash-out and imbalance transactions are exempt from this reporting obligation. The order also clarified the scope of the exemption for unprocessed gas transactions and removed "the form's references to the blanket sales certificates issued under" 18 C.F.R. §§ 284.402 or 284.[12]

On July 21, 2010, the FERC issued *Order No. 720-B*, clarifying certain aspects of its reporting regulations "requiring major non-interstate pipelines to post daily scheduled volume information and other data for" each receipt or delivery point with a design capacity greater than 15,000 MMbtu per day, "as well as its regulations requiring interstate pipelines to post information regarding the provision of no-notice service."[13] The FERC order: clarified the scope of the major non-interstate pipeline designation, the procedures pipelines must follow when posting receipt/delivery points with unknown design capacities, and the timing deadline for posting new receipt/delivery points;[14] provided a compliance deadline of "150 days from the date the pipeline meets the definition of a major non-interstate pipeline or is no longer exempt to comply with the posting requirements;"[15] altered the posting requirements for delivery points dedicated to a single customer to address concerns regarding posting of customer-specific confidential information;[16] and amended its regulations to reflect that a pipeline must provide no-notice transportation information "based on its best estimate before 11:30 a.m. central clock time three days after the day of gas flow and make one update to each posted figure as necessary within ten business days after the month in which the posted service was performed."[17]

On December 16, 2010, the FERC issued *Order No. 735-A*, largely affirming its previous decision "to bring the less stringent transactional reporting requirements for section 311 and Hinshaw pipelines closer in line with the reporting requirements for interstate pipelines."[18] The new requirements increased the frequency of these facilities' reporting obligations from annually to quarterly, called for the reporting of new types of information, encompassed storage transactions, introduced a standardized electronic reporting format, and required that all reports be filed in a public (not privileged or redacted) format.[19]

On July 23, 2010, in *Arizona Public Service Co.*, the FERC denied a joint petition by Arizona Public Service Company (APS) and Sequent Energy

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11. Order No. 704-C, *Transparency Provisions of Section 23 of the Natural Gas Act*, F.E.R.C. STATS. & REGS. ¶ 31,312, 75 Fed. Reg. 35,632 (2010) (to be codified at 18 C.F.R. pt. 260).

12. *Id*.

13. Order No. 720-B, *Pipeline Posting Requirements Under Section 23 of the Natural Gas Act*, F.E.R.C. STATS. & REGS. ¶ 31,314, 75 Fed. Reg. 44,893, 44,893 (2010) (to be codified at C.F.R. pt. 284). A "major non-interstate pipeline" is defined as a natural gas pipeline that "is not a 'natural gas pipeline' under . . . the NGA . . . and delivers annually more than 50 million MMBtu of natural gas measured in average deliveries over the past three [calendar] years." *Id.* at P 12.

14. *Id.* at P 35.

15. *Id.*

16. *Id.* at P 42.

17. *Id*. at P 53.

18. Order No. 735-A, *Contract Reporting Requirements of Intrastate Natural Gas Companies*, F.E.R.C. STATS. & REGS. ¶ 31,318 at P 1, 75 Fed. Reg. 80,685 (2010) (to be codified at 18 C.F.R. pt. 284).

19. *Id.*

Management, L.P. (Sequent) for clarification that a proposed storage transaction involving rights on a Hinshaw storage facility in the Southwest would not constitute a violation of the agency's prohibition on buy-sell transactions.[20] Sequent (which held firm storage rights on a Hinshaw storage facility) and APS proposed a transaction in which Sequent would purchase APS's natural gas, store it using Sequent's storage rights, and then (upon request) sell the gas back to APS following withdrawal.[21] According to the petitioners, this transaction was necessary because the storage facility, like virtually all section 311 and Hinshaw facilities, did not have a capacity release mechanism in place to provide for capacity transfers between shippers. The FERC declined to grant the requested clarification and found, instead, that the transaction constituted a prohibited buy-sell arrangement. According to the FERC, even despite the absence of a capacity release mechanism, such a transaction would reduce transparency on the system.[22] The FERC concluded that granting "a blanket authorization for buy/sell transactions" like the one proposed "would allow holders of capacity on such pipelines to privately contract to allow another party to make use of their capacity without informing the pipeline or publicly disclosing the transaction."[23] However, the FERC recognized the commercial necessity and reliability benefits of the transaction and granted a limited waiver to allow the parties to consummate their transaction.[24]

In response to the gas industry's overwhelming response to the decision, the agency issued a Notice of Inquiry to examine two broad issues, namely, whether shippers using section 311 and Hinshaw facilities may enter into buy-sell transactions and, separately, whether such facilities should be required to adopt capacity release mechanisms.[25] Concurrently, the FERC issued its order denying rehearing in which it issued a temporary blanket waiver of buy-sell transactions on section 311 and Hinshaw facilities, pending the outcome of its rulemaking proceeding.[26]

II. RATES, TERMS, AND CONDITIONS OF SERVICE

A. *Abandonment*

In *Transcontinental Gas Pipe Line Co.*, the FERC approved the pipeline's application under section 7(b) of the Natural Gas Act to abandon case-specific (not open access) storage and related transportation services to Atlanta Gas Light Company (AGL) at the end of the contract terms.[27] The FERC stated that it "no longer presumes that service under case-specific Part 157 authority should continue after expiration of the service contracts," expressing concern that the shipper would otherwise be "receiving favorable treatment not available to other

20. *Arizona Public Service Co.*, 132 F.E.R.C. ¶ 61,064 at P 1 (2010).

21. *Id.* at P 4.

22. *Id.* at P 14.

23. *Id.* at P 18.

24. *Id.* at P 22.

25. Notice of Inquiry, *Capacity Transfers on Intrastate Natural Gas Pipelines*, F.E.R.C. STATS. & REGS. ¶ 35,567, 75 Fed. Reg. 66,046 (2010) (to be codified at 18 C.F.R. pt. 284).

26. *Arizona Public Service Co*., 133 F.E.R.C. ¶ 61,049 (2010).

27. *Transcontinental Gas Pipe Line Co.*, 134 F.E.R.C. ¶ 61,238 at P 1 (2011).

shippers."[28] The FERC held that it was incumbent upon AGL to demonstrate that it would not be reasonable to allow the requested abandonment and found that AGL had not met its burden because there were open access storage and transportation services available to satisfy AGL's needs for winter service.[29]

In *Northern Natural Gas Co.,* the FERC denied the request of several pipelines under section 7(b) of the Natural Gas Act to abandon their jointly-owned pipeline system in the Gulf of Mexico known as the Matagorda Offshore Pipeline System (MOPS).[30] The pipelines contended that it was no longer economic to operate MOPS as a result of declining production and lack of drilling in the offshore area accessible to MOPS, with MOPS' no longer having any firm transportation shippers and its throughput having declined to less than 35,000 Dth/day of its 480,000 Dth/day capacity.[31] The FERC expressed concern that the proposed abandonment could strand significant offshore production which had no economic delivery alternatives.[32] The FERC also dismissed the pipelines' concerns that operation of MOPS was becoming unsafe to operate because of the low throughput.[33] The FERC stated that the pipelines had the alternative of filing to increase MOPS rates under section 4 of the Natural Gas Act (NGA) and of re-filing for abandonment if the situation further deteriorated.[34]

In *El Paso Natural Gas Co.*, the FERC rejected an application by the pipeline under NGA section 7(c)(1)(B) to deactivate, for up to four years, nine idled compressor stations.[35] The FERC stated that, despite its past practice, going forward it will consider requests for deactivation of facilities under NGA section 7(b).[36] The FERC noted that the four-year request for deactivation was longer than the deactivation period approved in prior cases and the compressor units at issue were not inoperable.[37] It also noted that the pipeline had not demonstrated that its rates would be lowered as a result of the deactivation. The FERC explained that the reduction in system capacity due to the requested deactivation "would limit El Paso's ability to offer the same levels of firm services in the future, including hourly, peaking, and short term firm services."[38] In a footnote, the FERC stated that the pipeline is not obligated under its certificate authorization to operate the facilities and may maintain the compressors as backup or spare compression.[39]

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28. *Id*. at P 39.
29. *Id.* at P 43.
30. *Northern Natural Gas Co.*, 135 F.E.R.C. ¶ 61,048 at P 1 (2011).
31. *Id.* at P 4.
32. *Id.* at P 38.
33. *Id.* at P 39.
34. *Id.* at P 43.
35. *El Paso Natural Gas Co.*, 135 F.E.R.C. ¶ 61,079 at P 1 (2011).
36. *Id.* at P 17.
37. *Id.* at PP 23-26.
38. *Id.* at P 26.
39. *Id.* at P 26 n.29.

B. Ad Valorem *Taxes*

In *Northern Natural Gas Co.*, the FERC accepted and set for hearing a filing under NGA section 4 to recoup refunds paid to Burlington Resources Oil & Gas Company (Burlington) attributable to Kansas *ad valorem* tax reimbursements originally paid by Northern Natural Gas Co. (Northern) to Burlington under gas purchase agreements between 1983 and 1986.[40] The order represented the latest chapter in a litigation that has spanned nearly three decades involving issues under the ceiling prices established by Title I of the Natural Gas Policy Act of 1978, which was repealed more than two decades ago.[41] The issues set for hearing include whether Northern had previously agreed, in earlier settlements with its former sales customers or in settlement of contractual disputes with Burlington, to assume liability for Burlington's *ad valorem* tax refunds.[42]

C. Capacity Release

In *Gulf Crossing Pipeline Co.*, the FERC clarified a letter order accepting a permanent capacity release agreement containing a negotiated rate, stating "that a permanent release may qualify as a 'release to an asset manager'" as defined in section 284.8(h) of the FERC's regulations issued in the *Order No. 712* series.[43] The FERC clarified that either temporary or permanent releases can qualify as asset management agreements, which are exempted from the FERC's capacity release rules on posting and bidding and its prohibition on tying.[44]

In *Sempra Energy Trading LLC and J.P. Morgan Ventures Energy Corp.,* as in prior cases, the FERC granted, for 180 days, waivers of its capacity release and other rules as necessary to allow assignment and transfer of transportation, storage, and other service agreements to effect the merger or sale of entire business units.[45] The FERC waived its rules regarding the posting and bidding requirements and the limits on the rates that can be accepted in capacity release transactions, "the shipper-must-have-title policy, the prohibitions on buy/sell arrangements," the prohibition against tying, and various pipeline tariff requirements.[46]

In an unpublished *Staff Report on Capacity Release* covering the period 2008-2010, the FERC staff reported that "[t]here has been no discernible positive or adverse impact on the capacity release market from Order No. 712."[47]

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40. *Northern Natural Gas Co.*, 134 F.E.R.C. ¶ 61,218 at PP 1-2 (2011) [hereinafter *Northern Natural 2011 Order*].

41. 15 U.S.C. §§ 3301-3320 (repealed eff. Jan. 1, 1993).

42. *Northern Natural 2011 Order*, *supra* note 40, at P 28.

43. *Gulf Crossing Pipeline Co.*, 132 F.E.R.C. ¶ 61,026 at P 4 (2010); Order No. 712, *Promotion of a More Efficient Capacity Release Market*, F.E.R.C. STATS. & REGS. ¶ 31,271, 73 Fed. Reg. 37,058 (2008), *order on reh'g,* Order No. 712-A, F.E.R.C. STATS. & REGS. ¶ 31,284, 73 Fed. Reg. 72,692 (2008), *order on reh'g and clarification*, Order No. 712-B, 127 F.E.R.C. ¶ 61,051, 74 Fed. Reg. 18,127 (2009).

44. 132 F.E.R.C. ¶ 61,026 at P 3.

45. *Sempra Energy Trading LLC,*133 F.E.R.C. ¶ 61,128 at PP 1, 22 (2010).

46. *Id*. at P 21.

47. Staff Report on Capacity Release at 8, FERC Docket No. RM08-1-000 (Jan. 31, 2011).

Among other findings, the FERC staff concluded that "[r]emoval of the price cap [on releases of one year or less] has not had a significant impact on pricing."[48]

D. Creditworthiness

In *Kern River Gas Transmission Co.*, the FERC rejected the pipeline's proposal to remove language from its tariff permitting a shipper's creditworthiness to be established by Kern River's numerous lenders.[49] Kern River's proposal to remove the language was based on its assertion that the lender approval provision was unworkable and that its lenders would not overrule management's business judgment on a shipper's creditworthiness.[50] The FERC reasoned that the pipeline, having used its lending agreements to obtain more collateral and, "[h]aving based its higher collateral requirement on [the needs'] of its lenders, . . . failed to show that it would be just and reasonable" to eliminate shipper access to lenders for purposes of seeking a reprieve from the higher collateral requirements.[51]

In *Texas Gas Transmission, LLC*, the FERC approved revisions to the creditworthiness provisions in the FERC Gas Tariff of Texas Gas Transmission, LLC (Texas Gas).[52] Texas Gas had proposed that to be creditworthy, a shipper must have investment grade credit rating for unsecured debt or a borderline rating with a stable or positive outlook, and "the net present value of the sum" of the shipper's reservation charges and other fees must be "less than five percent of the customer's tangible net worth."[53] Alternative methods of establishing creditworthiness were proposed.[54] Regarding collateral requirements, Texas Gas sought to require security for imbalance gas.[55] Texas Gas' proposal also included provisions regarding calculation of security for park and loan customers.[56] Finally, Texas Gas sought approval of provisions that allowed it "to consider credit status . . . when allocating available capacity" and to adjust the net present value of a non-creditworthy bidders bid to reflect risk of default.[57] After protests were filed, Texas Gas submitted clarified provisions, and the FERC approved the revised proposal, effective May 15, 2011, subject to Texas Gas submitting revised tariff records in accord with the FERC's order.[58]

E. Discount Adjustments for Negotiated Rate Agreements

In *Columbia Gulf Transmission Co.*,[59] the FERC approved tariff revisions that allow the pipeline to file for a discount-type adjustment for its negotiated rate agreements consistent with the FERC's earlier decision in *Wyoming*

48. *Id*.
49. *Kern River Gas Transmission Co.*, 132 F.E.R.C. ¶ 61,080 at P 1 (2010).
50. *Id.* at P 8.
51. *Id*. at P 23.
52. *Texas Gas Transmission, LLC*, 135 F.E.R.C. ¶ 61,132 at P 1 (2011).
53. *Id.* at P 3.
54. *Id.*
55. *Id.* at P 5.
56. *Id.*
57. *Id.* at P 7.
58. *Id.* at PP 3, 35, 37.
59. *Colombia Gulf Transmission Co.*, 133 F.E.R.C. ¶ 61,078 (2010).

Interstate Company, Ltd.[60] The FERC approved similar tariff revisions in *Kinder Morgan Interstate Gas Transmission, LLC.*[61]

In *Tennessee Gas Pipeline Co.,* the FERC issued an order discussing its policies regarding discount-type adjustments for negotiated rate agreements.[62] The FERC explained that pipelines have long been "permitted to offer discounts . . . on a non-discriminatory basis, in order to meet competition."[63] In reviewing proposed discount adjustments, the FERC stated that "pipeline[s] ha[ve] a heavy burden to show that competition required discounts to affiliates" and must "identif[y] the specific competitive alternatives the affiliate had, which required giving the discount."[64] The FERC stated that, in *Wyoming Interstate*, "although it was not promulgating a *per se* rule against discount-type adjustments to recourse rates to reflect negotiated rates, [it] required that a pipeline's negotiated rate proposal protect the recourse . . . shippers against inappropriate cost-shifting."[65] The FERC emphasized that in both *Wyoming Interstate* and *Columbia Gulf*, "the tariff language adequately protected recourse rate shippers by requiring the pipelines to[: (1)]satisfy the same heavy burden pipelines must bear with respect to affiliate discounts to show that competition required the discount[; and (2)] demonstrate that any discount-type adjustment 'does not have an adverse impact on recourse rate shippers.'"[66] The FERC added that those orders "also pointed out that," in a section 4 rate case, "shippers will have the opportunity to fully evaluate all of the pipeline's" costs and revenues and to "raise the issue [of] whether any proposed . . . adjustment is consistent with the policy that 'pipelines should not be able to shift the cost of below maximum rate discounts to the recourse rate shippers, while keeping the profits from above maximum rate [agreements].'"[67]

The FERC held that "if a pipeline chooses not to include in its tariff a provision permitting a discount adjustment for negotiated rates, 'there is no requirement for the pipeline to flow-through to recourse rate shippers any revenue the pipeline receives'" from negotiated rates in excess of the maximum rate.[68] However,

> if the pipeline [does] include[] in its tariff a provision permitting discount adjustments for negotiated rates . . . , [the] pipeline may obtain a discount adjustment . . . [only] if it satisfies the burden of proving that the negotiated rates were required to meet competition and that the adjustment does not have an adverse impact on recourse . . . shippers.[69]

In particular, the FERC stated that "if during the test period in a section 4 rate case, the rates for some negotiated rate transactions were in excess of the maximum recourse rate, the volumes associated with those transactions may be

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60. *Wyoming Interstate Co.*, 117 F.E.R.C. ¶ 61,150 (2006).
61. Letter Order Pursuant to 18 C.F.R. § 375.307, FERC Docket No. RP11-1542-000 (Dec. 15, 2010).
62. *Tennessee Gas Pipeline Co.*, 135 F.E.R.C. ¶ 61,208 (2011).
63. *Id.* at P 186.
64. *Id.* at P 190.
65. *Id.* at P 196.
66. *Id.* at P 197.
67. *Id.*
68. *Id.* at P 203.
69. *Id.* at P 204.

adjusted upward to allocate costs to those transactions based on the actual revenues received."[70] The FERC concluded that these procedures "provide[] a reasonable framework for considering in a general section 4 rate case whether to permit a discount adjustment for a pipeline's negotiated rate transactions."[71] Subsequently, the FERC approved similar tariff revisions permitting the pipeline to file for discount-type adjustments for negotiated rate agreements in *Transwestern Pipeline Co.*[72] and *Gulf South Pipeline Co.*[73]

F. Exports

1. FERC Orders Granting Authority to Export Natural Gas

On September 16, 2010, the FERC issued orders amending the Presidential Permits and NGA section 3 authorizations of two interstate pipelines, *Empire Pipeline, Inc*.[74] and *Iroquois Gas Transmission System, L.P.*[75] The orders grant each pipeline authority to utilize their existing cross-border facilities to export, as well as import, natural gas between the United States and Canada.[76] Similarly, on March 7, 2011, the FERC issued an order amending the Presidential Permit and NGA section 3 authorization of *Tennessee Gas Pipeline Co.* to allow Tennessee to use its current facilities to export natural gas into Canada.[77]

The FERC granted the applicants' requests for authority to use their facilities to export, as well as import, natural gas upon finding that such activity would be consistent with the public interest.[78] In this regard, the FERC noted that Canada is a signatory of the North American Free Trade Agreement (NAFTA)[79] and that

> NGA section 3 provides that the importation or exportation of natural gas from/to a "nation with which there is a free trade agreement requiring national treatment for trade in natural gas, shall be deemed to be consistent with the public interest, and applications for such importation and exportation shall be granted without modification or delay."[80]

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70. *Id.*

71. *Id.* at P 208.

72. *Transwestern Pipeline Co.*, 135 F.E.R.C. ¶ 61,220 (2011).

73. *Gulf S. Pipeline Co.*, 136 F.E.R.C. ¶ 61,029 (2011). Similar tariff revisions were filed by the three pipelines owned by Boardwalk Pipeline Partners – Gulf South Pipeline Company, Gulf Crossing Pipeline Company, and Texas Gas Transmission. The FERC had originally suspended the tariff filings pending a further order discussing the FERC's policy on discount-type adjustments for negotiated rate agreements. *Gulf S. Pipeline Co.*, 135 F.E.R.C. ¶ 61,129 (2011). As noted, the FERC explained its policy in *Tennessee Gas Pipeline Co.*, 135 F.E.R.C. ¶ 61,208 (2011).

74. *Empire Pipeline, Inc.*, 132 F.E.R.C. ¶ 61,229 (2010).

75. *Iroquois Gas Transmission Sys., L.P.*, 132 F.E.R.C. ¶ 61,230 (2010).

76. *Id.* at P 10.

77. *Tennessee Gas Pipeline Co.*, 134 F.E.R.C. ¶ 61,175 at P 1(2011).

78. *Id.*

79. North American Free Trade Agreement Implementation Act, Pub. L. No. 103-182, 107 Stat. 2057 (1993); Implementation of the North American Free Trade Agreement Act, Exec. Order No. 12,889, 58 Fed. Reg. 69,681 (Dec. 30, 1993), *available at* http://www.archives.gov/federal-register/executive-orders/pdf/12889.pdf.

80. 134 F.E.R.C. ¶ 61,175 at P 7 (quoting 15 U.S.C. § 717b(c) (2006)).

2. DOE/FE Orders Granting Authority to Export LNG

On September 7, 2010, the U.S. Department of Energy, Office of Fossil Energy (DOE/FE)[81] issued Order No. 2833, granting an application filed by Sabine Pass Liquefaction, LLC (Sabine Pass), a subsidiary of Cheniere Energy, Inc., for authorization to export up to 803 Bcf per year of domestically produced liquefied natural gas (LNG) for a term of thirty years from the Sabine Pass LNG Terminal, an affiliate-owned, "existing LNG import facility in Cameron Parish, Louisiana," to countries with which the United States has a Free Trade Agreement (FTA).[82] Thereafter, Sabine Pass sought and was granted long-term authorization from DOE/FE to export domestically produced LNG for a term of twenty years from the Sabine Pass LNG Terminal to countries with which the United States does not have an FTA.[83]

The DOE/FE authorizations sought by Sabine Pass relate to its "development of the Sabine Pass Liquefaction Project," a project pending review by the FERC that would involve construction of new facilities to liquefy domestically-produced natural gas for storage at the Sabine Pass LNG Terminal and export via LNG tankers to foreign destinations.[84] Sabine Pass indicated that it would export LNG on its own behalf or as agent for others and that it might or might not hold title to the gas at time of export.[85] It also sought a waiver of the DOE/FE filing requirements regarding source and supply of the natural gas to be exported.[86]

Sabine Pass contended in its application that the exportation of LNG is consistent with the public interest in that natural gas supplies in the U.S. are abundant and increasing opportunities for export would stimulate domestic production, help moderate price volatility, and yield job creation and other economic development benefits to the State of Louisiana, Gulf Coast, and U.S. in general.[87] Sabine Pass included with its application three reports which address the scope of domestic natural gas resources, "potential increase in petroleum liquids production" resulting from the Sabine Pass Project, and the impact the exportation of natural gas would have on natural gas prices.[88]

The "DOE/FE received seven letters in support of" Sabine Pass's application and two oppositions.[89] The Industrial Consumers of America (IECA) and the American Public Gas Association (APGA) argued that exports

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81. 15 U.S.C. § 717b. This authority was delegated to the Assistant Secretary for Fossil Energy pursuant to Redelegation Order No. 00-002.04D. DOE, REDELEGATION ORDER NO. 00-002.04D (Nov. 6, 2007) (rescinded by Redelegation Order No. 00-002-04E as of May 2, 2011).

82. *Sabine Pass Liquefaction, LLC* at 2, DOE/FE Order No. 2833 (Sept. 7, 2010), *available at* http://www.fossil.energy.gov/programs/gasregulations/authorizations/Orders_Issued_2010/ord28332.pdf. Currently the United States has FTAs requiring national treatment for trade in natural gas and LNG with the following countries: Australia, Bahrain, Singapore, Dominican Republic, El Salvador, Guatemala, Honduras, Nicaragua, Chile, Morocco, Canada, Mexico, Oman, Peru, and Jordan. *Id.* at 2 n.2.

83. *Sabine Pass Liquefaction, LLC*, DOE/FE Order No. 2961 (May 20, 2011), *available at* http://www.cheniereenergypartners.com/lng_documents/DOE_order_approval.pdf.

84. *Id.* at 3.

85. *Id.* at 4.

86. *Id*.

87. *Id.* at 5-6.

88. *Id.* at 7.

89. *Id.* at 1.

of natural gas would drive up domestic prices and have a negative effect on the U.S. economy, as well as weaken U.S. energy security and frustrate the goal of U.S. energy independence.[90]

On May 20, 2011, the DOE/FE issued Order No. 2961, which conditionally granted Sabine Pass its requested long-term authorization to export liquefied natural gas (LNG) to non-free trade agreement nations for a twenty year period and at the annual volume levels requested.[91] The authorization was made conditional "on the satisfactory completion" by the FERC of its environmental review in the pending Sabine Pass NGA section 3 liquefaction facilities authorization proceeding.[92] Sabine Pass's request for waiver of source and security information reporting requirements was deemed unnecessary, given the DOE/FE's determination that the information was only required "to the extent" applicable or practicable and that Sabine Pass had adequately explained why such information in its case was neither.[93] The order imposes various other conditions on Sabine Pass including a requirement to commence export activity within seven years, to submit period reports, and to register with DOE/FE any entity for which Sabine Pass will be acting as agent in making exports of LNG.[94]

G. Fuel

In *Columbia Gulf Transmission Co*., the FERC accepted, subject to substantial modification, Columbia Gulf's proposal to implement a revised Incentive Fixed Fuel mechanism.[95] Under the proposal, Columbia Gulf would "recover[] its system fuel requirements . . . and lost and unaccounted for gas" through a fixed fuel retention rate, providing it with an incentive to perform system improvements and earn the difference between the fixed fuel rate and its actual fuel costs.[96] The FERC found "that Columbia Gulf's proposed" fixed fuel rates did not "reflect 'significant upfront savings' below Columbia Gulf's . . . cost-based rates."[97] In determining the amount of savings, the FERC held that fixed fuel rates should not be compared to cost-based rates that include surcharge amounts.[98] The FERC also found that fixed fuel rates could not be established absent actual data.[99] With respect to revenues from sales of retained fuel, the FERC rejected Columbia Gulf's proposed sharing mechanism and required a 67/33 allocation between Columbia Gulf and its customers.[100]

In a subsequent order, the FERC accepted Columbia Gulf's July 16, 2010 filing to remove its Incentive Fixed Fuel mechanism and replace it with its previously-approved Transportation Retainage Adjustment mechanism.[101]

90. *Id.* at 18-23.
91. *Id.* at 42.
92. *Id*. at 41.
93. *Id*.
94. *Id*. at 42-47.
95. *Columbia Gulf Transmission Co.*, 132 F.E.R.C. ¶ 61,009 (2010).
96. *Id.* at P 2.
97. *Id*. at P 41.
98. *Id*. at P 29.
99. *Id*. at P 36.
100. *Id*. at P 55.
101. *Columbia Gulf Transmission Co.*, 132 F.E.R.C. ¶ 61,134 at P 2 (2010).

Columbia Gulf indicated that it was unable to move forward with its Incentive Fixed Fuel as modified by the FERC.[102] The FERC accepted Columbia Gulf's proposal and found that requests for rehearing regarding Columbia Gulf's Incentive Fixed Fuel mechanism were moot.[103] The FERC also found that requests for rehearing that related to the general policy statement on incentive rates "do not lie" because policy statements do not constitute final agency action.[104]

Thereafter, in *Columbia Gulf Transmission Co.*,[105] the FERC denied rehearing and affirmed Columbia Gulf's 2009 retention percentages for fuel use and lost-and-unaccounted for gas, holding that Columbia Gulf was not required by its tariff to replace certain orifice meters with ultrasonic meters.[106] The FERC interpreted Columbia Gulf's tariff to require it to repair and adjust its orifice meters to comply with industry standards.[107] In other words, "orifice meters are not faulty meters that must be replaced."[108] The FERC concluded that the increased lost-and-unaccounted-for gas volumes "were not the result of any defect in the orifice meters" but were caused by, among other things, the fact that "orifice and ultrasonic meters are two different measuring technologies."[109] The FERC stated that Columbia Gulf has the discretion to "determine when and how to invest in the necessary metering upgrades" to its delivery stations.[110]

In *Portland Natural Gas Transmission System*, the FERC declined to allocate fuel requirements of Maritimes & Northeast Pipeline, L.L.C. (Maritimes) to Portland Natural Gas Transmission System (Portland) – two separate "pipeline systems that join together . . . in the form of a Y from which point they each own undivided interests in jointly-owned pipeline facilities (Joint Facilities)."[111] Maritimes proposed to construct two compressor stations on the Joint Facilities as part of the Phase IV Expansion Project.[112] Portland initially sought to collect in-kind fuel charges associated with Maritime's new compressor stations, but the FERC rejected that filing, determining that Maritime could not charge Portland or its shippers for fuel associated with Maritime's expansion.[113]

On rehearing, Maritimes argued that Portland's customers receive significant benefits from the expansion and that it was entitled to charge Portland for fuel under their various operating agreements.[114] The FERC denied Maritimes request for rehearing for three reasons. First, the agreements between

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102. *Id*. at P 24.

103. *Id*. at P 39.

104. *Id*. at P 45 (citing *Natural Gas Pipeline Negotiated Rates Policies and Practices*, 114 F.E.R.C. ¶ 61,042 at P 6 (2006); Pac. Gas & Elec. Co. v. FPC, 506 F.2d 33, 38 (D.C. Cir. 1974); and *Alternatives to Traditional Cost-of-Service Ratemaking for Natural Gas Pipelines*, 75 F.E.R.C. ¶ 61,024, at p. 61,076 (1996)).

105. *Columbia Gulf Transmission Co.*, 133 F.E.R.C. ¶ 61,027 (2010).

106. *Id.* at P 23.

107. *Id.*

108. *Id.* at P 24.

109. *Id*. at P 26.

110. *Id.* at P 27.

111. *Portland Natural Gas Transmission Sys.*, 132 F.E.R.C. ¶ 61,033 at P 2 (2010).

112. *Id.* at P 4.

113. *Id.* at P 10.

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

Maritimes and Portland do not allow Maritimes to allocate fuel requirements to Portland as the result of the Phase IV Expansion Project.[115] Second, no extrinsic evidence exists to demonstrate an intent or course of conduct supporting the sharing of fuel costs on the Joint Facilities.[116] Third, forcing Portland to pay for Maritimes' compressor fuel for Maritimes' Phase IV Expansion Project when Portland's shippers do not and cannot utilize that capacity would violate the FERC policy that "pipelines proposing new expansion projects must be prepared to financially support such projects without relying on subsidization from existing customers."[117] Because Portland's customers neither need the compressors to transport their gas on the joint facilities nor receive any operational benefits from the compressors, they cannot be allocated any of Maritime's fuel costs.[118]

In *Cheyenne Plains Gas Pipeline Co.*, the FERC clarified a prior letter order requiring "Cheyenne Plains to remove . . . costs associated with a fire at [a compressor station] from the calculation of its fuel and lost and unaccounted-for gas [(FL&U)] reimbursement percentages."[119] The FERC determined that even if the loss did not result from imprudent operations, "'lost and unaccounted-for gas' [does not] include all . . . losses except those attributable to imprudence or negligence,"[120] and that "a fuel tracking mechanism [is] not appropriate for the recovery of gas losses that are outside the scope of normal pipeline operations."[121] The FERC, however, clarified that "because Cheyenne Plains cannot recover the costs of the gas lost" as a result of the fire, it also does not have to include any insurance proceeds related to the incident in its FL&U reimbursement percentages.[122]

In *Rockies Express Pipeline LLC*, the pipeline filed two alternative sets of "revised tariff records to update its fuel lost and unaccounted for (FL&U) percentages."[123] "Option A allow[ed] REX to recover . . . quantities related to reduced fuel recovery resulting from a negotiated rate agreement with Encana Marketing,"[124] while "Option B [did] not adjust the rate percentages of other shippers to recoup the shortfall resulting from Encana's negotiated rate contract."[125] The FERC rejected Option A because REX's tariff stated that the Transporter (REX) bears the risk of any under-recovery resulting from negotiated rate agreements, and thus, their attempt to shift the costs to other shippers was contrary to their own tariff and Commission policy.[126] The FERC accepted and nominally suspended Option B, subject to further review, instructing REX to address "concerns regarding REX's . . . five-year

115. *Id.* at PP 60-61.
116. *Id.* at P 62.
117. *Id.* at PP 40, 54, 55.
118. *Id.* at PP 56-58.
119. *Cheyenne Plains Gas Pipeline Co.*, 132 F.E.R.C. ¶ 61,206 at P 1 (2010).
120. *Id.* at P 11.
121. *Id.* at P 12.
122. *Id.* at P 18.
123. *Rockies Express Pipeline LLC*, 134 F.E.R.C. ¶ 61,248 (2011).
124. *Id.* at P 3.
125. *Id.* at P 4.
126. *Id.* at PP 11-13.

amortization of fuel costs, the volumes used to calculate the FL&U rates, and the electricity costs incorporated into the FL&U rates."[127] The FERC also instructed REX to provide "a detailed accounting showing that no costs associated with any negotiated fuel rate" was shifted to the FL&U costs and borne by the other shippers.[128]

In *Trailblazer Pipeline Co.*, the FERC rejected Trailblazer's proposal to reflect its annual Expansion Fuel Adjustment Percentage "based upon the most recent four year average . . . , rather than base period data as defined" in its tariff because Trailblazer failed to show that the assumptions underlying its proposed four-year average were likely to reflect actual volumes.[129] The FERC also rejected a requested waiver that would allow Trailblazer to "exclude collections pursuant to the deferred rates,"[130] finding that deviation from the tariff could result in customers paying for the continued accumulation of money in Trailblazer's deferred account.[131]

Subsequently, the FERC rejected a compliance filing by Trailblazer that would have increased the Expansion Fuel Adjustment Percentage rate to 8.14%, reflecting base period data consistent with the tariff.[132] The FERC found that its prior order did not direct a compliance filing but simply rejected Trailblazer's proposed revisions.[133] Because FERC's regulations[134] prohibit the combination of compliance filings with other rate or tariff change filings, the FERC rejected Trailblazer's filing as an improper submission and required Trailblazer to make any new filing pursuant to NGA section 4 and the fuel tracker mechanism in Trailblazer's tariff.[135]

H. Gas Quality & Interchangeability

In *Florida Gas Transmission Co.*,[136] the FERC approved an uncontested settlement on certain gas quality issues in response to the U.S. Court of Appeals for the District of Columbia Circuit's opinion in *Florida Gas Transmission Co. v. FERC*.[137] The court's order had vacated the Commission's decision in *Opinion No. 495*[138] that gas from the Western Division of the Florida Gas system must satisfy the Market Area gas quality standards when entering Florida Gas' Market Area.[139] The Settlement requires Florida Gas to remove both its proposed tariff provision allowing Florida Gas to post gas quality standards for "gas flowing from the Western Division into the Market Area" and "the tariff

127. *Id.* at P 20.

128. *Id.*

129. *Trailblazer Pipeline Co.*, 135 F.E.R.C. ¶ 61,091 at PP 3, 10 (2011).

130. *Id.* at P 4.

131. *Id*. at P 10.

132. *Trailblazer Pipeline Co.*, 135 F.E.R.C. ¶ 61,161 at P 4 (2011).

133. *Id.*

134. 18 C.F.R. § 154.203(b) (2011).

135. 135 F.E.R.C. ¶ 61,161 at PP 3-5.

136. *Florida Gas Transmission Co.*, 132 F.E.R.C. ¶ 61,074 (2010).

137. Florida Gas Transmission Co. v. FERC, 604 F.3d 636 (D.C. Cir. 2010).

138. Opinion No. 495, *AES Ocean Express LLC v. Florida Gas Transmission Co.*, 119 F.E.R.C. ¶ 61,075 (2007), *order on reh'g*, Opinion No. 495-A, 121 F.E.R.C. ¶ 61,267 (2007), *order on reh'g*, Opinion No. 495-B, 125 F.E.R.C. ¶ 61,137 (2008).

139. *Florida Gas Transmission Co.*, 604 F.3d at 643.

provision requiring gas entering the Market Area from the Western Division to satisfy the Market Area gas quality standards."[140] "The Settlement also requires [the parties] to withdraw . . . request[s] for rehearing filed in the . . . proceeding [on] Florida Gas' gas quality standards."[141]

In *Southern LNG Co.*, the FERC approved with certain modifications an uncontested settlement agreement that revised Southern LNG's tariff.[142] The revisions established "a maximum Wobbe number limit" and "a maximum gross heating value" which in turn are subject to a formula limit, as well as limits on nitrogen, oxygen, and carbon dioxide.[143] No party may request removal of the formula limits unless certain conditions precedent are satisfied via a protocol to be followed by South Carolina Electric & Gas Company (SCE&G).[144] SCE&G must: (i) do an appliance performance analysis, which includes testing of appliances from SCE&G's system to measure the impacts to such appliances after operating using a variety of gas specified compositions; and (ii) "identify safety-related or appliance performance incidents on its system" for gas within a designated composition range.[145] The settlement sets out procedures and related obligations to be followed by Southern LNG and SCE&G to provide specified data and notices to each other in order to satisfy the second condition precedent.[146]

In *Texas Eastern Transmission, LP*, the FERC approved an uncontested settlement that revised the gas quality and interchangeability standards on the Texas Eastern system.[147] The settlement established a Control Zone extending from Berne, Ohio, to Uniontown, Pennsylvania, in which Texas Eastern is permitted to require that new "or significantly modified receipt points" have gas chromatographs or use the measurement methodology in Texas Eastern's tariff.[148] Similarly, "all new or significantly modified receipt points in the []East Texas Exemption Area," the portion of the system between Joaquin and Blessing, Texas, are required to have gas chromatographs or use the measurement methodology in the tariff.[149] Texas Eastern will post hourly average chromatograph data from certain mainline points and update its Informational Postings website with information from the mainline chromatographs.[150] The settlement included agreements between Texas Eastern and Dominion Transmission, Inc. (DTI), covering the jointly owned Oakford Storage Complex, and between Texas Eastern, DTI, and Transcontinental Gas Pipe Line Company, LLC, covering the jointly owned Leidy storage facilities.[151]

140. 132 F.E.R.C. ¶ 61,074 at P 7.

141. *Id.* The exception to this requirement is the rehearing request of Florida Power & Light Company (FPL) on cricondentherm hydrocarbon dew point. Although it was not required to be withdrawn, on April 22, 2011, FPL withdrew its request.

142. *Sourthern LNG Co.*, 135 F.E.R.C. ¶ 61,153 at P 1 (2011).

143. *Id.* at P 6.

144. *Id.*

145. *Id.* at P 7.

146. *Id.* at PP 8-9.

147. *Texas Eastern Transmission,* LP, 133 F.E.R.C. ¶ 61,114 at P 2 (2010).

148. *Id.* at P 7.

149. *Id.* at P 9.

150. *Id.* at P 10.

151. *Id.* at P 13.

"[T]he parties agree[d] not to seek termination or modification" of certain provisions of Texas Eastern's tariff covering heavier hydrocarbons "before October 1, 2014, absent a material change in circumstances or a change in Texas Eastern's obligations downstream of Uniontown."[152] The tariff revisions also included the conditions and procedures under which Texas Eastern or interested parties may initiate settlement discussions regarding the need for changes to certain provisions covering heavier hydrocarbons certain events occur prior to April 1, 2015.[153]

In *Columbia Gulf Transmission Co.*, the FERC denied rehearing and affirmed its prior rejection of tariff revisions that would have allowed Columbia Gulf to waive its gas quality standards, concluding that because Columbia Gulf's tariff does not have delivery point quality standards, Columbia Gulf may not waive its gas quality standards if doing so would result in deliveries at interconnections that would not meet receipt point specifications.[154] The FERC explained that absent any delivery point "gas quality and interchangeability standards or a merchantability" provision, Columbia Gulf's proposal would give it too much discretion to waive its gas quality standards "without any clear enforceable provision to which injured customers can resort."[155] The FERC added that there was insufficient evidence in the record from which the FERC "could develop a just and reasonable waiver alternative," and thus, rejection of the tariff proposal was appropriate.[156]

In *Tennessee Gas Pipeline Co.*, the FERC accepted and suspended revised gas quality and interchangeability tariff standards filed by Tennessee "subject to the outcome of . . . evidentiary hearing procedures."[157] The evidentiary proceedings were in turn held in abeyance pending discussions among the parties to be convened by a settlement judge.[158]

I. Leases

In *Midcontinent Express Pipeline LLC*, the FERC issued an order on remand of the U.S. Court of Appeals for the District of Columbia Circuit's decision in *Apache Corp. v. FERC*,[159] clarifying FERC policy on pipeline capacity leases.[160] The court had remanded for further explanation of whether Enogex's lease of pipeline capacity to Midcontinent Express Pipeline LLC (Midcontinent) met the FERC's standard for approval of such leases.[161] On remand, the FERC stated that its practice has been to approve a lease "if it finds that: (1) there are benefits from using a leasing arrangement; (2) the lease payments are less than, or equal to, the lessor's firm transportation rates for comparable service over the term of the lease; and (3) the lease arrangement

152. *Id.* at P 18.
153. *Id.*
154. *Columbia Gulf Transmission Co.*, 134 F.E.R.C. ¶ 61,194 at P 1 (2011).
155. *Id*. at P 18.
156. *Id*. at P 21.
157. *Tennessee Gas Pipeline Co.*, 135 F.E.R.C. ¶ 61,098 at P 1 (2011).
158. *Id.* at P 33.
159. Apache Corp. v. FERC, 627 F.3d 1220 (D.C. Cir. 2010).
160. *Midcontinent Express Pipeline LLC*, 134 F.E.R.C. ¶ 61,155 at P 1 (2011).
161. *Id.*

does not adversely affect existing customers."[162] The FERC explained that the third prong is not an absolute test to be applied in a vacuum. Rather, the FERC stated that it will consider whether the adverse "impact would outweigh the positive benefits."[163] The FERC further explained that Apache has only a "contingent" or interruptible right to use capacity, which is not an adverse effect of the type that is avoidable.[164] "[I]f the 'no adverse effects' provision . . . is taken as an absolute, the Commission could not approve leases of capacity by any pipeline with existing interruptible shippers."[165]

J. Market-Based Rates

In a series of orders involving Northern Natural Gas Co. (Northern), the FERC clarified the scope and requirements of authorizations for market-based rates under NGA section 4(f). Northern had requested and received authority to charge market-based rates for certain new storage capacity at its Redfield Storage facility, by means of a declaratory order issued in 2006[166] under Order No. 678,[167] which implemented NGA section 4(f).[168]

On June 11, 2010, Northern filed tariff sheets proposing provisions to govern resale of the expansion capacity authorized in the 2006 Order, which would be offered at market-based rates under provisions addressing the consumer protection requirements of NGA section 4(f).[169] In July of 2010, the FERC set the proposal for technical conference,[170] and on December 10, 2010, the FERC issued an order rejecting the tariff filing.[171] The FERC *sua sponte* raised a "threshold issue": whether Northern was proposing market-based rates for service beyond the scope of the original authorization in the 2006 Order.[172] The FERC concluded that the 2006 Order only authorized market-based rates for the precedent agreements signed for service during the initial open season for the new service using the expanded facilities and did not apply to contracts for the resale of capacity authorized in the 2006 Order.[173] The FERC found that Northern could not make the statutory showing under NGA section 4(f) because

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162. *Id.* at P 4 (citing *Gulf Crossing Pipeline Co.*, 123 F.E.R.C. ¶ 61,100 at P 111 (2008) (citing *Texas Gas Transmission, LLC*, 113 F.E.R.C. ¶ 61,185 at P 10 (2005); *Islander East*, 100 F.E.R.C. ¶ 61,276 at P 69 (2002))).

163. *Id.* at P 13 ("[W]e will not consider any of the prongs of the test in isolation, but rather will balance them, on a case-by-case basis. Given the facts of individual lease cases, we will determine whether a proposal meets all of the three established criteria, and, if it does not, weigh the significance of the lease's failure to satisfy any criterion against the benefits it would provide with respect to other criteria.").

164. *Id.* at P 15.

165. *Id.* at P 16.

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

167. Order No. 678, *Rate Regulation of Certain Natural Gas Storage Facilities*, F.E.R.C. STATS. & REGS. ¶ 31,220, 71 Fed. Reg. 36,612 (2006).

168. NGA Section 4(f) was enacted in the Energy Policy Act of 2005. Pub. L. No. 109-58, § 312, 119 Stat. 594, 688 (2005) (codified at 15 U.S.C. § 717c(f)(1)(A)) (§ 4(f)).

169. *Northern Natural Gas Co*., 132 F.E.R.C. ¶ 61,021 at PP 1-3 (2010).

170. *Id.* at P 1.

171. *Northern Natural Gas Co.*, 133 F.E.R.C. ¶ 61,210 (2010).

172. *Id*. at P 9.

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

that section requires construction of new facilities.[174] The FERC also found that in the event of default or turnback by a shipper during the initial twenty-year terms of the original contracts, Northern could remarket using the original market-based rate as a maximum rate subject to a reserve price at the just and reasonable tariff maximum rate, but it rejected tariff provisions containing generic remarketing provisions for NGA section 4(f) capacity, as well as other terms and conditions.[175]

On April 28, 2011, the FERC issued an order denying rehearing.[176] The FERC first rejected Northern's contention that the Commission recognized its right to apply market-based rates to resales of capacity in a 2007 order.[177] The FERC concluded that the statutory language was clearly limited to "new" construction and could not be applied to already-constructed capacity, and that the scope of authorization applied for and granted in the 2006 Order was limited to the initial capacity auction and resulting initial contracts.[178] The FERC denied that the ruling would deprive Northern of the right to recover its costs.[179] The FERC also rejected Northern's request to cap resale rates at the original contract prices,[180] as well as Northern's challenge to the requirement that the reserve price in a resale auction be the just and reasonable rate on file.[181]

In another Northern Natural Gas Co. order, the FERC issued an order authorizing construction of new storage facilities but denied market-based rate authority under NGA section 4(f).[182] Northern proposed to build facilities (including additional base gas and higher deliverability) to convert 2 Bcf of existing interruptible storage capacity to firm capacity, subject to market-based rates determined by a prior open season.[183] The FERC granted the certificate but rejected the request for market-based rates because "Northern's proposal [would] not increase the currently-certificated working gas capacity" of its storage facility, but would only change the quality of service from interruptible to firm;[184] "Northern [did] not assert that it was unable to obtain sufficient long-term commitments at cost-based rates to support its project or otherwise demonstrate that market-based rates were necessary for it to secure financing for the project;"[185] and Northern only stated that "without market-based rate authority, it will not proceed with the project."[186] The FERC determined that "this assertion alone, especially in the context of what [it found] to be a relatively low-risk undertaking for an established natural gas company, [was] insufficient to support a determination that 'market-based rates are in the public

174. *Id*. at P 11.
175. *Id*. at P 12.
176. *Northern Natural Gas Co*., 135 F.E.R.C. ¶ 61,085 (2011).
177. *Id*. at PP 7-10.
178. *Id*. at PP 12-14.
179. *Id*. at P 18.
180. *Id*. at P 21.
181. *Id*. at P 24.
182. *Northern Natural Gas Co.*, 134 F.E.R.C. ¶ 61,247 at P 1 (2011).
183. *Id.* at P 21.
184. *Id.*
185. *Id.*
186. *Id.*

interest and necessary to encourage the construction of the storage capacity.'"[187] The FERC distinguished its authorization of market-based authority for incremental capacity authorized in the Redfield project in 2006[188] and further found that the proposed project did not raise sufficient risk for an established pipeline such as Northern to justify market-based rates.[189] The FERC concluded that Northern did not demonstrate that customers were given the opportunity to contract for it at cost-based rates and also concluded that Northern could supply rate certainty by means of its negotiated rate authority.[190] The FERC further faulted Northern for not supporting a reserve price or providing a recourse rate for shippers.[191]

In *UGI Storage Co.*, the FERC issued an order granting abandonment authority, issuing certificates, and granting market-based rate authority.[192] UGI Central Penn Gas, Inc. (CPG) proposed to abandon its storage service and transfer its storage facilities to UGI Storage Company (UGI Storage), an affiliate, which would own and operate CPG's former storage facilities as an interstate storage company, at market-based rates.[193] UGI Storage had submitted an application for market-based rates similar in content and support to others filed by independent storage projects in New York/Pennsylvania geographic market.[194]

The FERC found that UGI Storage had met the standards for market-based rates, given its low market shares, moderate HHIs, and consistency with other companies consistently granted market-based rate authority since 1994.[195] UGI Storage had also demonstrated significant supplies of local flowing gas that further reduced the market concentration.[196] The FERC further found that the competitive factors supporting market-based rates for other small storage companies in the same geographic market were applicable to UGI Storage, "regardless of the fact that UGI Storage will be using existing storage capacity acquired from CPG."[197]

The FERC subsequently denied rehearing.[198] The FERC rejected a requested stay[199] and rejected the argument that CPG's rate settlement with the Pennsylvania Commission resulted in unduly discriminatory rates *vis a vis* other storage customers under the new interstate service.[200] The FERC confirmed that even if UGI Storage were viewed as an existing storage company charging cost-based rates, the applicant should be judged on whether it could charge more than

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187. *Id*. at PP 21-28.
188. *Id*. at PP 25-26.
189. *Id*. at PP 28-29.
190. *Id*. at PP 31-32.
191. *Id*. at PP 34-35.
192. *UGI Storage Co.*, 133 F.E.R.C. ¶ 61,073 (2010) [hereinafter *UGI Storage I*], *reh'g denied and clarification granted*, *UGI Storage Co.*, 134 F.E.R.C. ¶ 61,239 (2011) [hereinafter *UGI Storage II*].
193. *UGI Storage I*, *supra* note 192, at P 1.
194. *Id.* at P 64.
195. *Id*. at PP 80-81.
196. *Id*. at PP 97-98.
197. *Id*. at P 85.
198. *UGI Storage II*, *supra* note 192, at P 2.
199. *Id*. at PP 17-23; *see also id.* discussion at PP 63-66.
200. *Id*. at PP 25-30.

the competitive level, which might be well above 10% more than the embedded cost levels.[201] The FERC also reaffirmed the use of subscribed capacity in the market power analysis because of evidence of active capacity release in the market,[202] because of the substantial and expanding local gas supplies,[203] and because of available capacity release from major cost-based storage providers.[204] The FERC emphasized again the importance of demonstrated, easy entrance by new storage providers.[205]

K. Mobile-Sierra

In *Maine Public Utilities Commission v. FERC*, the D.C. Circuit considered, on remand from the Supreme Court, challenges to the "FERC's approval of a settlement that redesigned New England's electricity capacity market."[206] The D.C. Circuit previously had granted the petitions because the settlement required later challenges to rates resulting from the settlement auction procedures, even from non-settling parties, to be subject to the *Mobile-Sierra* standard of review.[207] The DC Circuit considered *Mobile-Sierra* to be a form of estoppel applied to a contracting party.[208]

The Supreme Court reversed and remanded concluding that because of the presumed equivalence of bargaining power of the contracting parties, *Mobile-Sierra* creates a presumption that the contract is just and reasonable and, accordingly, the *Mobile-Sierra* standard applies to challenges by non-parties to the contract.[209]

Left unresolved was whether the auction rates were the kind of rates to which *Mobile-Sierra* applied. In its consideration on remand in *Devon Power LLC,* the FERC found that, although auction rates were not contract rates that necessarily would have triggered *Mobile-Sierra,* when faced with challenges to non-contract rates, circumstances may make it appropriate to apply a more rigorous standard of review.[210] The FERC found such circumstances present because: (i) auctions are a market mechanism that appropriately value capacity; (ii) rate instability is undesirable for generating units' reliability; and (iii) a rigorous standard promotes rate stability.[211]

In *High Island Offshore System, LLC* (HIOS)**,** the FERC required modification of an uncontested settlement to eliminate the application of the *Mobile-Sierra* standard to future customers and the FERC, distinguishing between contract rates that automatically would have triggered *Mobile-Sierra*

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201. *Id*. at PP 37-41. The prices being paid for UGI Storage's services per its open season were far above the previous cost-based rates charged by CPG.

202. *Id*. at P 42.

203. *Id*. at PP 42-44.

204. *Id*. at P 45.

205. *Id*. at P 46. The Commission also rejected other arguments specifically relating to CPG's obligations under its certificate and the 1992 settlement.

206. Maine Pub. Utils. Comm'n v. FERC, 625 F.3d 754, 755 (D.C. Cir. 2010).

207. *Id.*

208. Maine Pub. Utils. Comm'n v. FERC, 520 F.3d 464, 477 (D.C. Cir. 2008) (*per curiam*).

209. NRG Power Mktg., LLC v. Maine Pub. Utils. Comm'n, 130 S. Ct. 693, 696-98 (2010).

210. *Devon Power LLC*, 134 F.E.R.C. ¶ 61,208 at P 2 (2011).

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

and tariff rates applicable to all present and future HIOS customers, to which the *Mobile-Sierra* presumption did not apply in the absence of compelling circumstances.[212]

Shortly after, in two orders issued on the same day, *Petal Gas Storage, LLC* (Petal Gas)[213] and *Southern LNG Co.* (Southern LNG),[214] the FERC applied the same analysis and required modification of settlement provisions in uncontested settlements that would have subjected future challenges to settlement tariff provisions to the *Mobile-Sierra* standard.[215] In both cases, the FERC found that the settlement was not a contract to which *Mobile-Sierra* automatically applies and as a result, absent compelling circumstances such as were present in *Devon Power*, it will not approve the use of a *Mobile-Sierra* standard applicable to itself or non-settling third parties.[216]

L. *Non-Conforming Provisions*

In *Viking Gas Transmission Co.*, the FERC considered whether pipelines may include contractual rollover provisions and right of first refusal (ROFR) provisions in agreements that differ from the regulatory ROFRs that the Commission requires.[217] The FERC explained that "[a]n automatic renewal provision . . . is a valuable substantive right [that] goes beyond simply filling in a blank" and, as such, was an impermissible material deviation because the tariff lacked the non-discriminatory negotiation provision.[218] The FERC required Viking to remove the language or offer the automatic renewal to all similarly-situated shippers in a generally applicable tariff.[219]

In *Questar Pipeline Co.*, the FERC determined that "a provision that decrease[d] the contract quantity for each year of the contract" was an impermissible nonconformity and that a single blank for term and quantity on the *pro forma* Service Agreement, "with no explanation, did not provide sufficient notice" to other shippers.[220] The FERC required Questar to add a statement to its service agreement to inform shippers that "the blanks can be filled in with multiple terms and quantities."[221] Pipelines are required to give sufficient notice to all similarly-situated shippers of all negotiable contractual rights, and blank spaces on the service agreement generally do not provide adequate notice.[222]

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212. *High Island Offshore Sys.*, *LLC*, 135 F.E.R.C. ¶ 61,105 at PP 17-20 (2011).

213. *Petal Gas Storage, LLC,* 135 F.E.R.C. ¶ 61,152 (2011).

214. *Southern LNG Co.*, 135 F.E.R.C. ¶ 61,153 (2011).

215. In *Petal Gas* the subject was settlement recourse rates. In *Southern LNG*, the subject was tariff gas quality and interchangeability provisions.

216. 135 F.E.R.C. ¶ 61,152 at P 1; 135 F.E.R.C. ¶ 61,153 at P 1.

217. *Viking Gas Transmission Co*., 132 F.E.R.C. ¶ 61,099 at P 14 (2010) (citing *Gulf South Pipeline Co*., 118 F.E.R.C. ¶ 61,262 at P 33 (2007)); *Id.* at P 16 (noting that contractual ROFRs would only be used for shippers who do not qualify for the regulatory ROFRs under section 284.221(d)(2)).

218. *Id.* at P 15 (citing *Questar Southern Trails Pipeline Co.,* 130 F.E.R.C. ¶ 61,234 at P 6 (2010)).

219. *Id*.

220. *Questar Pipeline Co.*, 132 F.E.R.C. ¶ 61,152 at PP 2, 7 (2010).

221. *Id*. at P 7.

222. *Id.* at P 2.

In *Tuscarora Gas Transmission Co.*, the FERC found a maximum transmission quantity (MTQ) step-down provision to be impermissibly nonconforming with the pipeline's service agreement because it was not clear in the service agreement that the shipper had the option to choose different MTQs for specific time periods.[223] The FERC directed the pipeline to add multiple blanks to the *pro forma* service agreement to indicate the availability of negotiations of multiple terms and quantities.[224]

In *Northern Natural Gas Co.*,[225] the FERC accepted Northern's revised tariff sheets that amended provisions of its firm rate schedules and its General Terms and Conditions to remove certain "hardship reduction provisions that allow shippers to reduce firm entitlements" if a firm industrial customer bypasses the LDC or permanently ceases operations.[226] The hardship reduction provision was part of a 1992 settlement.[227] The FERC accepted the revisions because pipelines are not required to offer such options and Northern's Memphis clause allowed it to make such tariff changes.[228]

M. Notices

In *Tennessee Gas Pipeline Co.*, the FERC accepted a filing by Tennessee to modify its tariff provisions governing notice to shippers of interruptions in service due to scheduled routine maintenance.[229] The FERC found that Tennessee's proposal to eliminate its previous prohibition on such service interruptions from November to April and to shorten the advance notice of such service interruptions was supported by Tennessee's assertions that (1) its market conditions no longer reflected a solely a winter peak, but instead a dual winter/summer peak, due primarily to the growth of electric generation load in its market area and that (2) the pattern of gas flows on its system had changed significantly due to the growth of shale gas production in the middle of its system.[230] The FERC further found Tennessee's proposed provision "consistent with the tariff provisions of other pipelines," providing greater flexibility "to schedule maintenance throughout the year."[231]

N. Open Seasons

In *Texican N. La. Transport v. Southern Natural Gas Co.*, the FERC considered whether, in an open season, a pipeline may aggregate portions of bids to determine the highest net present value (NPV) to the pipeline and award capacity accordingly.[232] The Southern Natural Gas Company (SONAT) open

223. *Tuscarora Gas Transmission Co.,* 131 F.E.R.C. ¶ 61,091 at P 9 (2010), *reh'g denied* 134 F.E.R.C. ¶ 61,172 (2011).

224. *Id*.

225. *Northern Natural Gas Co.*, 133 F.E.R.C. ¶ 61,103 (2010), *reh'g denied* 135 F.E.R.C. ¶ 61,024 (2011).

226. *Id.* at P 3.

227. *Id.*

228. *Id.* at PP 18-19.

229. *Tennessee Gas Pipeline Co.*, 133 F.E.R.C. ¶ 61,191 (2010).

230. *Id*. at P 16.

231. *Id.* at P 17.

232. *Texican N. La. Transport, LLC v. Southern Natural Gas Co.*, 132 F.E.R.C. ¶ 61,167 (2010).

season notice contained a statement reserving its "right to aggregate bids that generate the highest [NPV]."[233] Finding that Texican had not satisfied its burden to demonstrate that SONAT's allocation methodology or open season procedures violated FERC policy or the pipeline's tariff,[234] the FERC noted its overriding policy that "capacity [be] awarded to the highest valued use."[235] The FERC explained that open seasons and NPV evaluations are a tool for determining such use.[236] The FERC concluded that in appropriate circumstances a partial aggregation of capacity maximizes the efficient use of the pipeline system, increases the amount of gas that is transported to the market for consumers, and creates the ultimate benefit to the existing shippers on the pipeline through lower rates.[237]

In *Gulf South Pipeline Co.,*[238] the FERC clarified its holding in *Texican*, explaining that its order in that case did not require a pipeline to maximize the amount of capacity awarded.[239] Rather, the FERC approved a methodology that awarded capacity to the highest valued use in order to maximize efficient use of the pipeline system, in accordance with its policy.[240] In addition, the FERC accepted Gulf South's proposal to: (1) add an exception for the construction of "facilities that will result in a material increase in gas usage or production" to its rule that a party may not request service more than 90 days prior to the commencement of service;[241] (2) add language to its tariff "to ensure that all capacity awarded through a partial award of capacity will have a constant Maximum Daily Quantity (MDQ) for the term of the agreement unless the capacity is awarded under a rate schedule that allows for seasonal MDQs;"[242] and (3) eliminate "partial awards of capacity when there is no capacity available at some period during the requested term."[243]

In *Pine Prairie Energy Center, LLC*,[244] the FERC determined that the requirements to hold an open season and to solicit turn-back capacity applied to storage projects even where the storage provider is authorized to charge market-based rates.[245] The FERC explained that "the policy considerations that support [its] open season requirements are separate and unrelated to the market considerations [that it] uses to evaluate a market-based rate proposal."[246] Further, the FERC found "that [its] turn-back open season policies . . . appropriately balance the need for additional infrastructure while mitigating the potential for overbuilding, the associated environmental impacts and

233. *Id.* at PP 3, 17.
234. *Id.* at PP 34, 48.
235. *Id.* at P 26.
236. *Id.*
237. *Id.*
238. *Gulf S. Pipeline Co.*, 135 F.E.R.C. ¶ 61,119 (2011).
239. *Id.* at P 24.
240. *Id.*
241. *Id.* at P 6.
242. *Id.* at P 2.
243. *Id.*
244. *Pine Prairie Energy Ctr., LLC*, 135 F.E.R.C. ¶ 61,168 (2011).
245. *Id.* at P 36.
246. *Id.* at P 32.

condemnation of property."[247] Finally, the FERC agreed with Pine Prairie that "the requirement to solicit turn-back capacity does not mean that a shipper simply can walk away from its contractual obligations;" rather, a pipeline "can require shippers . . . to meet reasonable terms designed to keep the company financially whole."[248]

In *Turtle Bayou Gas Storage Co.*,[249] the FERC denied an application filed by Turtle Bayou Gas Storage Company, LLC (Turtle Bayou) for authorization under NGA section 7(c) to construct and operate a 12 Bcf natural gas storage facility in Liberty and Chambers counties, Texas.[250] In its application, Turtle Bayou requested market-based rate authority.[251] The FERC denied the application because Turtle Bayou had failed to conduct an open season and to negotiate and secure the necessary surface and sub-surface property rights (Turtle Bayou proposed relying on eminent domain to secure the necessary rights).[252]

O. Operational Sales

In *Southern Natural Gas Co.*, the FERC accepted, subject to modification, SONAT's tariff provisions governing operational purchases and sales of gas, which SONAT uses to address matters including system pressure, line pack, storage inventories, fuel balancing, and shipper balancing transactions.[253] The FERC required two changes to SONAT's tariff to make it consistent with the Commission's established policies governing operational purchases and sales. First, it required SONAT to make all of its operational sales subject to bidding.[254] Second, it required SONAT to provide an annual report of its operational purchases and sales, detailing the source of the gas purchased or sold, the date of each purchase or sale, the volume, sale price, costs, and revenues from each transaction, the disposition of the costs and revenues, and an explanation of the purpose of each transaction.[255] With regard to SONAT's arguments that it already reports the data, the FERC deemed Form 552 insufficient, but it allowed SONAT to address some of the reporting either through a combination of a new report and its existing reports regarding fuel and imbalances, or to combine all of the reporting into one report.[256]

In *Blue Lake Storage Co.*, the FERC accepted subject to modification Blue Lake's tariff provisions governing operational purchases and sales of gas.[257] The FERC required two changes to Blue Lake's tariff to make it consistent with established policies. First, it required Blue Lake to make all of its operational

247. *Id.* at P 34.
248. *Id.* at P 35.
249. *Turtle Bayou Gas Storage Co.,* 135 F.E.R.C. ¶ 61,233 (2011).
250. *Id.* at P 1.
251. *Id.*
252. *Id*. at P 33.
253. *Southern Natural Gas Co.*, 133 F.E.R.C. ¶ 61,183 at P 10 (2010).
254. *Id.* at P 12.
255. *Id.* at P 18.
256. *Id*. at P 20.
257. *Blue Lake Storage Co.*, 132 F.E.R.C. ¶ 61,177 at P 1 (2010).

sales subject to bidding.[258] Second, it required Blue Lake to provide a detailed annual report of its operational purchases and sales, rejecting Blue Lake's arguments that the FERC's Form Nos. 2-A and 3-Q provide sufficient transparency.[259] The FERC noted that the forms provide aggregate data that does not provide enough detail to meet the Commission's operational purchase and sale reporting requirements.[260]

P. Penalties

In *Columbia Gulf Transmission Co.*, the FERC approved Columbia Gulf's proposed Scheduling Variance Service (SVS).[261] The SVS allows firm shippers or delivery point operators to negotiate an amount by which their actual deliveries may differ from their scheduled quantities beyond the daily tolerance level specified in the tariff, without incurring daily scheduling penalties.[262] The FERC found that the SVS is consistent with its policy of allowing pipelines to provide services to shippers to avoid imbalance penalties, as reflected in Order No. 637.[263] The FERC rejected intervenors' degradation of service claim, finding that they failed to identify any firm entitlement to service that would be adversely affected by the SVS.[264] The FERC consolidated this docket with Docket No. RP11-1435, Columbia Gulf's general NGA section 4 rate proceeding (discussed below), and set the determination of SVS rates for hearing as part of the consolidated proceeding.[265]

In another *Columbia Gulf Transmission Co.* order, the FERC approved a number of non-rate tariff revisions proposed by Columbia Gulf as part of its NGA section 4 rate case.[266] Columbia Gulf's tariff changes included both new penalty provisions and a new service to allow shippers to avoid certain penalties. The FERC conditionally approved a proposal authorizing Columbia Gulf to require shippers to install flow control devices at their own expense if they violate specified tariff conditions or incur scheduling variances of a specified magnitude and frequency.[267] The FERC made clear that "the cost of installing flow control equipment is rightly borne by the operator causing the operational problem."[268] The FERC's approval was conditioned on a subsequent compliance filing detailing how Columbia Gulf would operate the flow control devices once installed.[269]

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258. *Id.* at P 7.
259. *Id.* at P 8.
260. *Id.*.
261. *Columbia Gulf Transmission Co.*, 134 F.E.R.C. ¶ 61,082 (2011).
262. *Id.* at P 4. The SVS allows customers to avoid the Delivery Point Scheduling Penalty approved by the FERC in Docket No. RP07-174-000. *Id.* at P 2.
263. *Id.* at P 14.
264. *Id.* at P 24.
265. *Id.* at P 1.
266. *Columbia Gulf Transmission Co*., 135 F.E.R.C. ¶ 61,106 (2011) [hereinafter *Columbia Gulf 2*].
267. *Id.* at P 48.
268. *Id.* at P 50.
269. *Id.* at P 51. Columbia Gulf made the required compliance filing on May 31, 2011.

The FERC also approved Columbia Gulf's unauthorized gas penalty.[270] Initially, Columbia Gulf had proposed to apply its penalty to any volume of gas that exceeded a confirmed nomination.[271] The FERC limited the application of the penalty to excess receipts into Columbia Gulf's pools, finding the pipeline had only presented evidence that receipts at pools, and not at physical delivery points, could potentially cause service problems.[272]

The FERC rejected Columbia Gulf's proposed hourly scheduling penalty.[273] The FERC made clear that when seeking hourly penalties, a pipeline must make a "convincing and fully supported showing of a need for such penalties to protect system integrity."[274] While pipelines "need not wait for a system failure,"[275] Columbia Gulf failed to provide evidence that its system was experiencing negative impacts from hourly variances.[276]

The FERC approved Columbia Gulf's proposed Enhanced Firm Transportation (EFT) service, which is intended to allow shippers to avoid the proposed hourly scheduling penalty by taking firm deliveries at non-uniform hourly rates.[277] Despite rejecting the hourly scheduling penalty, the FERC found that the EFT service is consistent with previously approved proposals, which similarly provided shippers with additional flexibility.[278] The applicable rate for the EFT is set for hearing as part of Columbia Gulf's general rate proceeding.[279]

Q. Pooling Points

In *Transcontinental Gas Pipe Line Corp.*, the FERC granted rehearing and accepted Transco's proposal to establish two pools (a Zone 4 Pool and a Zone 4A Pool) in the vicinity of its Station 85, as long as pool to pool transfers were permitted.[280] Noting the extensive background of the proceeding, which involved a prior order in which the FERC had determined that Transco's charging of two fuel and usage charges for pooled receipts at Station 85 "was unjust and unreasonable because it discouraged . . . pooling,"[281] the FERC stated that the situation was more complicated at Station 85 as the role of the Mobile Bay Lateral, which is connected to Station 85, had "changed from a lateral feed[er] . . . to one that can move gas in both directions."[282] The FERC concluded that because Station 85 has become a market center moving gas in both directions on the Mobile Bay Lateral, the existence of a single Zone 4 rate at Station 85 does not result in just and reasonable rates.[283] The FERC required

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270. *Id.* at P 108.
271. *Id.* at P 95.
272. *Id.* at P 109.
273. *Id.* at P 85.
274. *Id.* at P 86.
275. *Id.* at P 92.
276. *Id.* at PP 87-91.
277. *Id.* at P 113.
278. *Id.* at PP 130–31.
279. *Id.* at P 129.
280. *Transcontinental Pipe Line Corp.,* 132 F.E.R.C. ¶ 61,034 at P 34 (2010).
281. *Id.* at P 6.
282. *Id.* at P 26.
283. *Id.* at P 29.

Transco to establish two pools in the Station 85 vicinity, directing Transco to "charge only for withdrawal transportation from these pools and [to] permit the transfer of volumes between [the] pools subject to the appropriate charges for such transfers."[284]

In *Gulf South Pipeline Co.*, the FERC approved as just and reasonable revised tariff records filed by Gulf South Pipeline to divide its Pooling Area 7 into two pools at its Hall Summit compressor station.[285] Gulf South had proposed to divide "Pooling Area 7, at the point of the constraint" at the Hall Summit compressor station into two pools, explaining that it was experiencing capacity constraints in the center of the Pooling Area due in part to increased production from the Haynesville shale area.[286] The FERC concluded that Gulf South had "provided sufficient justification for redefining" its pools and approved Gulf South's proposal.[287] The FERC explained that in order "[f]or a pool to work efficiently, the receipt points feeding the pool need to be operationally similar, so that there is no . . . difference between scheduling gas from a particular receipt point and scheduling gas from the pool."[288] The FERC added that "[p]ooling is not intended to provide transportation across operational constraints."[289] The FERC was persuaded that the existence of an ongoing constraint at Hall Summit justified the division of the pool.[290]

R. Rate Cases

Several pipelines filed rate cases pursuant to NGA section 4, which were suspended and set for hearing and/or technical conference. In two cases, the FERC approved uncontested settlements. Specifically, in *Granite State Gas Transmission, Inc.,*[291] the FERC suspended a rate increase reflecting a 40% common equity ratio and an 11.5% equity return[292] but rejected a proposed capital cost surcharge tracking mechanism to collect costs associated with: (1) replacing deteriorated pipe; (2) complying with the Pipeline Safety Act and (3) relocating portions of its pipeline to accommodate a state transportation project.[293] Ultimately, the FERC approved an uncontested settlement.[294] Second, in *Enbridge Offshore Pipelines (UTOS) LLC*, [295] the FERC suspended increases in firm and interruptible rates reflecting a substantial loss of load and allowed certain other proposals to become effective,[296] including a supplemental management fee for operating expenses, a rate adjustment mechanism triggered in the event throughput changes more than 10% annually, an event surcharge,

284. *Id.* at P 34.
285. *Gulf S. Pipeline Co.,* 132 F.E.R.C. ¶ 61,199 at P 4 (2010).
286. *Id.* at PP 3-4.
287. *Id.* at P 51.
288. *Id.* at P 53.
289. *Id.*
290. *Id.* at PP 56-57.
291. *Granite State Gas Transmission, Inc*., 132 F.E.R.C. ¶ 61,089 (2010).
292. *Id.* at P 9.
293. *Id.* at P 10.
294. *Granite State Gas Transmission, Inc*., 134 F.E.R.C. ¶ 61,074 at P 1 (2011).
295. *Enbridge Offshore Pipelines (UTOS) LLC*, 133 F.E.R.C. ¶ 61,106 (2010).
296. *Id.* at P 33

and a charge for removal of free water from its pipeline.[297] The FERC-approved settlement: (i) "establishes a mechanism by which UTOS will abandon its system, while maintaining transportation service . . . to shippers as they transition off;" (ii) "provides for lower increases in the . . . maximum recourse transportation rates . . . than [originally] proposed;" and (iii) eliminates the event surcharge and transportation quantity adjustment provision.[298]

The Portland Natural Gas Transmission System (PNGTS) rate case was fully litigated before the FERC. In *Opinion No. 510*,[299] the FERC affirmed the ALJ's finding that Portland's use of a twenty-one-year levelization period commencing on April 1, 1999 and ending on March 31, 2020, was consistent with the language of the 2002 Settlement.[300] The FERC also affirmed the ALJ's rejection of Portland's proposal to increase its O&M annually to reflect an escalation clause in service contracts with its majority owner because, absent an agreement respecting these costs, they must be considered under traditional test period method.[301] "The inflation adjustments sought by Portland [were] neither known nor measurable nor would they take effect during the test period . . . ."[302]

The FERC determined that restricting its analysis of Portland's pipeline integrity and maintenance expenses to the test period would be unrepresentative of future expenditures and adopted a proposal to use a four year average of non-contiguous data sequences.[303] The FERC affirmed the ALJ's recognition of a contractual fee increase for outside services which took place during the test period[304] but reversed the ALJ's reliance on "cost data provided in the 45-day update filing, rather than Portland's updated cost data, which presented actual taxes . . . during the test period."[305]

The FERC affirmed the ALJ's determinations respecting regulatory commission expenses, in which the ALJ relied on Portland's updated balance of Account 928, excluding amounts outside of the test period and averaging the result over five years on the grounds that Portland is not likely to file a rate case more frequently than every few years.[306] The FERC found that Portland "failed to support its exception" and that its exhibits failed "to explain how Portland developed its cost data," or to enable the FERC "to determine whether [Portland's proposed] additional expenses . . . occurred in, or prior to, the test period."[307]

The FERC affirmed the ALJ's exclusion of claimed interim retirements in negative salvage expenses because the record demonstrated that there were no interim plant retirements to be valued.[308] The FERC found Portland's evidence

297. *Id*. at PP 17-19.

298. *Enbridge Offshore Pipelines (UTOS) LLC*, 135 F.E.R.C. ¶ 61,096 at P 7 (2011).

299. *Portland Natural Gas Transmission Sys.*, 134 F.E.R.C. ¶ 61,129 (2011).

300. *Id*. at PP 47-52.

301. *Id.* at PP 65-68.

302. *Id*. at PP 69-70.

303. *Id*. at P 86.

304. *Id*. at P 93.

305. *Id*. at P 100.

306. *Id.* at PP 101-02.

307. *Id*. at P 110.

308. *Id*. at P 117.

to be insufficient to support a prospective increase to its composite depreciation rate to 3.53%.[309] The FERC also affirmed the ALJ's decision to apply the same recovery period for negative salvage as for depreciation rates[310] and inclusion of prepaid tax in the working capital allowance included in rate base, excluding amounts paid outside of the test period.[311] The FERC approved a proxy group for purposes of determining rate of return on equity consisting of: TC Pipelines, Southern Union, Boardwalk, Spectra Corp., El Paso Partners and Spectra Partners, finding that these companies "are more risk appropriate to Portland than the other companies proposed by the parties."[312] The FERC's DCF analysis established a return "zone of reasonableness of 12.18 percent to 14.89 percent, with a median of 12.99 percent."[313] The FERC affirmed the ALJ's conclusion "to set Portland's [return of equity] at the median of the proxy group range."[314] The FERC also affirmed the ALJ's decision "to establish Portland's at-risk condition at a level of 210,840 Dth per day . . . to place Portland at-risk for any unsubscribed capacity."[315] The FERC rejected Portland's proposal "to design its rates based upon its design capacity . . . without any express allocation of costs to its IT and PAL services [and] to continue its preexisting practice of not crediting any interruptible revenues against its cost-of-service."[316] The FERC required "Portland to allocate costs to its IT/PAL service based upon a projected volume of interruptible transportation, subject to the condition that Portland's overall . . . volumes must satisfy the at-risk condition."[317]

The FERC also considered the extent to which Portland should retain the "gross bankruptcy proceeds that it received" from the early termination of rejected 20-year firm transportation agreements that "were terminated as part of [a shipper's] bankruptcy proceedings."[318] "Portland filed bankruptcy claims . . . [and] recovered a net total of $119,761,258 in bankruptcy proceeds before and during the test period . . . ."[319] The FERC concluded that

> Portland must include in its rate design volumes both: (1) the [total] Dth per day of contract demand associated with the [agreements], subject to a discount adjustment to reflect . . . [the partial compensation to] Portland for loss of those maximum rate contacts; and (2) the interruptible and short-term firm billing determinants associated with its remarketing of the capacity. In addition, Portland [was required to] reduce rate base for the bankruptcy proceeds[, net of legal costs.][320]

The FERC found that the "reduction to Portland's rate base [was] justified to account for the fact the bankruptcy award allowed Portland to recover

309. *Id*. at P 128.
310. *Id*. at P 125.
311. *Id*. at P 155.
312. *Id*. at P 218.
313. *Id*. at P 225.
314. *Id*. at P 265.
315. *Id*. at P 290.
316. *Id.* at P 307.
317. *Id*.
318. *Id.* at P 315.
319. *Id.*
320. *Id*. at P 350.

immediately costs that would otherwise have been recovered only over the remaining terms of the [agreements.]"[321]

In *El Paso Natural Gas Co.*, the FERC denied Phelps Dodge Corporation's (Phelps Dodge) request for rehearing in connection with the FERC's determination that an El Paso Settlement applied to consenting parties as well as Phelps Dodge, a non-consenting party.[322] The FERC found that *Trailblazer* approaches I and II were properly applied to the 2006 Settlement: under *Trailblazer* I, it had an adequate record on which to base a decision, and under *Trailblazer* II, the 2006 Settlement, as a package, was just and reasonable, and would put Phelps Dodge in no worse a position than if the case were litigated.[323] In its August 24, 2010 Order on Rehearing in the same proceeding, the FERC disposed of requests for rehearing of a September 5, 2008 Order that considered the applicability of a provision in a 1996 settlement to El Paso and its shippers.[324]

In its October 29, 2010 suspension order in *El Paso Natural Gas Co.*, the FERC accepted and suspended, for the maximum period, El Paso's proposed rate increase and changes to its terms and conditions of service.[325] A decline in throughput and decreased "prices received for short-term services and long-term contract renewals" resulted in rate increases on the order of "30 to 50 percent depending on" the zone of service.[326] The FERC rejected alternate tariff records submitted by El Paso that the FERC concluded circumvented the rate cap established in the 1996 Settlement.[327]

In its November 10, 2010 Order on Rehearing in *El Paso Natural Gas Co.*, the FERC disposed of requests for rehearing of its August 5, 2008 suspension order in Docket No. RP08-426.[328] In its 2008 Rate Case, El Paso sought to encourage long-term contracting by providing rates for short-term (less than a year) firm services "capped at 250 percent of the related recourse rate."[329] The FERC denied summary rejection of the short-term rate proposal, finding the rates similar to "cost-based seasonal rates or term-differentiated rates" that previously had been approved and set the issue for hearing.[330] On rehearing, the FERC concluded that El Paso's short-term rate proposal was not a form of market-based rate.[331]

In its December 23, 2010 Order on Rehearing in *El Paso Natural Gas Co.*, the FERC disposed of requests for rehearing of its October 29, 2010 suspension order in Docket No RP10-1398.[332] The FERC considered the requests for rehearing and clarification to be the latest chapter of the continuation of the

321. *Id*. at PP 360-361.
322. *El Paso Natural Gas Co.*, 132 F.E.R.C. ¶ 61,139 (2011).
323. *Id*. at P 87.
324. *El Paso Natural Gas Co.*, 132 F.E.R.C. ¶ 61,155 (2010).
325. *El Paso Natural Gas Co*., 133 F.E.R.C. ¶ 61,104 at P 1 (2010).
326. *Id.* at PP 6, 11.
327. *Id*. at P 16.
328. *El Paso Natural Gas Co*., 133 F.E.R.C. ¶ 61,129 (2010).
329. *Id.* at P 2.
330. *Id.* at P 6.
331. *Id*. at P 19.
332. *El Paso Natural Gas Co*., 133 F.E.R.C. ¶ 61,253 (2010).

disputes regarding Article 11.2 of El Paso's 1996 settlement and whether that settlement provision continues to be just and reasonable and/or in the public interest.[333] The FERC found that the duration of Article 11.2 rate protection is not ripe for review because "the primary terms of the first set of Article 11.2 contracts do not expire until August 31, 2011, which is . . . beyond . . . the end of the test period."[334] "[T]he duration of Article 11.2 contracts will not be an issue until . . . a dispute arises and a party requests adjudication in a separate proceeding."[335]

Five other NGA section 4 rate cases were filed and are ongoing. Specifically, in *Stingray Pipeline Co.*,[336] Stingray's proposed rate reflected substantial increases[337] based on significant "declines in throughput . . . , significant increases in costs, the need to recover large negative salvage costs," a ten year remaining useful life and return on a 60% common equity ratio of 14.31%.[338] Stingray proposed to remove a cap on its event surcharge and a mechanism to automatically adjust its rates in the event of changes in its full-rate equivalent throughput of 10% per year.[339] The FERC accepted and suspended, for the maximum period, the proposed rate and tariff changes and set all issues for hearing and settlement judge procedures.[340]

Columbia Gulf Transmission Co.[341] filed to merge its "Mainline Zone and Onshore Zone into a single Market Zone with a postage stamp rate."[342] Its alternative (Primary Case) maintained its current rate zone structure.[343] Columbia Gulf also proposed "a new Enhanced Firm Transportation (EFT) service [to allow] shippers . . . to contract for non-uniform hourly takes on a firm basis"[344] and "new short-term firm (STF) reservation rates for firm service with contracts lasting less than one year."[345] Columbia Gulf also proposed a first-come, first-served basis for available capacity;[346] provisions allowing it "to consider a non-creditworthy shipper's risk of default when evaluating the shipper's bid for capacity;"[347] notification to "shippers that it will evaluate . . . bids in a capacity auction using" the start "date of service, prepayments, credit, and . . . cost of service," along with term and price;[348] reserve capacity for

333. *Id.* at P 11.

334. *Id.* at P 12.

335. *Id*.

336. *Stingray Pipeline Co*., 135 F.E.R.C. ¶ 61,099 (2011).

337. *Id.* at P 3. (Stingray proposed to increase its "FTS reservation rate from $4.4895 per [Dth] of maximum daily quantity per month to $25.68 per Dth of maximum daily quantity per month," and its IT "from $0.15 per Dth . . . to $0.8447 per Dth.").

338. *Id.* at PP 4, 8, 11.

339. *Id*. at P 13.

340. *Id*. at P 38.

341. *Columbia Gulf Transmission Co*., 133 F.E.R.C. ¶ 61,182 (2010).

342. *Id*. at P 7.

343. *Id.*

344. *Id.* at P 9.

345. *Id.* at P 10.

346. *Id.* at P 18.

347. *Id.* at P 19.

348. *Id.* at P 20.

expansion projects;[349] "a new Unauthorized Overrun Penalty [for] critical and non-critical periods;"[350] liquidated damages for a successful bidder's failing to execute a contract;[351] an Hourly Scheduling Penalty for critical and non-critical periods;[352] and installation of "flow control equipment at the expense of [the] shipper."[353] In its suspension order, the FERC rejected requests for rejection of the filing, suspended the proposed changes and made them subject to "the outcome of a technical conference and hearing procedures."[354] In its Order on Technical Conference,[355] the FERC rejected "Columbia Gulf's proposed hourly scheduling penalties" but otherwise generally accepted the non-rate tariff proposals, as revised after the technical conference.[356]

The FERC's suspension order in *Eastern Shore Natural Gas Co.,*[357] accepted and suspended certain of Eastern Shore's proposed tariff records but rejected Eastern Shore's proposed elimination of its T-1 Rate Schedule because abandonment authorization had not been granted.[358] The FERC also permitted Eastern Shore to make effective subject to refund a proposed revenue credit for IT services coupled with a sharing mechanism if revenues exceeded the proposed level.[359]

On November 30, 2010, Tennessee Gas Pipeline Company (Tennessee)[360] initiated a rate case pursuant to section 4 of the NGA in which Tennessee proposed substantial increases in rate base,[361] inclusion of facilities for which abandonment authorization had been granted,[362] a proposed 13.5% return on an equity ratio,[363] a debt/equity ratio of 54.54%, and a change to the Straight Fixed Variable rate design.[364] Tennessee also proposed new trackers for hurricane cost recovery and for fuel, gas lost, and electric power used in compressor units, and a variety of tariff mechanisms, including changes to the time required for waiver notices, OFO action alerts, scheduling priorities, and open seasons, as well as to eliminate unused balancing options, to change cash-out procedures, and to add procedures for seeking a discount-type adjustment for certain negotiated rate agreements and a charge for failure to cycle gas in storage.[365]

349. *Id.* at P 22.

350. *Id.* at P 24.

351. *Id.* at P 27.

352. *Id.* at P 28.

353. *Id*. at P 31.

354. *Id*. at PP 2, 55.

355. *Columbia Gulf 2*, *supra* note 266.

356. *Id.* at PP 24-25.

357. *Eastern Shore Natural Gas Co.*, 134 F.E.R.C. ¶ 61,069 (2011).

358. *Id.* at P 1. "Rate Schedule T-1 is a firm transportation service provided by Eastern Shore" to two companies. It "has a scheduling priority below that of other firm transportation service at primary points but above that of firm transportation service utilizing secondary receipt and delivery points." *Id*. at n.3.

359. *Id.* at P 5.

360. *Tennessee Gas Pipeline Co*., 133 F.E.R.C. ¶ 61,266 (2010).

361. *Id.* at P 1.

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

363. *Id.* at P 6.

364. *Id.*

365. *Id.* at P 7.

In its suspension order, the FERC permitted the rate and tariff revisions to become effective, subject to refund at the conclusion of the suspension period and allowed the facilities subject to abandonment authorization to remain in rates, subject to the condition that if the conditions precedent to their sale had been satisfied by the time Tennessee moved its rates into effect they would be removed.[366] In its later Order on Technical Conference[367] the FERC accepted certain of Tennessee's proposals, subject to clarification, but rejected certain changes proposed to the order of scheduling priorities.[368] The FERC also permitted Tennessee to eliminate a variety of services that had not been used during the sixteen years since its last rate case.[369] The technical conference did not resolve factual issues about Tennessee's proposal to assess a charge for failure to cycle gas in storage. Accordingly, the FERC permitted the parties to present the facts at the hearing and permitted the proposal to go into effect subject to refund.[370]

On July 30, 2011, the FERC issued a suspension order in the general NGA section 4 rate case filed by Dominion Cove Point LNG, LP (Cove Point).[371] Cove Point proposed a reduction in recourse rates, with the exception of an increase in the commodity charge for LTD-1 service and the rate for LTD-2 interruptible service.[372] Cove Point also proposed tariff changes eliminating a retainage cap requirement for its FPS customers and modifying its tariff "to treat authorized overruns under its firm rate schedules on an equal basis with other interruptible services" for the purposes of capacity allocation and interruptions of service.[373] The FERC 1) accepted, effective July 1, 2011, the proposed rate reductions and the increased LTD-1 commodity rate, subject to refund, 2) suspended for the maximum period the LTD-1 authorized overrun charge and LTD-2 interruptible service charge, subject to refund, and 3) suspended the non-rate tariff changes for the maximum period subject to the outcome of a hearing and technical conference.[374]

S. *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.

In July 2010, the FERC approved uncontested settlements filed by *Natural Gas Pipeline Co. of America*[375] and *Great Lakes Gas Transmission, L.P.*,[376]

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366. *Id.* at P 1.

367. *Tennessee Gas Pipeline Co*., 135 F.E.R.C. ¶ 61,208 (2011).

368. The FERC rejected Tennessee's proposal to elevate the priority for secondary receipt to primary delivery points to the same level as primary to primary when there is a restriction in the shipper's primary path and to schedule secondary point transactions where the restriction is outside the shipper's path on an economic basis. *Id*. at PP 15-50.

369. *Id*. at PP 135-148.

370. *Id*. at PP 133-134.

371. *Dominion Cove Point LNG, LP*, 135 F.E.R.C. ¶ 61,276 (2011).

372. *Id.* at P 6.

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

374. *Id.* at PP 29-32.

375. *Natural Gas Pipeline Co. of Am.*, 132 F.E.R.C. ¶ 61,082 (2010).

376. *Great Lakes Gas Transmission, L.P.*, 132 F.E.R.C. ¶ 61,041 (2010).

thereby resolving the Commission-initiated investigations into their respective rates. The Commission also denied rehearing of its order terminating the investigation into the rates charged by *Northern Natural Gas Company*.[377]

In *Kinder Morgan Interstate Gas Transmission, LLC* (KMIGT), the FERC determined that KMIGT appeared to be recovering "revenue substantially in excess of its . . . costs of service and fuel" and lost and unaccounted-for gas based on the cost and revenue information provided by KMIGT in its 2008 and 2009 FERC Form No. 2 submissions.[378] The FERC initiated an investigation into the justness and reasonableness of KMIGT's rates.[379] The FERC subsequently granted partial rehearing of its requirement that KMIGT exclude from its cost and revenue study any adjustments to the 12-month base period data.[380] The FERC stated that it was not required to permit KMIGT to include adjustments for a full nine-month test period in an NGA section 5 proceeding,[381] and that to do so would be impractical.[382] However, the FERC stated that it would permit KMIGT to submit data for an abbreviated adjustment period in its answering testimony[383] and further permitted KMIGT to file "a separate cost and revenue study [to] reflect adjustments for changes [to KMIGT] projects that will occur during a time frame which may reasonably be taken into account in this proceeding."[384] KMIGT subsequently filed a Stipulation and Agreement of Settlement that would resolve the rate investigation proceeding, which the Presiding Administrative Law Judge certified[385] as uncontested to the Commission on June 9, 2011.[386]

In *Ozark Gas Transmission, L.L.C.*, the FERC determined that Ozark appeared to be recovering revenue substantially in excess of its costs of service and fuel and lost and unaccounted-for gas based on the cost and revenue information provided by Ozark in its 2008 and 2009 FERC Form No. 2 submissions.[387] The FERC initiated an investigation into the justness and reasonableness of Ozark's rates.[388] As with KMIGT, the FERC subsequently granted partial rehearing of its requirement that Ozark exclude from its cost and revenue study any adjustments to the twelve-month base period data.[389] The FERC also clarified that the Presiding Administrative Law Judge would have the authority to "modify the procedural schedule . . . , including the dates for the hearing and the initial decision," to account for the "use of data after the period

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377. *Northern Natural Gas Co.*, 133 F.E.R.C. ¶ 61,111 at P 1 (2010).

378. *Kinder Morgan Interstate Gas Transmission LLC*, 133 F.E.R.C. ¶ 61,157 (2010), *order on reh'g*, 134 F.E.R.C. ¶ 61,061 at P 6 (2011).

379. 134 F.E.R.C. ¶ 61,061 at P 1.

380. *Id.* at P 54.

381. *Id*. at P 41.

382. *Id*. at P 42.

383. *Id*. at P 50.

384. *Id*. at P 54.

385. *Kinder Morgan Interstate Gas Transmission LLC*, 135 F.E.R.C. ¶ 63,015 (2011).

386. *Id.*

387. *Ozark Gas Transmission, L.L.C.*, 133 F.E.R.C. ¶ 61,158 at P 9 (2010), *order on clarification and reh'g*, 134 F.E.R.C. ¶ 61,062 (2011), *order on clarification and reh'g*, 134 F.E.R.C. ¶ 61,193 (2011).

388. 134 F.E.R.C. ¶ 61,062 at P 1.

389. *Id.* at P 26.

covered by Ozark's cost and revenue study."[390] Ozark subsequently filed a Stipulation and Agreement. The Presiding Administrative Law Judge certified the uncontested Stipulation and Agreement to the Commission on June 9, 2011.[391]

On February 28, 2011, the Public Utilities Commission of Nevada and Sierra Pacific Power Company d/b/a NV Energy jointly filed a complaint against Tuscarora Gas Transmission Co. (Tuscorora) pursuant to NGA section 5, alleging that cost and revenue information provided by Tuscarora in its 2008 and 2009 FERC Form 2-A submissions showed that Tuscarora was recovering revenue substantially in excess of its cost of service and requested that the FERC initiate an investigation into Tuscarora's rates.[392] After reviewing Tuscarora's 2010 FERC Form No. 2-A, the FERC determined that the only significant changed circumstance since 2009 was a change in "its capital structure from approximately 30 percent equity to 70 percent equity."[393] Accordingly, the FERC initiated "an investigation to examine the justness and reasonableness of Tuscarora's rates," and singled out the reasonableness of Tuscarora's capital structure as an issue to be addressed at the hearing.[394]

T. Regulatory Assets

The FERC addressed regulatory asset accounting and its rate-making implications in two orders involving a dispute that arose in an ongoing proceeding concerning the transportation rates of *Kern River Gas Transmission Co.*[395] In its initial orders in the case, the FERC approved separate, new book depreciation rates for Kern River's turbine compressor engines and general plant and ruled that these assets must remain included in the determination of the "regulatory" depreciation expense that Kern River recovers in its levelized annual cost of service.[396] The FERC also held that differences between the annual book and regulatory depreciation related to compressors and general plant should be recorded as a regulatory asset or liability.[397]

The FERC's further statement that Kern River would be at risk for any book depreciation expense during "Period One"[398] led to a dispute concerning

390. 134 F.E.R.C. ¶ 61,193 at P 27.

391. *Ozark Gas Transmission, L.L.C.*, 135 F.E.R.C. ¶ 63,014 (2011).

392. *Public Utils. Comm'n of Nev. v. Tuscarora Gas Transmission Co.*, 135 F.E.R.C. ¶ 61,174 at PP 7-9 (2011).

393. *Id*. at P 27.

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

395. *Kern River Gas Transmission Co.*, 133 F.E.R.C. ¶ 61,105 (2010) [hereinafter *October 29 Order*]; *Kern River Gas Transmission Co.*, 133 F.E.R.C. ¶ 61,199 (2010) [hereinafter *December 6 Order*].

396. Opinion No. 486, *Kern River Gas Transmission Co.*, 117 F.E.R.C. ¶ 61,077 at PP 55-57, 464-476 (2006), *order on reh'g*, Opinion No. 486-A, 123 F.E.R.C. ¶ 61,056 at PP 366-369, 376-378 (2008), *order on reh'g*, Opinion No. 486-B, 126 F.E.R.C. ¶ 61,034, *order on reh'g*, Opinion No. 486-C, 129 F.E.R.C. ¶ 61,240 (2009), *order on reh'g*, Opinion No. 486-D, 138 F.E.R.C. ¶ 61,162 (2010).

397. *See generally* 123 F.E.R.C. ¶ 61,056 at P 371.

398. "Period One" refers to the duration of Kern River's firm transportation shippers' current service agreements. *Id.* at P 2.

whether Kern River may properly recover in "Period Two" rates[399] any regulatory asset related to depreciation of compressors and general plant that remains unrecovered by the end of Period One. In an evidentiary hearing to establish Period Two rates, convened pursuant to Opinion No. 486-C,[400] shippers argued that the "at risk" statement in Opinion No. 486-A precluded Kern River from including in the rate base for Period Two rates any regulatory asset comprised of book depreciation expense for compressors and general plant that was recorded, but not recovered in rates, during Period One.[401]

In addition to filing a motion for clarification of Opinion No. 486-A, Kern River responded to the shippers' argument, in part, by filing revised tariff records to establish a periodic rate adjustment mechanism (PRA) to permit Kern River to recover, through annual adjustments to its firm service reservation charges, all deferred depreciation (*i.e.*, additions to its regulatory asset) associated with replacements of compressors and general plant through the end of Period One.[402] The October 29 Order accepted these records and suspended them for five months, subject to refund and to the FERC's ruling on Kern River's motion for clarification.[403] The FERC offered no views on the merits of Kern River's proposal but merely observed that it "raise[d] numerous issues under the Commission's regulations and policies governing periodic rate adjustment filings to recover a single cost item."[404]

By order issued on December 6, 2010, the FERC granted Kern River's motion for clarification in Docket No. RP04-274-000 and dismissed as moot Kern River's proposed PRA in Docket No. RP10-1406-000.[405] The FERC reviewed the context of the "at-risk" language of Opinion No. 486-A and noted the order's ensuing discussion approving regulatory asset treatment for deferred depreciation related to replacements of compressor engines and general plant.[406] The FERC reasoned that the "at-risk" language "simply states that, as with all deferred regulatory assets, Kern River is at risk whether it will actually recover those assets over the total period to which its levelized rate methodology applies."[407] The FERC held, therefore, that if, at the end of Period One, Kern River has recovered less cumulative regulatory depreciation for compressors and general plant than the book depreciation recorded on its books for such assets, it "may treat the difference as a regulatory asset and add it to the starting Period Two rate base for purposes of calculating the levelized Period Two rates."[408]

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399. "Period Two" refers to the period subsequent to expiration of the current firm shippers' service agreements; the duration of Period Two is an issue in the ongoing hearing the Commission established to determine Period Two rates. *See generally* 129 F.E.R.C. ¶ 61,240 at PP 258-261.

400. *Id*.

401. *December 6 Order, supra* note 395, at P 4.

402. *October 29 Order*, *supra* note 395, at P 1.

403. *Id.* at P 11.

404. *Id.* at P 10.

405. *December 6 Order* at P 1. The order also dismissed as moot a third response to the dispute by Kern River, an amendment to a previous compliance filing in Docket No. RP04-274-000 to revise the Period One compliance rates to include additions to the regulatory asset for replacements of compressors and general plant from the end of the test period in the proceeding through the end of Period One. *Id.* at PP 1, 6.

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

407. *Id.* at P 13.

408. *Id.* at P 12.

U. Reservation Charge Credits for Curtailment

In *Kern River Gas Transmission Co.,*[409] Kern River filed a request for rehearing or reconsideration of an order in which the Commission exercised its NGA section 5 authority to review Kern River's tariff.[410] The FERC directed Kern River to either file revisions to its tariff to provide reservation credits during periods of curtailment in a uniform way consistent with FERC policy or explain why it should not be required to do so.[411] In the August 6, 2010 order, the FERC found that Kern River had sufficiently shown that it "should not be required to have a uniform reservation charge credit provision" in those rate schedules that reflect the result of individually negotiated contracts.[412] However, the FERC rejected Kern River's argument as to the firm rate schedule and ordered Kern River to revise its firm Rate Schedule KRF-1 since it did "not contain any provision for granting shippers reservation charge credits during periods of curtailment."[413]

In *Natural Gas Supply Association,*[414] the Commission responded to a petition[415] asking the Commission to exercise its NGA section 5 authority to require all pipelines to review and revise their tariffs in accordance with FERC policy regarding reservation charge credit during periods of disruption of service.[416] The FERC declined to take such action but did restate its policy concerning reservation charge credits and urged pipelines to review their respective tariffs.[417] The FERC stated that "the amount of reservation charge credits a pipeline must give in the [case of a] non-*force majeure* [event] is measured by the amount of service" scheduled but not delivered and not by the "shipper's contractual entitlement for service."[418] Finally, the FERC directed its Division of Audits in the Office of Enforcement to include in future audits a review of whether "tariffs comply with the Commission's reservation charge crediting policy."[419]

In *Southern Natural Gas Co*.,[420] issued contemporaneously with *Natural Gas Supply Ass'n*, the Commission reviewed Southern Natural Gas's existing reservation charge credit provisions and found them contrary to Commission policy.[421] The Commission found that shippers should receive a full reservation credit for non-*force majeure* events and that provisions allocating the risk of

409. *Kern River Gas Transmission Company*, 132 F.E.R.C. ¶ 61,111 (2010) [hereinafter *August 6 Order*].

410. *Kern River Gas Transmission Company*, 129 F.E.R.C. ¶ 61,262 (2009) [hereinafter *December 18 Order*].

411. *August 6 Order, supra* note 409, at P 25.

412. The Commission found that Rate Schedules CH-1, UP-1, MO-1 and SH-1 did not need to be revised since they were the result of individually negotiated contracts. *Id.* at P 16.

413. *Id.* at P 17.

414. *Natural Gas Supply Ass'n*, 135 F.E.R.C. ¶ 61,055 (2011).

415. Petitioners consisted of the Natural Gas Supply Association, the American Forest and Paper Association, Inc., the American Public Gas Association, the Independent Petroleum Association of America, and the Process Gas Consumers Group. *Id.*

416. *Id.* at P 1.

417. *Id.* at P 28.

418. *Id.* at P 25.

419. *Id.* at P 28.

420. *Southern Natural Gas Co*., 135 F.E.R.C. ¶ 61,056 (2011).

421. *Id.* at PP 9, 11.

seasonal testing on shippers were unacceptable.[422] The Commission found it reasonable for the pipeline to use a seven-day historical average of usage as a substitute for use of actual scheduled amounts to determine the level of the shipper's reservation charge credits.[423] However, where a pipeline has not given advance notice, the reservation charge credit must be based on the scheduled amount because in that situation a shipper would not have had the opportunity to manipulate its schedules in order to game the system.[424]

In *Kern River Gas Transmission Co*.,[425] the FERC rejected proposed tariff sheets filed by Kern River in response to its Order in Docket No. RP10-160-001 since they did not comply with FERC policy regarding reservation charge credits.[426] The FERC rejected Kern River's approach, stating that Kern River had failed to comply with FERC policy by not utilizing one of the two approved methods for providing partial reservation charge credits in a force majeure situation: the Safe Harbor Method and the No-Profit method.[427] The Commission stated that when evaluating reservation charge credit provisions, the Commission would be guided by the policy that risks of any *force majeure*-induced service disruptions should be equitably shared and carefully balanced between the shippers and pipelines.[428] Kern River proposed to apply the same hybrid method to both *force majeure* and non-*force majeure* events, but FERC policy requires that pipelines provide full reservation charge credits for gas not delivered due to a non-*force majeure* event.[429] The Commission held that all "new contracts under Rate Schedule KRF-1 must follow [its policy regarding] reservation charge" credits, unless the parties agree to deviate and such agreements containing the material deviation are filed with the Commission for approval.[430]

V. Termination

In *Arena Energy, LP v. Sea Robin Pipeline Co*., the FERC dismissed a complaint alleging that Sea Robin had impermissibly terminated Arena's discounted rate contract for interruptible transmission service (ITS).[431] At the heart of the dispute was the question of whether the pipeline's termination rights were controlled by its *pro forma* service agreement and tariff or by the terms of the specific discounted service agreement between Arena and Sea Robin.[432]

Arena had two discounted rate contracts for ITS on Sea Robin.[433] Each contract specified a term of September 1, 2006 through August 31, 2011.[434]

422. *Id*. at P 21.
423. *Id*. at P 34.
424. *Id*.
425. *Kern River Gas Transmission Co.*, 135 F.E.R.C. ¶ 61,050 (2011).
426. *Id*. at PP 1, 23.
427. *Id.* at P 7.
428. *Id*. at P 17.
429. *Id.* at P 33.
430. *Id*.
431. *Arena Energy L.P. v. Sea Robin Pipeline Co.,* 133 F.E.R.C. ¶ 61,140 at P 1 (2010).
432. *Id.* at P 51.
433. *Id.* at P 4.
434. *Id.* at PP 4-6.

However, under the pipeline's *pro forma* rate schedule, the pipeline was expressly entitled to terminate service on the basis of shipper inactivity (*i.e.* inactivity lasting for two consecutive months or more), subject to a thirty-day notice.[435] As a result of Arena's inactivity under one contract, Sea Robin submitted notice to Arena on April 23, 2010 that it was terminating the contract effective May 31, 2010.[436] The termination notice did not apply to the other discounted service agreement under which Arena had shipped gas regularly.[437] Separately, Sea Robin received the FERC's approval to charge a Hurricane Recovery Surcharge for all of its customers, except those receiving service under existing discounted contracts.[438]

The FERC rejected Arena's arguments and dismissed the case, concluding that Sea Robin's termination notice was consistent with the *pro forma* tariff and service agreement.[439] Moreover, the FERC held that the service agreement should be read together in conjunction with the *pro forma* terms.[440] The FERC noted the tariff provision stating that any inconsistencies between the agreement and the rate schedule should be resolved in accordance with the terms of the rate schedule, which provided for early termination.[441] With respect to Arena's claim that termination was simply a stratagem for Sea Robin to impose the Hurricane Surcharge on existing discounted shippers, the FERC held that the surcharge was not an issue in this proceeding.[442]

III. INFRASTRUCTURE

A. Pipelines

In *XTO Energy Inc. v. Midcontinent Express Pipeline LLC*,[443] a gas producer and its affiliated gas marketer filed a complaint against Midcontinent Express Pipeline LLC (Midcontinent) alleging that Midcontinent had (1) improperly informed the FERC that its "new pipeline system [was] ready to be placed in service when the facilities were unable to operate at their full design capacity; and (2) charged improper rates for firm service during the first three months the . . . pipeline . . . as in service."[444] The allegations were based on the fact that Midcontinent did not receive a special permit and waiver "from the Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) to operate the pipeline at the contemplated maximum allowable operating pressure (MAOP)" until three months after the pipeline was put into service.[445] In the interim, Midcontinent operated the pipeline at a lower default regulatory standard so that it was only able to provide service using 88%

435. *Id.* at P 39.
436. *Id.* at P 8.
437. *Id.* at PP 7-8.
438. *Sea Robin Pipeline Co.*, 139 F.E.R.C. ¶ 63,009 at P 320 (2010).
439. 133 F.E.R.C. ¶ 61,140 at P 51.
440. *Id.*
441. *Id*. at P 53.
442. *Id*. at P 60.
443. *XTO Energy Inc. v. Midcontinent Express Pipeline LLC,* 132 F.E.R.C. ¶ 61,201 (2010).
444. *Id.* at P 1.
445. *Id.* at P 13.

of the design capacity but offered to provide firm shippers with a corresponding reduction of their reservation charges.[446]

The FERC dismissed the claims that Midcontinent had misrepresented the facts when it requested authorization to put its pipeline into service.[447] Although the FERC chastised Midcontinent for not informing the FERC about the status of its PHMSA authorization directly, this information had been posted on the pipeline's website.[448] What the FERC found to be determinative was that the certificate of public convenience and necessity required the pipeline to operate in compliance with DOT requirements and at all times Midcontinent operated in compliance with those requirements.[449] Therefore, the FERC found that it was appropriate for the pipeline to have been placed in service even though it was not able to satisfy all the MDQs of its firm shippers.[450] The FERC further found that the reduction in the reservation charges was a reasonable accommodation to the "inability to operate at full design pressure."[451] The FERC also rejected a contract claim that Midcontinent was required to continue to charge the interim rates for the initial phase of service until it received PHMSA approval to operate at a higher MAOP.[452] The FERC asserted primary jurisdiction to resolve a contract dispute because the issue was within its expertise and because of "a need for uniformity of interpretation" for the initial rate regime as implemented by the FERC certificate.[453]

In *South Coast Air Quality Management District v. FERC*, the U.S. Court of Appeals for the Ninth Circuit denied a petition for review of the FERC's order issuing a certificate authorizing North Baja Pipeline LLC to expand and modify its facilities to transport foreign-sourced LNG from Mexico into Southern California.[454] The petitioner had maintained that the FERC had not adequately considered the environmental impact of emissions resulting from the use of the gas, particularly the impact of nitrogen oxide emissions that result from burning gas with a higher heat content.[455] The court found that the FERC had adequately considered the emission impacts in its environmental impact statement when it "required [the pipeline to] only deliver gas that meets the strictest gas quality standards imposed by state regulatory agencies," specifically the California Public Utility Commission (CPUC), on downstream end-users and pipelines.[456] The court considered the FERC analysis to have been reasonably thorough, recognizing the uncertainty of the effects of introducing higher heat content gas, so that it fulfilled the NEPA requirement of informed agency action.[457] Further, the court considered the petitioner's arguments to be an impermissible collateral

446. *Id.* at P 14.
447. *Id*. at PP 22-26.
448. *Id.* at P 23.
449. *Id.*
450. *Id*. at P 25.
451. *Id*. at P 26.
452. *Id*. at PP 27-28.
453. *Id*. at P 30.
454. South Coast Air Quality Mgmt. Dist. v. FERC, 621 F.3d 1085 (9th Cir. 2010) (reviewing *North Baja Pipeline, LLC,* 121 F.E.R.C. ¶ 61,010 (2007), *reh'g denied*, 123 F.E.R.C. ¶ 61,073 (2008)).
455. *Id.* at 1093.
456. *Id*. at 1090.
457. *Id*. at 1094.

attack on the CPUC's gas quality standards.[458] The court also rejected petitioners' Clean Air Act claims, finding that the FERC's approval of the pipeline was a "but for" indirect cause of downstream emissions under EPA regulations but that the FERC has no continuing program responsibility over emissions.[459]

In *CAlifornians for Renewable Energy, Inc. (CARE) v. Williams Northwest Pipeline*, CARE, on behalf of itself and a member in Oregon, filed a complaint against Northwest Pipeline GP for the construction of a pig receiver, a 16-inch valve, fencing, a road, and a driveway within the footprint of an existing easement.[460] The complaint alleged that the pipeline had not given the landowner sufficient notice under section 157.203(d) of the blanket certificate regulations,[461] the activities were beyond the scope of those permitted by the existing easement,[462] the pipeline had engaged in deceptive activities in violation of NGA section 4A prohibiting market manipulation,[463] and that the landowner's informal complaint had been mishandled by the Commission's Enforcement Hotline.[464] The FERC denied the complaint.[465]

The FERC ruled that under the definitions in section 2.55 of its regulations[466] pig receivers are defined to be auxiliary installations which are excluded from the word "facilities" as used in NGA section 7 and are not subject to the certificate requirements.[467] Therefore, the pig receiver, surrounding fencing, driveway, and road providing access to the pig receiver were not constructed pursuant to the pipeline's blanket certificate so the landowner notifications of those regulations did not apply.[468] With respect to the claims that the construction and operation of those auxiliary installations were not authorized within the scope of the existing easement, the FERC noted that the pipeline's decision to proceed in reliance on "the existing easement agreement was at its own risk," but the FERC ruled that the proper forum for the interpretation of an easement is in a state or federal court.[469] With respect to the claims of a violation of the prohibition on market manipulation, the FERC ruled

458. *Id*. at 1098.

459. *Id*. at 1100-1101.

460. *CAlifornians for Renewable Energy, Inc. (CARE) v. Williams Nw. Pipeline,* 133 F.E.R.C. ¶ 61,194 at P 1 (2010), *reh'g denied*, 135 F.E.R.C. ¶ 61,158 (May 19, 2011).

461. 133 F.E.R.C. ¶ 61,194 at P 2.

462. *Id.* at P 22.

463. *Id.* at P 28.

464. *Id.* at P 31.

465. *Id.* at P 36.

466. 18.C.F.R. § 2.55 (2011).

467. 133 F.E.R.C. ¶ 61,194 at PP 13-15 (2010).

468. *Id.* at P 16.

469. *Id.* at PP 26-27. In the rehearing order, the FERC elaborated that it "expects [the pipeline] to possess the requisite property rights before it commences construction of . . . facilities," but this obligation comes from general real property and trespass laws not the NGA. The FERC explained that a pipeline is not required to have all the necessary property rights when it files a certificate application because it still may be negotiating with landowners. If those negotiations are unsuccessful, the FERC noted that its certificate authorization provides the pipeline with the opportunity to use eminent domain prior to construction but, responding to the complainant's argument, the FERC explained that a pipeline is not required to seek eminent domain prior to construction if it can acquire the property rights through a lease or purchase. 135 F.E.R.C. ¶ 61,158 at PP 14-16.

that the prohibition on fraudulent activity in section 1c.1 of its regulations does not apply because "none of [the pipeline's] actions or activities in this case concerned the 'purchase or sale' of natural gas or transportation service."[470] Finally, the Commission ratified the handling of the landowner's informal complaint by the Enforcement Hotline. In light of section 1b.21(a) of the regulations, which provides that the informal Hotline staff opinions "are not binding on the General Counsel or the Commission," the FERC ruled that a complainant "is not prejudiced by the [staff] policy" not to provide advice in writing, and a complainant has the right to file a formal complaint at any time if it is concerned the Hotline process causes delay.[471]

In *Murray Energy Corp. v. FERC*, the owner and operator of an underground longwall coal mine concerned about the potential safety hazards posed to a pipeline built above mining that causes the surface to subside, sought D.C. Circuit review of the FERC's orders authorizing Rockies Express Pipeline LLC (REX) to begin the construction of its REX-East pipeline above the coal mine.[472] The orders under review were the delegated order issued by a branch chief in the Office of Energy Projects (OEP) approving the REX construction plan, as consistent with the conditions of the FERC certificate order, and the Commission rehearing order affirming the delegated order.[473] The Petitioner argued that the delegated order was outside the scope of the staff's delegated authority because section 375.308 of the Commission's regulations[474] only permits the OEP Director to further delegate the Director's authority on noncontroversial and routine requests whereas the siting, construction, and operation of the REX-East pipeline did not fit within that category.[475] The Petitioner also argued that the branch chief who issued the delegated order was not an appropriate designee for the Director's delegated authority within the meaning of section 375.301(b) of the Commission's regulations.[476] The D.C. Circuit ruled these arguments failed because the FERC rehearing order had ratified the staff sub-delegation practice and expressly adopted the staff action as the Commission's own.[477]

The petitioner also argued that REX had not fulfilled the condition of its certificate that required the pipeline to collaborate with the Petitioner to develop "a construction plan that maintain[ed] pipeline integrity . . . without impeding . . . mining activities," and if that collaboration "did not culminate in a plan," then to find "an alternative route that avoids [the] coal reserves."[478] Since the record showed numerous communications between the parties and that REX had submitted a plan to achieve the required objectives, the court ruled that "absent evidence of bad faith on REX's part, . . . [it] was reluctant to read [the

470. *CAlifornians for Renewable Energy, Inc.*, 133 F.E.R.C. ¶ 61,194 at P 29 (2010).

471. *Id.* at PP 35-36.

472. Murray Energy Corp. v. FERC, 623 F.3d 231 (D.C. Cir. 2011).

473. Letter Order, FERC Docket No. CP07-208-000 (Mar. 19, 2009), *reh'g granted in part and denied in part*, *Rockies Express Pipeine, LLC,* 128 F.E.R.C. ¶ 61,045 (2009).

474. 18 C.F.R. § 375.308 (2011).

475. *Murray Energy Corp.*, 629 F.3d at 236.

476. *Id.*; *see also* 18 C.F.R. § 375.301(b).

477. *Murray Energy Corp.*, 629 F.3d at 236.

478. *Id.* (internal quotations omitted).

requirement to collaborate] as requiring anything more."[479] The Petitioner's final claims were that the REX "construction plan failed to ensure the safety of the pipeline" over the mine.[480] The court found that substantial evidence supported the FERC's approval of the REX construction plan, the decision was neither arbitrary nor capricious, and the petitioner's arguments relied on strained or unreasonable interpretations of relevant provisions.[481] As a result, the court denied the petition for review.[482]

In *Ruby Pipeline, L.L.C.*, the Summit Lake Paiute Tribe sought a stay of construction of a portion of the Ruby Pipeline project in northwest Nevada that runs through federal, state, and private lands, "which the Tribe maintain[ed] it [had] intentionally worked to keep undeveloped because of the . . . spiritual significance [of the area] for tribal members."[483] The FERC denied the stay noting that the Tribe had sought rehearing of the FERC order issuing the certificate and had filed a petition for review of the FERC orders.[484] The FERC stated that under its long-standing standards for evaluating a request for a stay, *i.e.,* "(1) whether the party requesting the stay will suffer irreparable injury without a stay; (2) whether issuing the stay may substantially harm other parties; and (3) whether a stay is in the public interest," the FERC's "general policy is to refrain from granting stays in order to assure definiteness and finality to [its] proceedings."[485] The FERC concluded that the Tribe did not meet the standards justifying a stay.[486]

On May 17, 2011, *Denali – The Alaska Gas Pipeline LLC* (Denali), one of the two firms considering the development project to bring natural gas from Alaska's North Slope to the continental United States, filed a letter with the FERC withdrawing its request to use the pre-filing process for review of its project.[487] As noted in the letter, Denali "conducted [an] open season in accord[ance] with the Commission's rules . . . [and] conducted negotiations to reach binding precedent agreements with . . . prospective shippers that submitted open season bids . . . [but had] not received the customer support needed to continue [with] the project."[488] Therefore, Denali was terminating the project.

B. LNG Projects

In *Cameron LNG, LLC*, the FERC authorized Cameron LNG, LLC (Cameron LNG) to operate its LNG import terminal in Cameron Parish, Louisiana "for the additional purpose of exporting LNG which [had] already been imported into the United States."[489] Cameron was previously authorized to

479. *Id*. at 237.
480. *Id*.
481. *Id*. at 238-239.
482. *Id*. at 241.
483. *Ruby Pipeline, L.L.C.,* 134 F.E.R.C. ¶ 61,020 at PP 1, 10 (2011).
484. *Id.* at PP 5-6.
485. *Id*. at P 15.
486. *Id.* at P 17.
487. Letter from J. Scott Jepson, Vice President of Bus. Servs, Denali – The Alaska Gas Pipeline LLC, to Kimberly D. Bose, Sec'y, FERC at 1, FERC Docket No. PF08-26-000 (May 17, 2011).
488. *Id.*
489. *Cameron LNG, LLC,* 134 F.E.R.C. ¶ 61,049 (2011).

construct and operate the LNG import terminal, which was placed into service in July 2009.[490] In September 2010, Cameron applied for permission to also operate its terminal to export LNG under section 3 of the NGA.[491] Cameron LNG stated that its proposal will provide its customers with the ability to export previously imported LNG to a foreign market.[492] No new facilities or modifications were proposed.[493] The FERC found that approval of the project as proposed and conditioned in the order "will not constitute a major federal action significantly affecting the quality of the human environment."[494]

In *Southern LNG, Inc.*, the FERC addressed a rehearing application filed by Marathon LNG Marketing LLC (Marathon) regarding Southern LNG Inc.'s (Southern LNG) filing with the FERC of "a negotiated rate agreement between Southern LNG and BG LNG for . . . service under [Southern LNG's existing] Rate Schedule LNG-1" and Southern LNG's compliance filing to implement the negotiated agreement.[495] "[T]he negotiated rate agreement [permits] BG LNG to use expanded docking facilities . . . . to bring in larger size ships to the Elba Island [LNG import] terminal."[496] The dock facilities were completed and available for use prior to the completion of certain vaporization and storage tank facilities, all of which are part of the Elba III expansion, which the FERC approved in September 2007.[497] Since Southern LNG "could not provide . . . service under [its new] Rate Schedule LNG-3" until completion of the additional facilities at the Elba Island LNG terminal, the parties agreed to an "additional reservation charge in the negotiated rate agreement above the maximum LNG-1 rate [to pay] for BG LNG's use of the expanded docking facilities."[498] Marathon argued that the FERC erred in accepting the negotiated rate agreement.[499] The FERC concluded "that Southern LNG's negotiated rate agreement with BG LNG is a just and reasonable method [to allow] BG LNG to use the expanded dock facilities . . . under its existing [LNG-1] contract."[500] The Commission found that the "negotiated rate agreement permits BG LNG to make more efficient use of its existing LNG-1 service agreement by bringing in larger 'Q-Max' size ships at the Elba Island terminal [until] the in-service date of the remaining Elba III facilities necessary to providing LNG-3 service."[501]

In *Dominion Cove Point LNG, LP* (Cove Point), the FERC rejected proposed tariff changes that would, among other things, allow Cove Point to issue an Operational Flow Order (OFO) requiring the importation of LNG for operational purposes.[502] The tariff revisions were prompted by a decrease in

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490. *Cameron LNG, LLC*, 104 F.E.R.C. ¶ 61,269 (2003); *Cameron LNG, LLC*, 118 F.E.R.C. ¶ 61,019 (2007).

491. 134 F.E.R.C. ¶ 61,049 at P 1.

492. *Id.* at P 9.

493. *Id.*

494. *Id.* at P 12.

495. *Southern LNG, Inc.,* 134 F.E.R.C. ¶ 61,237 at PP 1-2, 7 (2011).

496. *Id.* at P 7.

497. *Southern LNG Inc.,* 120 F.E.R.C. ¶ 61,258 (2007), *reh'g denied* 122 F.E.R.C. ¶ 61,137 (2008).

498. 134 F.E.R.C. ¶ 61,237 at P 32.

499. *Id.* at P 29.

500. *Id.* at P 31.

501. *Id.*

502. *Dominion Cove Point LNG, LP*, 136 F.E.R.C. ¶ 61,059 at P 3 (2011).

LNG shipments to Cove Point, threatening the facility's ability to maintain a minimum level of LNG inventory to protect the operational integrity of the cryogenic portions of its system.[503] Statoil Natural Gas, BP Energy Company, Process Gas Consumers Group, Shell NA LNG, and the Independent Petroleum Association of America protested the revised tariff provisions.[504] The FERC rejected Cove Point's OFO proposal but clarified that Cove Point has existing tariff authority to make operational purchases of LNG.[505] The FERC noted that an operational purchase of LNG to keep its cryogenic facilities cooled to the requisite temperature would be a cost of providing jurisdictional service and although Cove Point does not have a cost recovery mechanism in its tariff,[506] Cove Point could make a limited NGA section 4 filing to include a cost recovery mechanism in its tariff.[507] The FERC suspended implementation of all other tariff revisions and ordered a technical conference to explore issues raised in the filing.[508]

503. *Id.* at P 1.

504. *Dominion Cove Point LNG, LP*, 135 F.E.R.C. ¶ 61,261 at P 6 (2011).

505. *Id.* at P 35.

506. *Id*. at P 41.

507. *Id.* at P 42.

508. *Id*. at P 43.

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