REPORT OF THE NATURAL GAS REGULATION COMMITTEE

This report summarizes decisions and policy developments that have occurred in the area of natural gas regulation. The timeframe covered by this report is July 1, 2007 to June 30, 2008.[1]

1. The Natural Gas Regulation Committee wishes to acknowledge the support of the full Committee in producing this report, and in addition, to recognize specific Committee members who made particular contributions to this report. Those members are: Lawrence G. Acker, Kenneth M. Albert, Christopher J. Barr, Julie Baumgarten, Glenn S. Benson, Anne E. Bomar, Andrea Jean Chambers, Mark G. Cook, Bray Dohrwardt , Joseph H. Fagan, Russell A. Feingold, Kirstin R. Gibbs, Marvin T. Griff, Christopher Gulick, Patrick J. Hester, Christopher John, Thomas J. Knapp, Elizabeth B. Kohlhausen, Kenneth T. Maloney, Everard A. Marseglia Jr., Henry S. May Jr., Letitia W. McKoy, Paula K. Motzel, Diane S. Neal, Adina Owen, Delia Patterson, Jeffrey M. Petrash, Robert C. Platt, Mark M. Rabuano, Randall S. Rich, Richard G. Smead, Andrew K. Soto, Channing D. Strother Jr., Kevin M. Sweeney, Branko Terzic, Michael J. Thompson, Sarah E. Tomalty, Peter I. Trombley, Dena Eve Wiggins.

I. RULEMAKING ACTIONS

A. Reporting Requirements for Pipelines

On March 20, 2008, the Federal Energy Regulatory Commission (FERC) issued Order No. 710[2] revising the financial forms, statements, and reports required from interstate natural gas companies contained in the FERC Form Nos. 2, 2-A, and 3-Q. The FERC described the enhanced forms as better reflecting the "current market and cost information" needed by the FERC in its regulatory oversight of pipelines' rates and terms of service. The FERC believes Order No. 710 will affect the reporting obligations of 118 companies within the FERC's jurisdiction.

The FERC has experienced a decline in Natural Gas Act (NGA)[3] section four rate filings since Order No. 636 and the elimination of the triennial restatement of rate filings. The FERC's research shows that "as many as 15 major and 20 nonmajor gas pipelines have not filed a [NGA] section 4" rate case in more than a decade."[4] In an era of reduced NGA section four tariff filings, the FERC relies on NGA section four complaints filed by pipeline customers or state public utility FERCs as the method for determining when it needs to review a pipeline company's rates outside of an NGA section four proceeding.[5] NGA section four complaints often rely on FERC Forms 2, 2-A, and 3-Q financial data to support the complaint and the need for a rate investigation.[6] The FERC, therefore, intends the enhanced FERC forms to ensure that pipeline customers have the financial data needed to evaluate the pipeline's rates and, if appropriate, support a NGA section four complaint.

2. Final Rulemaking, *Revisions to Forms, Statements, and Reporting Requirements for Natural Gas Pipelines*, 70 Fed. Reg. 19,389 (2008) (to be codified at 18 C.F.R. pt. 158 and 260); *See also* F.E.R.C. Press Release, FERC Adds Transparency, Clarity to Gas Company Financial Reporting Requirements, R-08-21 (issued Mar. 20, 2008).

3. 122 F.E.R.C. ¶ 61,262.

4. *Id.* at pp. 19,389-90

5. FERC also may institute a NGA § 5 investigation on its own motion.

6. 73 Fed. Reg. 19,389 -90.

The FERC describes the rules adopted by Order No. 710 as enhancing the ability of shippers to assess the justness and reasonableness of pipeline rates.[7] In particular, according to the FERC, the rules adopted in Order No. 710 "“will require companies to submit additional revenue information related to the disposition of shipper-supplied gas, affiliate transactions, rate treatment for new facilities, discounted and negotiated rate services, deferred income tax and state tax issues and regulatory assets and liabilities.”“[8]

Order No. 710 revises FERC Form No. 2 (Annual Report for Major Gas Companies), FERC Form No. 2A (Annual Report for Non-Major Gas Companies), and FERC Form 3-Q (Quarterly Financial Report of Electric Utilities, Licensees, and Natural Gas Companies), and eliminates FERC Form No. 11 (Natural Gas Pipeline Company Quarterly Statement of Monthly Data).[9]

New schedules in FERC Forms 2, 2-A, and 3-Q require the pipeline to report:

> (1) [t]he difference between the volume of gas received from shippers and the volume of gas consumed in pipeline operations each month; (2) the disposition of any excess and the accounting recognition given to such disposition, including the basis of valuing the gas and the specific accounts charged or credited; and (3) the source of gas used to meet any deficiency, including the accounting basis of the gas and the specific account(s) charged or credited.[10]

Previously, FERC Forms 2 and 2-A required filers to report “Gas Operating Revenues” [11] on an aggregate basis as a single entry. Under Order No. 710, pipelines now must report sales by specific account (residential, commercial and industrial, public authorities, sales for resale, and interdepartmental).[12] In addition, the following types of revenues must be separately reported on the new schedules in FERC Forms 2 and 2-A:

> (1) [c]ommissions on sale or distribution of gas of others; (2) compensation for minor or incidental services provided for others; (3) profit or loss on sale of material and supplies not ordinarily purchased for resale; (4) sales of steam, water, or electricity, including sales or transfers to other departments; (5) miscellaneous royalties; (6) revenues from dehydration and other processing of gas of others except as provided for in the instructions to Account 495; (7) revenues for rights and/or benefits received from others which are realized through research, development, and demonstration ventures; (8) gains on settlements of imbalances receivable and payables; (9) revenues from penalties earned pursuant to tariff provisions, including penalties associated with cash-out settlements; and (10) revenues from shipper-supplied gas.[13]

FERC Forms 2 and 2-A historically did not require any reporting of affiliate transactions. The FERC believes that disclosure of affiliate transactions is needed to prevent cross-subsidization between regulated and unregulated

7. *Id.*at 19,390.

8. Federal Energy Regulatory FERC, *News Release: FERC adds transparency, clarity to gas company financial reporting requirements* (March 20, 2008), http://www.ferc.gov/news/news-releases/2008/2008-1/03-20-08-M-2.asp.

9. 73 Fed. Reg. 19,391.

10. *Id.*

11. *Id.* at 19,392.

12. *Id.*

13. *Id.*

companies. New schedules to FERC Forms 2 and 2-A require filers to report affiliate transactions. Those new schedules include: "(1) [a] description of the good or service transacted; (2) the name of the associated (affiliated) company; (3) the FERC account charged or credited; and (4) the amount charged or credited."[14]

Order No. 710 also adopted several other changes to FERC Forms 2, 2-A, and 3-Q that address the pipeline's rate treatment for new projects (*i.e.*, rolled-in or incremental rates), discounted and negotiated rate services, deferred income taxes, state income tax expense, regulatory assets and liabilities, employee pensions and benefits, source of capital structure, and source of return on equity figures.[15]

On June 20, 2008, the FERC issued Order No. 710-A[16] granting in part and denying in part requests for rehearing and clarifying Order No. 710. In particular, the FERC reinstated a minimum reporting threshold for the "Other Gas Revenues" to be reported on page 308 of FERC Form Nos. 2 and 2-A and clarified that the reporting requirements for the ten categories of discrete miscellaneous revenues listed thereon be limited to transactions with annual revenues of 250,000 dollars or greater.[17]

B. Standards of Conduct

On March 21, 2008, the FERC issued a Notice of Proposed Rulemaking (NOPR) seeking comments on proposed reforms to its Standards of Conduct for natural gas pipelines and electric transmission providers.[18] The March 21 NOPR replaces the NOPR issued in January 2007, after the United States Court of Appeals for the D.C. Circuit overturned the Standards of Conduct as applied to natural gas pipelines.[19] The FERC stated the new NOPR was necessary to correct "fatal flaws" in the current standards, which it described as overly broad, complex and difficult to understand.[20]

While the FERC proposes to abandon the "corporate separation" approach established in Order No. 2004 and to restore the "functional" approach that existed in earlier versions of the Standards of Conduct under Order Nos. 497 and 889, it also proposes to retain large elements of the current rules.[21] Under the NOPR, the standards would be restructured into three per se rules: the independent functioning rule, the no-conduit rule, and the transparency rule. Failure to comply with these per se rules would automatically establish a

14. *Id.*

15. *Id.* at 19,392-95.

16. *Revisions to Forms, Statements, and Reporting Requirements for Natural Gas Pipelines*, 123 F.E.R.C. ¶ 61,278 (2008).

17. *Id.* at P 7.

18. Notice of Proposed Rulemaking, *Standards of Conduct for Transmission Providers*, 73 Fed. Reg. 16,228 (2008) (to be codified at 18 C.F.R. pt. 358).

19. *Id.*

20. *Id.*at 16,229

21. *Id.* at 16,230.

sanctionable violation, although the FERC would retain the ability to investigate and determine whether specific conduct is unduly discriminatory.[22]

1. Independent Functioning Rule

The NOPR proposes to carry forward its independent functioning rule. However, the FERC proposes to abandon the corporate separation approach that existed under Order No. 2004 standards and instead adopt an employee functional approach. Under the FERC's proposal, "transmission function employees" must operate independently of "marketing function employees" (whether employed within the corporate structure of the transmission provider or by an affiliate of the transmission provider).[23] The NOPR creates a "de minimis" exception so that only those officers and employees who spend more than a de minimis amount of time engaged in those functions would be classified as "transmission function employees" or "marketing function employees."[24] In addition, supervisors, officers, or directors who are not actively and personally engaged in transmission functions or marketing functions, will not be considered "transmission function employees" or "marketing function employees."[25]

Exceptions to the Independent Functioning Rule are provided for: (i) bundled retail sales, (ii) incidental operational gas purchases and sales, (iii) gas sales solely from the provider's own production or own gathering or processing facilities, and (iv) intrastate pipeline and LDC on-system sales.[26]

2. No-Conduit Rule

The NOPR also proposes to continue the prohibition against the disclosure of transmission system information to marketing function employees.[27] However, the NOPR proposes to expand this rule to prohibit all employees (not just transmission function employees) from disclosing transmission information to marketing function employees and to prohibit marketing function employees from receiving transmission system information.[28] In addition, the NOPR proposes to prohibit transmission providers from using a conduit to pass restricted information to marketing function employees.[29]

3. Transparency Rule

The NOPR also proposes to maintain a transparency requirement. Under this rule, a transmission provider must post any inadvertent disclosure of non-public information on Open Access Same-time Information System (OASIS)[30] or its internet website (if an unauthorized disclosure includes non-public transmission customer information, the posting need only reflect the fact that

22. *Id*. at 16,231.
23. *Id.* at 16,232.
24. *Id.* at 16,233-34.
25. *Id.*
26. *Id.*
27. *Id*. at 16,235.
28. *Id.*
29. *Id.*
30. *Id*. at 16,235.

information was disclosed; the actual information that was disclosed need not be posted).[31] In addition, contemporaneous records must be made of conversations between transmission function employees and marketing function employees (and such records must be maintained for FERC review).[32]

C. Capacity Release

On June 19, 2008, the FERC issued Order No. 712, which revised its Part 284 regulations governing the release of firm capacity on interstate natural gas pipelines in several ways.[33] First, the FERC removed, "on a permanent basis, the rate ceiling on capacity release transactions of one year or less."[34] Second, the FERC modified its "regulations to facilitate the use of asset management arrangements (AMAs), under which a capacity holder releases some or all of its pipeline capacity to an asset manager who agrees to either purchase gas from, or supply the gas needs of, the capacity holder."[35] Third, the FERC clarified that its prohibition against tying arrangements does not apply to conditions associated with the sale and/or purchase of gas inventory held in storage that may be required by releasors of firm storage capacity.[36] Fourth, the FERC modified its capacity release regulations to facilitate retail open access programs by exempting capacity releases made under state-approved retail access programs from the prohibition against tying arrangements and the bidding requirements of section 284.8 "of the FERC's regulations."[37]

With respect to the removal of the price cap, the FERC determined that it would improve shipper options and market efficiency, particularly during peak periods, by allowing the prices of short term capacity release transactions to reflect short term variations in the market value of that capacity.[38] At the same time, the FERC found that rates for short term capacity would remain just and reasonable based on a review of data that showed that the value of such capacity only exceeded the ceiling price during brief periods of constraint.[39] Moreover, the FERC stated that it was not relying solely on the market to keep prices just and reasonable because it was maintaining the rate cap on pipeline firm and non-firm services.[40] Finally, the FERC determined that certain informational posting requirements that it would adopt would facilitate transparency and the filing of complaints, if necessary.[41]

Turning to AMAs, the FERC found that these arrangements are in the public interest because they are beneficial to numerous market participants and

31. *Id.* at 16,235-36.

32. *Id.* at 16,236.

33. Final Rule, *Promotion of a More Efficient Capacity Release Program*, 73 Fed. Reg. 37,058 (2008) (to be codified 18 C.F.R. 284).

34. *Id.*

35. *Id.* at 37,059.

36. *Id*.

37. *Id.*

38. *Id.* at 37,061.

39. *Id.*

40. *Id.*

41. *Id.*

the market in general.[42] In order to facilitate AMAs, the FERC exempted such arrangements from the prohibition against tying so that a "releasing shipper in a pre-arranged release [could] require that the replacement shipper agree to supply the releasing shipper's gas requirements and take assignment of the releasing shipper's gas supply contracts, as well as' release [the shipper's] transportation capacity."[43] The FERC also exempted pre-arranged releases necessary to implement AMAs from the bidding requirements of section 284.8 of the 'FERC's regulation. The FERC further clarified that the exemption from bidding for AMAs applies to all releases to an asset manager, including those made for a short term AMA.[44]

The Final Rule defined an AMA that qualified for the tying and bidding exemptions as follows:

> any pre-arranged release that contains a condition that the releasing shipper may, on any day during a minimum period of five months out of each twelve-month period of the release, call upon the replacement shipper to (i) deliver to the releasing shipper a volume of gas to one-hundred percent of the daily contract demand of the released transportation capacity or (ii) purchase a volume of gas up to the daily contract demand of the released transportation capacity. If the capacity release is for a period of less than one year, the asset manager's delivery or purchase obligation described in the previous sentence must apply for the lesser of five months or the term of the release. If the capacity release is a release of storage capacity, the asset manager's delivery or purchase obligation need only be one-hundred percent of the daily contract demand under the release for storage withdrawals or injections, as applicable.[45]

The FERC further clarified that the price ceiling applicable to long term capacity releases does not apply to any consideration provided by an asset manager to a releasing shipper as part of an AMA.[46] The FERC also granted an exemption from the prohibition against buy/sell transactions in the context of AMAs in order to permit an asset manager to engage in a buy/sell to facilitate the delivery of gas supplies to a releasing shipper.[47] However, the FERC declined to permit shippers to include Part 157 capacity in AMAs.[48]

With respect to the tying of storage capacity and inventory, the FERC clarified that firm storage shippers wishing to release their storage capacity may include conditions concerning the sale and/or repurchase of gas in storage inventory both inside and outside the AMA context. Specifically, this exception to the tying rule allows a shipper releasing storage capacity to require the replacement shipper to: (i) take title to any gas in the released storage capacity at the time the release takes effect, and/or (ii) return the storage capacity to the releasing shipper at the end of the release with a specified amount of gas in storage.[49]

42. *Id.*
43. *Id.*
44. *Id.* at 37,062.
45. 18 C.F.R. § 284.8 (2008).
46. 73 Fed. Reg. 37,063.
47. *Id.* at 37,077.
48. *Id.* at 37,088.
49. *Id.* at 37,089.

Finally, Order 712 clarified that the prohibition against tying does not apply to releases by a local distribution company to a marketer that agrees to sell gas to the LDC's retail customers under a state-approved retail choice program. In order to qualify for the exemption, the released capacity must be used by the replacement shipper to provide the gas supply requirements of retail customers pursuant to a retail access program approved by the state agency with jurisdiction over the LDC that provides local delivery service to such retail customers.[50]

D. Transparency

On December 20, 2007, the FERC took two steps intended to improve transparency in the wholesale markets for physical natural gas. Order No. 704[51] adopted final rules requiring certain natural gas market participants to report to the FERC, on an annual basis, certain information regarding: (1.) their wholesale, physical natural gas transactions; (2.) their reporting of transactions to price index publishers; and (3.) their blanket certificate status. In a separate NOPR, the FERC proposed to require interstate and certain "major non-interstate pipelines" to post capacity, daily scheduled flow information, and daily actual flow information.[52]

1. Order No. 704

The final rules adopted in Order No. 704 for Parts 260, 284, and 385 of the FERC's regulations require buyers and sellers of more than a de minimis volume of natural gas to report the aggregated volumes of relevant transactions in a new FERC Form No. 552 on an annual basis. In particular, any buyer or seller of more than 2.2 million MMBTUs (Million British Thermal Units) of physical natural gas during a calendar year must report the aggregate volumes of the relevant transactions to the FERC. The annual report is due on May first of the year following the calendar year in which the natural gas was purchased or sold. The new FERC Form No. 552 requires filers to provide the following information:

> a. The total volume of sales and purchases for the previous calendar year;
> b. The volumes of transactions that were priced at fixed prices for next-day delivery and were reportable to price index publishers;
> c. The volume of transactions priced by reference to next-day gas price indices;
> d. The volume of transactions that were priced at fixed prices for next-month delivery and were reportable to price index publishers; and
> e. The volume of transactions priced by reference to next-month gas price indices.[53]

The FERC held technical conferences on April 22, 2008, and May 19, 2008, to discuss issues regarding preparation and submission of the new annual reporting form. The FERC staff distributed a presentation providing answers to

50. *Id.* at 37,090.

51. Final Rulemaking, *Transparency Provisions of Section 23 of the Natural Gas Act*, 73 Fed. Reg. 1,014 (2008) (to be codified at 18 C.F.R. pts. 260, 282 and 385).

52. Notice of Proposed Rulemaking, *Pipeline Posting Requirements Under Section 23 of the Natural Gas Act*, F.E.R.C. STATS & REGS. ¶ 32,626, 73 Fed. Reg. 1,116 (2008).

53. Order No. 704, *Transparenty Provisions of Section 23 of the Natural Gas Act*, [Regs. Preambles 2007-2008] F.E.R.C. STATS. & REGS., ¶ 31,260 at P 14 (2008) (codified at 18 CFR pt. 260, 285, and 385).

questions regarding new Form No. 552 that had been submitted by industry participants prior to the workshops.[54]

2. NOPR – Pipeline Capacity and Flow Posting Requirements

The FERC proposes to modify Part 284 of its regulations to require pipelines (including some intrastate pipelines) to post capacity and daily flow information on their company websites.[55] The FERC believes the proposed reporting requirement will provide it with the information it needs to track daily flows of natural gas throughout the United States.[56]

The FERC proposes to apply the new reporting requirements to interstate pipelines and "major non-interstate pipelines."[57] The FERC defines "major non-interstate pipelines" as all pipelines that flow more than ten Billion cubic feet (Bcf) of natural gas per year (measured as a rolling three calendar year average) except for pipelines that fall entirely upstream of a processing plant and pipelines that deliver more than ninety-five percent of their gas volumes directly to end users.[58]

Under the proposed rules, interstate pipelines must post information on actual flowing volumes at receipt points, on the mainline, at delivery points, and in storage fields within twenty-four hours from the close of the gas day on which the gas flowed.[59] Similarly, major non-interstate pipelines must post within twenty-four hours from the close of the gas day: (1.) the capacity of major points and mainline segments, (2.) the amount scheduled on those major points and mainline segments, and (3.) the actual gas flow volumes at those major points and mainline segments.[60]

E. Revisions to Landowner Notification and Blanket Certificate Regulations

On October 18, 2007, the FERC issued Order No. 700, which modifies the conditions for natural gas projects undertaken pursuant to blanket certificate authority.[61] First, the Final Rule amends Part 157 of the FERC's regulations by expanding landowner notification requirements[62] "to "enhance public participation in the [FERC's] consideration of proposed projects...."[63] Second, the new regulation requires sponsors to submit noise surveys for blanket projects that include compressor facilities. By this change, the FERC "ensure[s] that [compressor projects] completed under blanket certificate authority will not have

54. FERC TRANSACTION REPORT FERC FORM NO. 552: ANNUAL REPORT OF NATURAL GAS TRANSACTIONS, FERC, www.ferc.gov/docs-filing/eforms/form-552/form-552.pdf (last visited Sept. 10, 2008).

55. 73 Fed. Reg. 1,116.

56. *Id.*

57. *Id.*

58. *Id.* at 1,116-17.

59. *Id.* at 1,122.

60. *Id.*

61. Final Rulemaking, *Revisions to Landowner Notification and Blanket Certificate Regulations*, 72 Fed. Reg. 59,939 (2007) (to be codified at 18 C.F.R. pt. 157); *see also,* Notice of Proposed Rulemaking, *Revisions to Landowner Notification and Blanket Certificate Regulations*, 72 Fed. Reg. 35,669 (2007).

62. 72 Fed. Reg. at 59,939.

63. *Id.*

a significant adverse environmental impact[]...."[64] Order No. 700 is the first adjustment of the Part 157 blanket certificate program, since the FERC expanded the range of projects eligible for construction under blanket authority in 2006.[65]

1. Landowner Notification

Prior to Order No. 700, companies planning to construct or modify compressor, or liquefied natural gas (LNG) facilities, were required to notify all landowners *whose property contains a residence* within one-half mile of the project site, before beginning construction.[66] Order No. 700 removes the residence qualification. As a result, sponsors are to notify *all* landowners within one-half mile of the planned project site. The FERC explained that such notice should enable stakeholders to "...raise land use issues, including existing non-residential uses as well as planned future uses of undeveloped land."[67]"

2. Noise Surveys

Adoption of the FERC's blanket certificate program was premised on a 1981 Environmental Assessment, which adopted a noise-related standard designated by the United States Environmental Projection Agency. That assessment indicated that construction undertaken through blanket certificate authority should not increase ambient noise levels at nearby noise-sensitive areas (or NSAs) above an average day-night sound level (L_{dn}) of fifty-five decibels (dBA).[68] The noise survey requirement will serve to document that project sponsors have complied with the premise of the blanket certificate authorization, by meeting established noise level limits (an L_{dn} of fifty-five dBA at NSAs, when operating at full load).[69]

The FERC clarified that it will review the composite noise level from a compressor station's new and existing facilities, operating at full load, to evaluate whether a modification has met blanket certificate standards. An "addition or modification to an existing compressor station that is operating at or below an L_{dn} of 55 dBA at NSAs must not cause overall noise attributable to the station to exceed an L_{dn} of 55 dBA at NSAs."[70] Where an existing station already operates above these limits, an addition or modification undertaken pursuant to blanket authority, must not cause the overall station noise to increase at any NSAs.[71]

To demonstrate its compliance with noise level limits, the blanket project sponsor must submit a noise survey within sixty days of placing the new or modified compression facility in service, measuring overall noise attributable to the post-construction facility, operating at full load. Where the measured post-

64. *Id.*

65. Final Rulemaking, *Revisions to the Blanket Certificate Regulations and Clarification Regarding Rates*, 71 Fed. Reg. 63,680 (2006) (to be codified at 18 C.F.R. pt. 157).

66. 72 Fed. Reg. at 59,939 (emphasis added).

67. *Id*.

68. *Id.* at 59,940.

69. *Id.*

70. *Id.*

71. *Id.*

construction noise exceeds applicable limits at NSAs, the project sponsor has one year from the facility in-service date to complete noise mitigation measures. Within sixty days of remediation, the company must file a second survey to demonstrate that the facility, as modified, is compliant with applicable noise limits.[72]

F. Fuel Cost Recovery

On September twentieth, the FERC issued a Notice of Inquiry (NOI) seeking comments on its policy regarding the in-kind recovery of fuel and lost and unaccounted for gas by natural gas companies.[73] The FERC stated that in response to concerns expressed by pipeline customers that fuel requirements are excessive and provide pipelines with significant profits, a review of its policies is warranted.[74] The FERC sought comments on whether its policies regarding the in-kind recovery of fuel and lost and unaccounted for gas should be modified, both for the purpose of providing pipelines a greater incentive to reduce their fuel use and for the purpose of minimizing pipeline over-recoveries of costs. In particular, the FERC requested comments on the following questions: (1) whether it should continue to allow recovery of pipeline fuel costs through fixed fuel retention percentages; (2) whether it should mandate that all pipelines must have a tracker mechanism for the recovery of fuel; (3) whether if it required pipelines to use a tracker, it should require a true-up mechanism; and (4) whether it should retain its current policy.[75]

II. ENFORCEMENT ACTIONS

The FERC's Office of Enforcement (OE) continues to assess civil penalties for violations related to the FERC's "core" natural gas policies and regulations, including for violations of its shipper-must-have-title requirement, buy/sell prohibition and capacity release posting and bidding requirements. During the past twelve months, there were four new settlements resulting in civil penalties that ranged from 300,000 dollars to 7,000,000 dollars and for the most serious offenses, parties were required to disgorge profits and provide periodic compliance reports to the FERC.

In November 2007, the FERC also offered general guidance regarding OE's activities by publishing its "Report on Enforcement"[76] and holding a public conference on enforcement.[77] The Report and the accompanying Statement by Chairman Kelliher provide data about the FERC's recent enforcement activities and useful information concerning the FERC's enforcement philosophy and approach. For example, Chairman Kelliher stated that "the most important mitigating factor in determining the size of [the] civil penalty should be the

72. *Id.*.

73. Notice of Inquiry, *Fuel Retention Practices of Natural Gas Companies*, 72 Fed. Reg. 55,762 (2007).

74. *Id.* at 55,673.

75. *Id.*

76. Staff Report on Enforcement, Docket No. AD07-13-000, (FERC issued Nov. 14, 2007).

77. Enforcement Conference on Enforcement Policy, Docket No. AD07-13-000, (FERC issued Nov. 16, 2007).

strength of a regulated company's commitment to compliance,"[78] thus removing any remaining doubt that developing a "culture of compliance" should be a high priority for energy companies.[79]

In addition, on May 15, 2008, the FERC adopted four related initiatives to clarify its enforcement policies and practices:

- A Revised Enforcement Policy Statement[80] to provide guidance on the factors that Enforcement Staff considers when determining whether to open an investigation, the procedures that the FERC and its staff will follow once an investigation is open, and how the agency determines penalties;
- An Interpretive Order[81] expanding the FERC's no-action letter (NAL) process to allow market participants to seek enforcement advice on all matters within the FERC's jurisdiction except hydroelectric project licensing, natural gas pipeline certification, LNG terminal operations, and mandatory reliability standards enforcement;
- A NOPR[82] to revise the rules governing off-the-record contacts and separation of functions for the FERC employees; and
- A Final Rule[83] that establishes the right of entities to respond when the FERC's OE recommends that the FERC issue a Show Cause Order.

Consistent with the requirements of the FERC's Interpretive Order, on July 8, 2008, the FERC held a workshop to discuss various elements of a successful compliance plan. The workshop panel included energy companies that provided details of their company's FERC regulatory compliance plans and discussed ways to maintain a robust culture of compliance within their organizations. The FERC is expected to hold additional workshops later in the year.

Details of the FERC's recent enforcement settlements orders and policy developments are summarized below.

78. Federal Energy Regulatory FERC, *Statement: Chairman Joseph T. Kelliher's statement on Enforcement Policy Conference* (November 14, 2007), http://www.ferc.gov/news/statements-speeches/kelliher/2007/11-14-07-kelliher.asp.

79. *Id.*

80. *Enforcement of Statutes, Orders, Rules, and Regulations*, 123 F.E.R.C. ¶ 61,156 (2008) (2008 Revised Policy Statement).

81. *Obtaining Guidance on Regulatory Requirements*, 123 F.E.R.C. ¶ 61,157 (2008) (Interpretative Order Modifying No-Action Letter Process and Reviewing other Mechanisms for Obtaining Guidance).

82. *Ex Parte Contacts and Separation of Functions*, 123 F.E.R.C. ¶ 61,158 (2008) [hereinafter *Ex Parte* NOPR].

83. *Submissions to the FERC upon Staff Intention to Seek an Order to Show Cause*, 123 F.E.R.C. 61,159 (2008).

A. FERC Enforcement Settlements

1. MGTC, Inc.[84]

MGTC owned and operated an intrastate pipeline system located in the state of Wyoming. MIGC, a jurisdictional pipeline, provided open-access firm and interruptible transportation services. MGTC held interruptible transportation capacity on MIGC. Anadarko acquired MGTC and MIGC. After the acquisition, Anadarko assessed MGTC operations which revealed violations of the "shipper-must-have-title" requirement.[85] The investigation revealed that MGTC transported 17.2 Bcf of natural gas owned by Kinder Morgan customers using interruptible transportation capacity on MIGC.[86] Anadarko self-reported to the FERC and the OE opened a preliminary, non-public investigation.

The OE and MGTC entered into an agreement wherein MGTC agreed to pay a civil penalty of 300,000 dollars for violation of the FERC's "shipper-must-have-title" requirement and make a compliance report to the FERC.[87] In assessing a penalty, the FERC relied on the following mitigating factors: (1) Anadarko, MGTC's new owner, promptly self-reported the violations; (2) the violations occurred in a small geographic area in Wyoming; (3) there was no demonstrable harm to the market or to market participants; and (4) Anadarko exhibited exemplary cooperation.[88]

2. BP Energy Co.[89]

BP conducted a self-assessment to check its compliance with the FERC's capacity release policies and regulations. The self-assessment revealed widespread violations of the applicable posting and bidding requirements for capacity release, the shipper-must-have-title requirement, and the FERC's prohibition on buy-sell transactions. BP self-reported to the FERC and OE opened a preliminary, non-public investigation that confirmed violations by BP on fourteen interstate pipeline or storage facilities involving 49.3 Bcf of natural gas.

Specifically, the FERC found that BP: (1) engaged in "flipping" 24.9 Bcf of natural gas – a series of repeated short-term releases of discounted rate capacity to two or more affiliated replacement shippers on an alternating monthly basis in order to avoid the competitive bidding requirement for discounted long-term capacity releases, (2) shipped 19.3 Bcf of natural gas owned by BP on transportation capacity held by its asset management customers without a valid release of that capacity to BP, and (3) transported and sold 5.1 Bcf of natural gas through prohibited buy-sell transactions.[90] The OE concluded that BP's violations were primarily the result of inadequate internal review and approval

84. 121 F.E.R.C. ¶ 61,087 (2007).
85. *Id.*
86. *Id.*
87. *Id.*
88. *Id.*
89. 121 F.E.R.C. ¶ 61,088 (2007).
90. *Id.*

mechanisms for identifying and correcting possible violations of the FERC's capacity release policies.

The OE and BP entered into an agreement wherein BP agreed to: (1) pay a civil penalty of 7,000,000 dollars, and (2) make two semi-annual compliance reports. In calculating the penalty, the FERC included the following mitigating factors: BP (1) self-reported and cooperated with the investigation, (2) uncovered the violations after conducting an internal investigation on its own initiative, and (3) took immediate self-corrective action.[91] However, the FERC also had to take into account the seriousness, in terms of volume and scope, of BP's violations, as they involved 49.3 Bcf of gas transportation and storage over fourteen pipeline systems. Moreover, the FERC found that BP's flipping violations were a deliberate attempt to circumvent FERC rules.

3. Entergy New Orleans, Inc. (ENOI).[92]

ENOI, a shipper with firm No Notice Service transportation capacity, entered into a series of natural gas supply contracts wherein the supplier held title to the gas while the gas was transported on ENOI's capacity. ENOI self-reported these shipper-must-have-title violations to the OE, which were confirmed in a subsequent investigation. In this case, ENOI transported approximately fifty Bcf of gas in violation of the shipper-must-have-title requirement. However, ENOI argued that it arranged its contracts in this manner in order to have the timing of the billing for the gas supply match the timing of the delivery of the gas, for purposes of ENOI's purchased gas adjustment filings with New Orleans. According to ENOI, its staff did not realize until 2007 that it was in violation of the shipper-must-have-title requirement.

ENOI and the OE reached an agreement wherein ENOI would pay a civil penalty of 400,000 dollars for violation of the FERC's "shipper-must-have-title" requirement.[93] In calculating the civil penalty, the FERC gave weight to the following mitigating factors: (1) ENOI self-reported the violations, (2) ENOI's violations caused no demonstrable harm to the market or to market participants, (3) the violations occurred on transportation used to serve only ENOI's retail customers, and (4) ENOI took prompt actions to remedy the violations.

4. Constellation New Energy - Gas Division, LLC (CNE-G.)[94]

CNE-G, a retail natural gas marketer, delivers natural gas to retail markets in several states through interstate pipeline and storage capacity. An internal review by CNE-G revealed possible violations of FERC requirements. An OE investigation confirmed that CNE-G violated the FERC's capacity release policies, shipper-must-have-title requirements, and prohibition against buy-sell transactions by engaging in flipping transactions. The flipping was part of a scheme to circumvent the competitive bidding process for discounted, long-term released capacity (12.9 Bcf of natural gas). CNE-G's shipper-must-have-title violations involved approximately 22.3 Bcf of natural gas transportation on

91. *Id.*
92. 122 F.E.R.C. ¶ 61,219 (2008).
93. *Id.*
94. 122 F.E.R.C. ¶ 61,220 (2008).

eleven pipeline and storage facilities, and CNE-G transported and sold 266,085 decotherms (Dth) of gas through prohibited buy-sell transactions.

The OE and CNE-G entered into an agreement wherein CNE-G agreed to pay a 5 million dollars civil penalty, disgorge unjust profits of 1,899,416 dollars plus interest, and implement a compliance-monitoring plan pursuant to which CNE-G would submit a compliance report on a semi-annual basis for a minimum period of two years. In calculating the penalty, the FERC gave weight to the following mitigating factors: (1) CNE-G self-reported and cooperated with the investigation, (2) CNE-G uncovered the violations after conducting an internal investigation on its own initiative, and (3) CNE-G took immediate self-corrective action including disciplinary action against senior management. However, the FERC also had to take into account: (1) the seriousness, in terms of volume and scope, of CNE-G's violations, as they involved 35.5 Bcf of gas transportation and storage over thirteen pipeline systems; (2) the serious nature of CNE-G's flipping violations because those transactions were a deliberate attempt to circumvent FERC rules; and (3) the role of CNE-G's senior management in the violations.[95]

B. FERC Enforcement Policy Developments

1. Revised Enforcement Policy Statement (Docket No. PL08-3)

The Revised Enforcement Policy Statement, which supersedes the 2005 Enforcement Policy Statement, carries forward many existing FERC enforcement policies, but also provided some adjustments. For example, the FERC provided additional guidance on factors considered in determining penalty amounts, and identified the elements of a strong compliance program. The FERC also adopted some procedural reforms, as discussed below.

With regard to penalty factors, the FERC again declined to create a standard formula or schedule of penalties for specific types of violations. Instead, the FERC provided more information on what it considers when assessing penalties under its enforcement authority. For example, the FERC reaffirmed that a primary consideration affecting the amount of a civil penalty is the seriousness of the violation. In addition to those enumerated in the 2005 Enforcement Policy Statement, the FERC identified several additional factors it examines in determining the seriousness of a violation, including:[96]

- What, if any, harm was there to the efficient and transparent functioning of the market?
- What are the earnings, revenues, and market share of the company that is under investigation?
- What penalty amount best discourages improper conduct, while not excessively discouraging beneficial market participation?
- What was the motivation of those accused of the improper conduct?
- Was the integrity of the regulatory process impaired?

95. *Id.*

96. *Revised Policy Statement on Enforcement*, 123 F.E.R.C. ¶ 61,156 (2008).

- Was there risk of serious harm, even if the actual harm was slight or non-existent?

The FERC also reaffirmed that, when calculating penalties, it considers the nature and extent of the company's internal compliance program in existence when the violation occurred. Although the FERC's assessments are made on a case-by-case basis, the Revised Enforcement Policy Statement identified the following actions as indicative of a strong compliance culture:[97]

- Preparing an inventory of current compliance risks and practices;
- Creating an independent Compliance Officer who reports to the Chief Executive Officer and the Board, or to a committee thereof;
- Providing sufficient funding for the administration of compliance programs;
- Identifying measurable performance targets;
- Tying regulatory compliance to personnel assessments and compensation, including management compensation;
- Providing for disciplinary consequences for infractions of the FERC requirements;
- Providing frequent mandatory training programs, including relevant "real world" examples and a list of prohibited activities;
- Implementing an internal "Hotline" through which personnel may anonymously report suspected compliance issues; and
- Implementing a comprehensive compliance audit program, including the tracking and review of any incidents of noncompliance, with submission of the results to senior management and the Board.[98]

The Revised Enforcement Policy Statement reiterated the value of self-reporting violations to the FERC, noting that in the cases where a self-report ended in an enforcement action, the FERC would have imposed greater penalties had the agency discovered the violation on its own. The FERC also identified staff guidance as a factor in determining a civil penalty amount. If an entity reasonably relies, in good faith, on staff guidance to engage in an activity that is subsequently determined to violate the FERC's rules and regulations, the entity may still receive mitigation credit. On the other hand, if an entity seeks but then ignores staff guidance on an activity that is subsequently found to violate the FERC's rules and regulations, ignoring the advice could be an aggravating factor when the FERC sets a penalty. This addition to the list of factors the FERC uses to determine a civil penalty is useful because the regulated community often relies on informal (but non-binding) staff guidance, and may provide an incentive to seek such guidance.

97. *Id.*
98. *Id.*

2. Obtaining Regulatory Guidance (Interpretive Order) (Docket No. PL08-2)[99]

The Interpretive Order was adopted in response to comments at, and following the November 2007 Enforcement Conference, requesting more Staff guidance on potential enforcement actions. A principal component of the Interpretive Order is the expansion of the NAL process. Previously, the NAL process was limited to questions concerning the Standards of Conduct for transmission providers, Affiliate Restrictions for electric sellers, Codes of Conduct for natural gas sellers, and the Market Behavior Rules. Now, market participants can submit NAL requests on any issue that falls within the FERC's jurisdiction, except for issues related to hydroelectric project licensing, natural gas pipeline certification, and LNG terminal operations.[100] Enforcement of reliability standards also is excluded because the North American Electric Reliability Corporation (NERC)[101] and the Regional Entities have front-line responsibility for enforcement of those standards.

The Interpretive Order also announced the FERC's intention to establish a compliance "help desk" on the FERC website. The help desk will provide a means for submitting questions on FERC's regulations and will put a requestor in touch with the right staff member at the FERC. In response to requests for greater clarity in the FERC's rules, the FERC directed its staff to hold occasional workshops to discuss areas of concern regarding compliance. The FERC also noted that Staff may use these workshops to develop and post additional FAQs on the FERC web site.

3. NOPR on Ex Parte Contacts and Separation of Functions

In this NOPR, the FERC proposed that separation-of-function restrictions between decisional employees (*e.g.*, the FERC FERCers and their staffs) and non-decisional employees would begin to apply when adversarial proceeding are initiated, such as when a show cause order is issued or a civil action is commenced.[102] Prior to this time, all FERC employees may communicate with each other on the investigation. In addition, as noted in the Revised Enforcement Policy Statement, the subject of a Part 1b investigation cannot communicate, in person or by telephone, with the FERC FERCers or their assistants regarding the investigation. Such communications are limited to written submissions.

The FERC also proposed to clarify that intervention is not permitted as a matter of right in proceedings related to Part 1b investigations. The FERC may allow interventions when a party has a clear interest in a matter and the investigation is at a point where third-party involvement is warranted (*e.g.*, in the damages stage).

4. Submissions to the FERC upon Staff Intention to Seek a Show Cause

99. *Obtaining Guidance on Regulatory Requirements*, 123 F.E.R.C. ¶ 61,157 (2008).

100. *Id.*

101. *Id.*

102. *Ex Parte Contacts and Separation of Functions*, F.E.R.C. STATS & REGS. ¶ 32,634 (2008).

Order (Order No. 711)[103]

The FERC has historically allowed its Enforcement Staff to determine when an investigated entity could respond to a recommendation that the FERC issue a show cause order. The FERC regulations now provide that, if Staff intends to recommend that the FERC issue a show cause order, the subject, in "all but extraordinary circumstances," has the right to be informed of the recommendation and to provide a written, non-public response to Staff's recommendation.[104] After receiving staff's notice, the subject has thirty days to submit its response to staff.[105]

III. RATES, TERMS AND CONDITIONS OF SERVICE

A. Rates

1. Florida Gas Transmission Company, LLC

On March 1, 2007, Florida Gas Transmission Company, LLC (Florida Gas) filed to recover the depreciation expense and pretax return on certain defined capital expenditures (Capital Costs) through a surcharge (Capital Surcharge) under its Rate Schedules FTS-1 and SFTS pursuant to Article IX of the stipulation and agreement of settlement (settlement), filed on August 13, 2004, in Docket Nos. RP04-12 and RP00-387,[106] and section twenty-six of the General Terms and Conditions (GT&C) of its tariff. Following the receipt of a protest to the filing, and Florida Gas' answer, on March 30, 2007,[107] the FERC accepted and suspended the revised tariff sheet to become effective April 1, 2007, subject to refund and further review. The March 30, 2007, order permitted the parties to file a response to Florida Gas' answer to the protests. Upon review of the record in the proceeding, the FERC found that Florida Gas had sufficiently supported its filing and removed the refund condition established by the March 30, 2007 Order.

Section twenty-six of the GT&C of Florida Gas' FERC Gas Tariff defines which costs are eligible for recovery pursuant to the Capital Surcharge.[108] Specifically, section twenty-six provides that Capital Costs are costs resulting from capital additions placed into service and retirements of facilities removed from service for those expenditures necessary to: " (i) enhance system security (Security Costs); (ii) comply with the provisions of the Pipeline Safety Improvement Act of 2002 (PSIA) and regulations issued thereunder (Integrity Costs); and (iii) relocate or replace portions of [Florida Gas'] system to accommodate expansions or improvements to the Florida Turnpike, as required

103. Order No. 711, *Submissions to the FERC upon Staff Intention to Seek an Order to Show Cause*, F.E.R.C. STATS & REGS. ¶ 31,270, 123 F.E.R.C. ¶ 61,159 (2008).

104. *Id*.

105. *Id*.

106. *Florida Gas Transmission Co.*, 109 F.E.R.C. ¶ 61,320 (2004) (The settlement was conditionally approved by FERC order dated December 21, 2004).

107. *Florida Gas Transmission Co.*, 118 F.E.R.C. ¶ 61,264 (2007).

108. *Id.*

by the Florida Department of Transportation (Turnpike Costs) (collectively, Capital Costs)."[109]

The FERC stated that the central issue in this case involves the question of how certain costs are to be allocated under a rate settlement between two rate schedules on Florida Gas' system: the "non-incremental system" Rate Schedule FTS-1 and SFTS rates, or the "incremental system" Rate Schedule FTS-2 rates, not the level of the Capital Costs to be recovered.[110] The FERC found that the settlement and section twenty-six of the GT&C of Florida Gas' tariff were intended to establish a simple cost allocation process based on which facilities are worked on, rather than requiring a difficult and highly debatable analysis, of which, customers benefit from the work performed.[111] The FERC found, consistent with the settlement and section twenty-six, that Florida Gas had shown that the instant costs should be allocated to the Rate Schedules FTS-1 and SFTS rates for non-incremental facilities.[112]

2. Equitrans, L.P.

On March 1, 2007, Equitrans, L.P. (Equitrans) filed to institute a surcharge to recover certain costs incurred by Equitrans under the PSIA.[113] The surcharge is based on a settlement approved by the FERC on April 6, 2006, in a "Section 4" rate case.[114] Equitrans asserted these costs are "Qualifying Costs" pursuant to section thierty-eight of the GT&C of its tariff.[115] The filing was protested. On March 29, 2007, the FERC issued an order,[116] which accepted and suspended the proposed tariff revisions, subject to refund and condition, and subject to the outcome of a technical conference. A technical conference was convened and comments were filed. On November 26, 2007, the FERC issued a letter order which removed the refund condition, and accepted Equitrans' proposal and the subject tariff sheets effective April 1, 2007,[117] without further condition.

3. NSTAR Gas Company v. Algonquin Gas Transmission, LLC[118]

On February 14, 2008, the FERC issued an order on complaint and offer of settlement that included approval of two limited Section 4 rate filing by Algonquin Gas Transmission, LLC (Algonquin).[119] On April 9, 2007, NSTAR Gas Company (NSTAR) filed a complaint against Algonquin alleging that Algonquin's potential curtailment of service on its J-2 pipeline, in order to inspect the pipeline in compliance with the United States Department of

109. *Id.*
110. *Id.*
111. *Id.*
112. *Id.*
113. *Equitrans, L.P.*, 115 F.E.R.C. ¶ 61,007 (2007).
114. *Id.*
115. Letter Order, *Equitrans, L.P.*, 121 F.E.R.C. ¶ 61,199 (2007) (§ 38 is entitled "Pipeline Safety Cost Tracker (PSCT) Mechanism,").
116. *Equitrans, L.P.*, 118 F.E.R.C. ¶ 61,258 (2007).
117. *Equitrans, L.P.*, 121 F.E.R.C. ¶ 61,199 (2007).
118. 122 F.E.R.C. ¶ 61,131 (2008).
119. *Id.*

Transportation (DOT) inspection requirements, violates Algonquin's tariff and firm service contract with NSTAR. Following the filing of the complaint, Algonquin and NSTAR participated in FERC-sponsored mediation in an effort to resolve the proceeding.

"On October 16, 2007, Algonquin and NSTAR filed a Stipulation and Agreement pursuant to Rule 602 of the ['FERC's] regulations purporting to resolve all issues raised by the complaint."[120] The FERC found that, "the proposed settlement contemplate[d] actions requiring separate authorizations from the [FERC] which cannot be issued in this proceeding and which will affect entities that are not parties to this proceeding and/or were excluded from the negotiations leading to the proffered settlement."[121] The FERC found that, "the proposal set forth in the Stipulation and Agreement between Algonquin and NSTAR generally provide[d] a reasonable framework for addressing the problems highlighted by NSTAR's complaint" and the proposal was preliminarily approved by the FERC, "pending the filing and [FERC] consideration of appropriate applications."[122] Two of those applications involved the filing of limited Section 4 filings.

The FERC authorized Algonquin to make a limited Section 4 filing to provide that shippers who do not contract for service on the combined J-2 facility will not have access to delivery points downstream of the head of that facility and to remove the costs of the existing facilities from its system rates. The order noted that the limited Section 4 filing will not take effect until the in-service date of the new J-2 facilities, which is not expected to occur until approximately eight months after the end of the December 31, 2008, rate moratorium. However, to the extent the timing of that filing raises issues related to the rate moratorium, the FERC stated that those issues could be better addressed in that proceeding.[123]

In addition, the FERC noted that it cannot change Algonquin's rates for its existing services in a "Section 7" proceeding.[124] The FERC stated that the settlement's proposal to remove the ability of existing shippers to access the existing J-2 pipeline under the system rate is a change to an existing term and condition of service, and cannot be approved in a Section 7 proceeding.[125] Therefore, the FERC authorized Algonquin to file a limited Section 4 proceeding to remove the delivery point at the end of the J-2 system from the list of delivery points available for use by shippers on the mainline system, and add to that list a delivery point at the head of the facilities. The FERC found that,

> [i]n proposing such a change, which will serve to remove the availability of the existing J-2 pipeline from Algonquin's mainline system and to designate it as a new lateral pipeline that will be subject to the new incremental recourse rate, Algonquin

120. *Id.*
121. *Id.*
122. *Id.*
123. *Id.*
124. *Id.*
125. *Id.*

> must also remove all costs associated with the existing J-2 pipeline from its system rate as the mainline rate will no longer provide any access to the J-2 facilities.[126]

Until Algonquin receives authorization to make this change to its tariff, it will be required to continue to provide service on the J-2 pipeline under its existing interruptible and/or secondary firm service obligations.[127]

4. Discovery Gas Transmission, LLC[128]

On March 6, 2008, Discovery Gas Transmission, LLC (Discovery) filed tariff sheets in Docket No. RP08-70-001 to comply with the FERC's Letter Order issued February 5, 2008.[129] The February fifth Order approved a Stipulation and Settlement Agreement (Settlement) for all consenting parties. In the March sixth compliance filing, Discovery included the calculation of its initial Hurricane Mitigation & Reliability Enhancement (HMRE) surcharge to be effective January 1, 2008. Discovery states that the calculation derives an initial HMRE surcharge that is slightly less than that estimated in the settlement.[130] The initial costs to be recovered by Discovery are 1,649,870 dollars for an initial HMRE Surcharge of 0.0096 dollars/Dth. On April 4, 2008, the Director of the Office of Energy Market Regulation issued a letter order that accepted the compliance tariff sheets to become effective January 1, 2008.[131]

B. Policy Statement on the Use of Master Limited Partnerships (MLPs) for Return on Equity (ROE) Determinations

On April 17, 2008, the FERC issued a statement of policy concerning employing publicly traded MLPs as proxy companies for the purpose of establishing the allowed rate of ROE in determining rates for jurisdictional oil and natural gas pipelines.[132] The MLP Policy Statement establishes a policy of permitting MLPs to be included in proxy groups used to determine return on equity for gas and oil pipelines, subject to case-by-case determinations of the propriety of relying on the particular entities proposed and to other parameters stated by the FERC.[133] The new policy will apply, the FERC held, to all oil and gas pipeline rate proceedings pending before the FERC on the date of the

126. *Id.* at 61,136.

127. *Id.*

128. 122 F.E.R.C. ¶ 61,099 (2008).

129. *Id.*

130. *Id.*

131. *Id.*

132. *Composition of Proxy Groups for Determining Gas and Oil Pipeline Return on Equity*, 123 F.E.R.C. ¶ 61,048 (2008) (The MLP Policy Statement was the culmination of a proceeding the FERC initiated with its issuance of a proposed policy statement on July 19, 2007); *see also, Composition of Proxy Groups for Determining Gas and Oil Pipeline Return on Equity*, 120 F.E.R.C. ¶ 61,068 (2007) [hereinafter *Proposed Policy Statement*]. The Proposed Policy Statement solicited initial and reply comments from interested parties. After receipt of those comments, the FERC determined that it required additional information on the issue of the proper growth rates to use for MLPs in the DCF analysis the FERC uses to establish pipeline rates of return on equity. The FERC thus convened a technical conference and solicited additional comments and reply comments on that topic. *See also, Composition of Proxy Groups for Determining Gas and Oil Pipeline Return on Equity*, Notice of Technical Conference and Request for Additional Comments, 121 F.E.R.C. ¶ 61,165 (2007).

133. 123 F.E.R.C. ¶ 61,048.

policy's adoption in which the return on equity had not yet been finally determined.[134]

The FERC explained that changes in the pipeline industry created the need for it to examine the use of MLPs as proxy companies for purposes of applying the discounted cash flow (DCF) model it employs to establish the rate of return on equity.[135] The FERC historically required proxies to meet three criteria: (1) that "the [entity's common] stock must be publicly traded"[136], (2) that "the company be recognized [by investors as a pipeline company] and [that] its stock must be recognized and tracked by an investment information service such as Value Line,"[137] and (3) that "pipeline operations constitute a high proportion of the company's business."[138] However, due to mergers, acquisitions and other developments, the number of gas pipeline corporations that meet these criteria has declined. Further, there are no oil pipeline corporations that can be used as proxies for regulated oil pipelines.[139] Also, the FERC noted, the United States Court of Appeals for the District of Columbia Circuit, in a decision handed down approximately one month after the FERC issued the Proposed Policy Statement,[140] established that it is "crucial that the firms in the proxy group be comparable to the regulated firm whose rate is being determined,"[141] *i.e.*, the proxies must be "risk-appropriate."[142]

Based on the record developed in response to the Proposed Policy Statement, the FERC determined that it will allow MLPs in proxy groups used to determine return on equity for natural gas and oil pipelines. The FERC reasoned that the transfer of increasingly extensive gas pipeline assets to publicly traded MLPs, "whose business is narrowly focused on pipeline activities,"[143] means that pipeline MLPs "are likely to be more representative of predominantly pipeline firms than the diversified gas corporations still available for inclusion in a proxy group."[144] In addition, the FERC stated, proxy groups that include gas pipeline MLPs should be more comparable in terms of business risk than the diversified

134. 123 F.E.R.C. ¶ 61,048 at P 54, 116.

135. The DCF model "is based on the premise that 'a stock's price is equal to the present value of the infinite stream of expected dividends discounted at a market rate commensurate with the stock's risk.'" 123 F.E.R.C. ¶ 61,048 at P 4, *quoting Canadian Ass'n of Petroleum Producers v. F.E.R.C.*, 254 F.3d 289, 293 (D.C. Cir. 2001). The FERC uses the DCF formula to solve for the rate of return that investors require to invest in jurisdictional pipelines' equity securities (common stock, in the case of corporations, or limited partnership (LP) units, in the case of MLPs). Since most jurisdictional oil and gas pipelines are subsidiaries of other entities and do not have publicly traded equity securities, "the [FERC] must use a proxy group of publicly traded firms with corresponding risks to set a range of reasonable returns for both natural gas and oil pipelines." 123 F.E.R.C. ¶ 61,048 at P 7. After determining the range of returns for the proxy group, "the [FERC] assigns the pipeline a rate within that range or zone, to reflect specific risks of that pipeline as compared to the proxy group companies." *Id.*

136. 123 F.E.R.C. ¶ 61,048 at P.8

137. *Id.*

138. *Id.*

139. *Id.* at P 1.

140. Petal Gas Storage, LLC v. F.E.R.C., 496 F.3d 695 (D.C. Cir. 2007) [hereinafter, *Petal*].

141. 123 F.E.R.C. ¶ 61,048 at P 48.

142. *Id*., quoting Petal, 496 F.3d at 699.

143. Id. at P 49.

144. *Id.*

gas companies on which the FERC previously relied.[145] MLPs are the only publicly traded entities engaged in the oil pipeline business, so MLPs are "the most representative group for determining the equity cost of capital for oil pipelines."[146]

The FERC did not, however, decide which corporations or MLPs should or should not be included in proxy groups. Instead, it left that determination to be made in individual pipeline rate cases.

Having determined that MLPs are eligible to be included in proxy groups, the FERC also addressed a number of issues concerning how MLPs' financial data will be used in DCF calculations. Specifically:

The entire amount of an MLP's cash distributions to unit holders will be used to calculate the MLP's yield. The FERC concluded that its previously proposed cap on such distributions at an amount equal to the MLP's earnings per unit would be inconsistent with the DCF theory because it would use less than the market-determined yield of MLPs in the calculation of the required return for MLPs.[147]

It is unnecessary to address the long-term sustainability of MLP earnings generally, or of any particular MLP proxy. If earnings are not sustainable, that will be reflected in analysts' projected rates of growth and, ultimately, in the market price for the MLP units.[148]

The five-year earnings growth projections published by Institutional Brokers' Estimate System (IBES) should be used as the short-term growth factor for MLP proxies, just as they are for proxy companies that are corporations.

The long-term growth factor for MLP proxies should be equal to one-half the estimated rate of long-term growth in U.S. gross domestic product (GDP), which is used as the long-term growth factor for corporation proxies. Based primarily on evidence that several major investment banks use long-term growth rates for MLPs that are less than the long-term GDP growth rate, the FERC concluded that investors generally expect MLPs' long-term rate of growth to be substantially less than GDP growth.[149] This is also consistent, the FERC stated, with the fact that MLPs are limited by law to a narrower range of investment opportunities than corporations and their relatively greater reliance on external sources of capital, rather than retained earnings, to finance their growth.[150] The FERC selected fifty percent of the long-term GDP growth projection based on the range of long-term MLP growth rates used by investment houses.[151]

The short-term and long-term growth factors will be weighted two-thirds/one-third, respectively, for MLP proxies, just as they are for corporation proxies.

145. *Id.*
146. *Id.*
147. *Id.* at PP 57-62.
148. *Id.* at PP 64-65.
149. *Id.*
150. *Id.* at PP 89-94.
151. *Id.* at P 96.

C. *Hourly Flexibility for Transportation Service*[152]

On December 7, 2007, Columbia Gas Transmission Corporation (Columbia) filed tariff sheets to establish an hourly no-notice summer-only transportation service via Rate Schedule NTS-S (NTS-S Service) designed to provide enhanced summer-only hourly flexibility exceeding 1/24th of a shipper's MDQ.[153] Columbia proposed NTS-S Service to allow electric generators, as well as other shippers valuing enhanced hourly service, to take firm services more tailored to their needs, especially for scheduling and dispatching gas-fired electric generation and scheduling the gas necessary to fuel such generators. On March 20, 2008, the FERC issued an order[154] accepting the proposed tariff sheets as proposed:

> Columbia state[d] that NTS-S Service would allow shippers to accelerate flow rates without notice during any hour within the gas day, by permitting them to take up to their Maximum Hourly Quantity (MHQ) and up to the MDQ set forth in their service agreement without submitting an accurate nomination. Columbia explain[ed] that, as with its existing Rate Schedule NTS... transportation service, NTS-S Service will be provided on a no-notice basis and will benefit shippers by providing the means of avoiding Columbia's Delivery Point Scheduling Penalty.[155]
>
> * * *
>
> [The proposed] "NTS-S Service will provide the flexibility on any hour during the gas day to request deliveries of gas from Columbia that exceed the quantities of gas the customer has scheduled to be received by Columbia, without incurring an overrun charge except that a shipper's MHQ cannot be less than 4.17 percent or exceed 100 percent of its MDQ. Columbia's shippers taking Off-Peak Firm Transportation Service (OPT Service) and FTS Firm Transportation Service (FTS) [had a] one-time right to convert their summer period service to NTS-S Service while retaining their firm rights to winter firm capacity under OPT or FTS.[156]
>
> * * *
>
> [Columbia stated that, as with Columbia's existing NTS service] "customers will have a running Gas Supply Quantity (GSQ) balance that, to the extent drawn upon during the month (*i.e.,* when deliveries exceed GSQ draws), must be replenished by the customer no later than the last day of the month immediately following the month in which the GSQ draws were taken. A shipper failing to replenish its GSQ balance must pay a penalty equal to the unreplenished quantity multiplied by 120 percent of the applicable index price for gas delivered to "Columbia Gas Transmission Corporation, Appalachia," as reported in *Inside FERC's Gas Market Report*.[157]

However, Columbia noted that, unlike NTS Service, NTS-S Service will be provided only during the summer season (April first through September thirtieth).[158] Columbia stated that transportation capacity under Rate Schedule NTS-S will be subject to capacity release.[159] However, the capacity will be released as if under Rate Schedule FTS, unless the customer's GSQ is also released to the replacement shipper.

152. 122 F.E.R.C. ¶ 61,239 (2008).
153. *Id.*
154. *Id*.
155. *Id.* at P 4.
156. *Id.*
157. *Id.* at P 5.
158. *Id.*
159. *Id.* at P 6.

In order to provide NTS-S Service to a wide array of shippers, Columbia stated that NTS-S Service would be provided to all primary points of delivery on its system regardless of whether they are directly connected or are equipped with electronic metering and flow control devices.[160] Instead of requiring this equipment, Columbia stated that it will manage NTS-S Service using its SST Service shippers' coinciding summer season (April first - September thirtieth) fifty percent contract demand reduction.[161] If hourly customers abuse over-takes, Columbia stated that it would require them to install flow control devices at their own expense.[162] Subject to operational availability, shippers may use secondary points of receipt and other qualified points of delivery on Columbia's system as secondary points of delivery.

The March twentieth order noted that the FERC had approved hourly firm transportation services for numerous pipelines,[163] and hourly no-notice services similar to the one Columbia is proposing here.[164] The FERC found that NTS-S Service will benefit electric generators (as well as other shippers valuing enhanced hourly service) by providing firm services more tailored to their specific needs. The order stated that NTS-S Service's flexibility for scheduling gas should improve both the scheduling of gas used to fuel electric generators, and the scheduling and dispatch of gas-fired electric generation, thereby furthering the FERC's goal of improving reliability in the gas and electric industries.[165]

With regard to charges for shippers converting to NTS-S service, Columbia proposed that when considering a request to convert to NTS-S Service, it will project the total demand revenues lost under the OPT or FTS contracts and compare it to the total projected demand revenues for the requested NTS-S Service.[166] If conversion would cause Columbia to lose revenues, it reserved the right to reject the request. The FERC found Columbia's proposal is reasonable as a condition of allowing conversion to the new service.[167] The FERC found this consistent with established precedent keeping pipelines whole (revenue-

160. *Id.* at P 7.

161. *Id.*

162. *Id.*

163. *El Paso Nat. Gas Co.*, 112 F.E.R.C. ¶ 61,150 (2005), *order on technical conference*, 114 F.E.R.C. ¶ 61,305 (2006), *reh'g denied*, 116 F.E.R.C. ¶ 61,016 (2006), *order approving settlement*, 120 F.E.R.C. 61,208 (2007); *Great Lakes Gas Transmission Ltd. P'ship*, 120 F.E.R.C. ¶ 61,105 (2007); *Vector Pipeline, L.P.*, 103 F.E.R.C. ¶ 61,391 (2003), o*rder accepting settlement*, 106 F.E.R.C. ¶ 61,071 (2004); *Portland Nat. Gas Transmission Sys.*, 106 F.E.R.C. ¶ 61,289 (2004), *reh'g denied*, 110 F.E.R.C. ¶ 61,375 (2005), *order on compliance filing*, 111 F.E.R.C. ¶ 61,430 (2005).

164. *El Paso Nat. Gas Co*., 112 F.E.R.C. ¶ 61,150 (2005), *order on technical conference*, 114 F.E.R.C. ¶ 61,305 (2006), *reh'g denied*, 116 F.E.R.C. ¶ 61,016 (2006), *order approving settlement*, 120 F.E.R.C. ¶ 61,208 (2007) (approving implementation of hourly no-notice service under Rate Schedule NNTH).

165. Order No. 698, *Standards for Business Practices for Interstate Natural Gas Pipelines; Standards for Business Practices for Public Utilities*, F.E.R.C. STATS. & REGS. ¶ 31,251 (2007) (codifed at 18 CFR pts. 38, 284).

166. 122 F.E.R.C. ¶ 61,239 at n. 24.

167. *Id.*

wise) when allowing shippers to convert their service[168] for example, allowing pipelines to assess a surcharge for any revenue shortfall due to converting from one rate schedule to another.

A comment was filed stating that Columbia's proposed service was unacceptable because Columbia has not demonstrated that it cannot provide a comparable hourly service throughout the year.[169] The FERC stated it does not require pipelines to offer any hourly services.[170] The FERC found Columbia's proposal to limit its proposed hourly service to the summer reasonable, in light of its assertion that the service will use capacity made available due to the fifty percent reduction in contract demand for SST Service during the Summer Period.[171]

Parties asserted that because NTS-S Service will use capacity available from seasonal reductions in contract demand for Rate Schedule SST, the costs of NTS-S Service have been allocated to other services and are already being recovered.[172] The FERC responded that in-between rate cases, the FERC accepts initial rates for new services if designed properly based on a currently-approved cost-based rate.[173] Issues regarding the levels and allocation of costs can be addressed in the pipeline's next rate case. Here, Columbia's NTS-S Service rates are appropriately based on its existing no notice NTS Service rates, and are adjusted to give consideration to the hourly flexibility under this new service. The FERC also found that the proposed rates were consistent with rates allowed for enhanced hourly flexible no notice service on other pipelines.[174] Based on these factors, the FERC found Columbia's proposed rate formula to be adequately supported.

D. Nonconforming Service Agreements

Pipelines must include in their tariff a form of service agreement, and file for review any contract that deviates materially from that form of service agreement.[175] A material deviation includes "“any provision of a service agreement which goes beyond the filling in of the spaces in the form of service agreement with the appropriate information provided for in the tariff and that affects the substantive rights of the parties.”[176] Where terms materially deviate from the tariff, the FERC typically requires that the terms be removed from the

168. *Transcontinental Gas Pipe Line Corp.*, 67 F.E.R.C. ¶ 61,372 at 62,269 (1994); *Texas Eastern Transmission Corp.*, 63 F.E.R.C. ¶ 61,100, at 61,445 (1993), *order on reh'g*, 64 F.E.R.C. ¶ 61,305, at 63,274 (1993).

169. 122 F.E.R.C. ¶ 61,239 at n. 27.

170. *Id.*

171. *Id*.

172. *Id.*

173. *See, generally, Panhandle Eastern Pipeline Co.*, 90 F.E.R.C. ¶ 61,119 (2000).

174. *Id.*

175. 18 C.F.R. §§ I54.1(d), 154.110 (2008).

176. *Transwestern Pipeline Co., LLC*, 121 F.E.R.C. ¶ 61,110 at P 12 (2007) *citing Columbia Gas Transmission Corp*., 97 F.E.R.C. ¶ 61,221 at 62,002 (2001).

contract unless they are made available to similarly situated shippers under the tariff. The FERC continues to refine the scope of "material deviation."[177]

1. Northern Natural Gas Co.

Northern Natural Gas Co.,[178] filed for FERC approval of a non-conforming service agreement that provided the particular customer with the right to receive gas at an hourly flow rate of up to 4.16 percent of its contract entitlement, rather than that percentage of the confirmed volumes scheduled, as was provided to other customers under the general terms of the tariff. Certain other customers protested that allowing only this one customer 4.16 percent of contract entitlement rather than of scheduled volumes, provided that customer with an undue preference.[179] The FERC, affirming *Columbia*[180] and *Transwestern,*[181] found that the enhanced hourly flow right was a material deviation from the form of service agreement, which would not be approved because it would provide a level of flexibility that is unavailable to other customers. The FERC, thus, conditioned acceptance of the provision on the pipeline's revising its tariff to "offer the hourly flow right on a generally applicable basis to all similarly situated shippers and operators."[182] The FERC also found that a provision in the filed contract that required that the pipeline to take certain actions depending on the FERC's disposition with respect to the filed agreement, was materially non-conforming, but would be approved because it did not affect the quality of service the customer would receive and thus did not pose a risk of undue discrimination against similarly situated other customers.[183]

2. Stingray Pipeline Company, L.L.C.

In *Stingray Pipeline Company, LLC,*[184] as a part of an effort to standardize and clarify its tariff provisions and procedures for implementing discounted rates, the pipeline filed for FERC review a number of service agreements that were potentially non-conforming in various respects. For the most part, these agreements had been in effect and service provided there-under for some years. The FERC found that all of the agreements contained provisions that deviated from Stingray's respective pro forma service agreements, and were thus each "non-conforming." It found that the "vast majority of material deviations" identified in Stingray's agreements [were] permissible, [because] they [were] either "allowed under [the pipeline's] generally applicable tariff, or [were] administrative or non-substantive in nature and [thus] pose[d] no threat of undue

177. *East Tennessee Natural Gas Company*, 107 F.E.R.C. ¶ 61,197 (2004). (In various orders, the FERC has determined that the following negotiated terms, among others, would be considered material changes to the form of service agreement: assignment clause, predetermination (termination) clause, "regulatory matters and the rights of parties to renegotiate the service if the [FERC] modifies the agreement," choice of law, provider of last resort rights, and pressure and hourly flow obligations.) *Id.* at P 24.

178. 123 F.E.R.C. ¶ 61,014 (2008).

179. *Id.* at P 3.

180. 97 F.E.R.C. ¶ 61,221.

181. 121 F.E.R.C. ¶ 61,110.

182. 123 F.E.R.C. ¶ 61,014 at P 10.

183. *Id.* at P 14.

184. 121 F.E.R.C. ¶ 61,216 (2007).

discrimination among shippers."[185] The FERC accepted the agreements subject to certain conditions relating to specific non-conforming provisions, discussed below.

The FERC required removal from certain agreements of provisions for "retroactive billing," which allowed the retroactive removal of a discount applied if a shipper transported all natural gas produced from a specified block or blocks on the pipeline's system, but it was later revealed that the shipper violated that condition.[186] Applying an earlier order on the same pipeline system,[187] the FERC found that the discount could be removed only prospectively.[188]

Relying on its ruling in *ANR Pipeline Co.*,[189] the FERC found that provisions in one contract allowing a shipper to unilaterally adjust its contractual MDQ during the term of the contract offered too much potential for undue discrimination among shippers, and must be removed, unless the pipeline offered the provision to all shippers through its tariff.[190]

The pipeline recognized that a provision in an agreement that a discount would be removed if the capacity was assigned was against FERC policy[191] and stated it would not enforce it. The FERC ordered the provision removed from the contract.[192]

The FERC in an earlier order on the same pipeline ruled that the pipeline could require shippers to obtain its consent to the assignment of a reserve dedication agreement that provided a discount and underlying service agreement to another party, so that Stingray can review such matters as the creditworthiness of the new shipper.[193] It found, however, that, assuming consent to the assignment of the underlying service agreement and reserve dedication, the pipeline must permit assignment of the discounted rate to the new owner of the dedicated reserves. Thus, the FERC required removal of a contract provision which appeared to give discretion to the pipeline to not allow assignment of the discount.[194]

The FERC also granted the pipeline waiver of section 154.601 of its regulations. The FERC allowed the agreements to remain in effect, subject to the conditions set out in the order, pursuant to amendments to the contracts, rather than superseding executed service agreements, as would otherwise have been required by the regulation.[195]

185. *Id.* at P 10.

186. *Id.* at 11-16.

187. *Stingray Pipeline Co., LLC*, 115 F.E.R.C. ¶ 61,161 at P 7, *order on clarification and compliance filing*, 117 F.E.R.C. ¶ 61,028 (2006).

188. 121 F.E.R.C. ¶ 61,216 at P 12.

189. 97 F.E.R.C. ¶ 61,224 at 62,025 (2001).

190. 121 F.E.R.C. ¶ 61,216 at P 14.

191. *Natural Gas Pipeline Co. of America*, 77 F.E.R.C. ¶ 61,028 (1996).

192. 121 F.E.R.C. ¶ 61,216 at P 15.

193. 115 F.E.R.C. ¶ 61,161 (2006), *order on clarification and compliance filing*, 117 F.E.R.C. ¶ 61,028 at PP 10-11 (2006).

194. 121 F.E.R.C. ¶ 61,216 at P 20.

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

3. Iroquois Gas Transmission, LP

In two orders involving a filing by Iroquois Gas Transmission, LP,[196] the FERC addressed a non-conforming, negotiated rate agreement that granted to a particular customer flexible receipt point rights and the right to a contract demand adjustment. The FERC had initially identified this contract as potentially creating material deviations from the form of service agreement, and sought additional information about the length of the agreement, whether it was in fact interim in nature, and whether it would affect other shippers' rights.[197] The pipeline submitted further justification for the contract, explaining that the contract provisions were not interim, but that following the completion of the proposed "Market Access" expansion project, the shipper would have similar rights, which could not be available to other shippers due to operational constraints. In the February fifth Order, the FERC restated its conclusion that providing one shipper with a "special right" to modify primary points and to adjust contract demand posed the potential for harm to other shippers, but that it had appeared that the right might be of an interim nature pending completion of the expansion project.[198] Although the FERC was potentially willing to permit such non-conforming rights as a temporary measure, it found that the proposal to make such rights permanent impermissibly conflicted with the FERC's policy in this regard, and required that these provisions be removed from the contracts.[199] On rehearing, the pipeline undertook to revise the long-term provisions of the contract, but sought permission to include the special provisions permitting flexibility as to primary point and contract demand based on the unique operational needs of the shipper during the period prior to completion of the pipeline expansion project, with the assurance that the special rights would not be part of the long-term contract to take effect after the pipeline project is completed. On rehearing, the FERC determined to permit the flexible receipt point/contract demand adjustment provision during the duration of an interim contract to terminate upon the in-service date of the Market Access Project.[200] The FERC noted the special operational circumstances and the lack of impact on other customers as grounds permitting these material deviations for an interim period.[201]

196. *Iroquois Gas Transmission, LP*, 122 F.E.R.C. ¶ 61,102 (February 5, 2008), *order on reh'g*, 123 F.E.R.C. ¶ 61,171 (May 16, 2008).

197. *Iroquois Gas Transmission, LP*, 121 F.E.R.C. ¶ 61,212 (2007).

198. *Iroquois Gas Transmission System, LP*, 122 F.E.R.C. ¶ 61,102 (2008).

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

200. *Iroquois Gas Transmission System, LP*., 123 F.E.R.C. ¶ 61,171 (2008).

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

IV. INFRASTRUCTURE

A. Pipeline Projects

1. CIG High Plains

On March 21, 2008, the FERC authorized CIG to construct an 899,000 dekotherms of gas per day (Dth/d) mainline that extends from Cheyenne to Watkins and the Young Gas Storage (Young Storage) facility in the Front Range of Colorado to expand CIG's capacity and establish six new services utilizing the new transportation and storage capacity.[202] The lateral on the project from Watkins to Young Storage will be adjacent to CIG's existing mainline; the lateral on the project from Cheyenne to a location on the Watkins-Young lateral will not be adjacent to the existing mainline from Cheyenne to Watkins. (On June 27, 2008, CIG asked the FERC to allow CIG to make an upward revision in the incremental transportation rates that will apply to the Project.)

a. Bundled Storage-Transportation Service

CIG proposed to offer firm unbundled storage service (Rate Schedule FS-Y), interruptible storage (Rate Schedule IS-Y), and an hourly balancing service that relies on a bundling of CIG transportation capacity and Young Storage capacity pursuant (Rate Schedule TSB-Y).[203] In order to provide these services, CIG proposed to acquire capacity on Young Storage by acquiring Young Storage capacity from Public Service Company of Colorado (PSCo), which is a large gas utility in the Denver, Colorado area. Windy Hill Storage (Windy Hill) argued that this bundling of Young Storage capacity, and CIG transportation capacity, gives CIG an unfair competitive advantage over Windy Hill and other storage companies. The FERC rejected this argument. The FERC said that CIG's proposal to acquire capacity on Young Storage is consistent with the FERC's policy of allowing a pipeline to acquire capacity on another pipeline.[204] The FERC said that although it does require a pipeline to offer services on an unbundled basis, the FERC allows a pipeline to offer additional services that involve bundling if this provides increased flexibility to customers. The FERC cited no-notice service and enhanced hourly flow service as examples where bundling of transportation and storage is allowed. The FERC said that the TSB-Y hourly balancing service is similar to the bundled service that the FERC has previously authorized.[205] The FERC also noted that CIG developed TSB-Y service in response to PSCo's need for access to gas supply on short notice in order to serve PSCo's gas-fired generation in conjunction with wind power currently being developed.

202. *Colorado Interstate Gas Co.*, 122 F.E.R.C. ¶ 61,256 (2008).
203. *Id.* at P 68.
204. *Id.* at P 76.
205. *Id.* at P 37.

b. Interconnections with CIG Storage

Windy Hill argued that CIG's plan to construct interconnections on High Plains with CIG affiliate Young Storage and CIG's proposed Totem Storage Project (Totem) would give Young and Totem an unfair competitive advantage over Windy Hill. CIG replied that Windy Hill never asked that High Plains construct a tap with Windy Hill, and that CIG would review such a request when and if High Plains submits the request. The FERC agreed. The FERC pointed to its so-called *Panhandle* policy of requiring a pipeline to construct (though not necessarily pay for) an interconnection sought by a party if the following conditions are satisfied:

> the party seeking the interconnection must be willing to bear the cost of construction of the interconnection;(2) the proposed interconnection must not adversely affect the pipeline's operations;(3) the proposed interconnection and resulting transportation must not diminish service to the pipeline's existing customers;(4) the proposed interconnection must not cause the pipeline to be in violation of any applicable environmental or safety laws or regulations with respect to the facilities required to establish an interconnection with the pipeline's existing facilities; and(5) the proposed interconnection must not cause the pipeline to be in violation of its right-of-way agreements or any other contractual obligations with respect to the interconnection facilities.[206]

The FERC said that this "Open Tap" policy means that if Windy Hill asks CIG to interconnect the Windy Hill facility with High Plains, and these five Open Tap conditions are satisfied, CIG must allow the interconnection. The FERC said that CIG can agree to bear some or all of the costs of the interconnection where it reasonably determines there are shipper commitments and charges that provide an adequate economic basis for the connection or otherwise creates commercial opportunities or other benefits for CIG's operations.[207]

c. Incremental Rates

The proposed incremental maximum tariff reservation rate for firm transportation on the High Plains Expansion Project (Rate Schedule TF-HP) is 3.7271 dollars per Dth, and the proposed commodity recourse rate is 0.0012 dollars per Dth (Sixth Revised Sheet No. 7A), resulting in a 100 percent load factor incremental recourse rate on the High Plains Expansion Project of 0.1238 dollars per Dth.[208] The Indicated Shippers protested these rates because they are significantly lower than the maximum tariff rate applicable to Existing System. The Existing System recourse reservation rate for firm transportation (Rate Schedule TF-1) is 9.6477 dollars per Dth, and the recourse commodity rate is 0.0170 dollars per Dth resulting in an existing 100 percent load factor rate of 0.3344 dollars per Dth.[209] The Indicated Shippers argued that the FERC's policy is that a pipeline must apply its existing maximum applicable Part 284[210] rate as

206. *Id.*
207. *Id.* at P. 78.
208. *Id*. at P. 46.
209. *Id*. at P. 64.
210. *Id.*

the initial recourse rate for an expansion if the calculated recourse rate is less than the Part 284 rate. The Indicated Shippers said that this policy applies with special force here because High Plains will essentially be an operational loop of CIG's mainline from Cheyenne to Watkins.[211]

The FERC rejected the Indicated Shippers' arguments, and approved the proposed incremental rates.[212] The FERC said that its policy is that an expansion must rely on the pipeline's existing transportation rate but only if the expansion will be operationally integrated with the pipeline's existing system.[213] The FERC determined that High Plains will not be integrated with CIG's system. The FERC noted that High Plains will not use any existing pipeline segment on CIG's mainline system and there are no interconnections between the facilities that would allow gas to flow from one system to another.[214] The FERC also noted that the existing compression facilities on CIG's mainline system will not be used to effectuate High Plains' receipts and deliveries.[215] Instead, the operation of the High Plains system will be driven by the pressure supplied by the interconnecting pipelines, whether from the compression of Rockies Express, WIC or Cheyenne Plains at the Cheyenne Hub or from the storage facilities of Young Storage. The FERC noted that the only interrelationship between High Plains and CIG's existing system is the Watkins air blending facilities which will be utilized to meet certain gas quality standards. But, the FERC pointed out that these air blending facilities are incrementally priced to existing shippers and will also be incrementally priced to High Plains' shippers that use the air blending facilities. The FERC also noted that High Plains' shippers will pay the fuel associated with the use of the air blending facilities. The FERC said that this means that both CIG's existing and expansion shippers will be responsible for their proportional share of the costs of the air blending facilities.[216] The FERC also rejected the Indicated Shippers' argument that PSCo will decontract its capacity on CIG's existing system to obtain the much cheaper capacity on High Plains. The FERC said that this allegation is speculative, and that if decontracting occurs, CIG would have to file a rate case to try to shift costs to remaining shippers.[217]

2. REX-East

On May 30, 2008, the FERC authorized Rockies Express to construct the 639-mile segment of its system that will extend from an interconnection with Panhandle Eastern Pipe Line (PEPL) in Audrain, Missouri to an interconnection with Dominion Transmission, Dominion East Ohio, and Texas Eastern Transmission, at the Clarington Hub in Monroe County, Ohio (the so-called REX-East segment).[218] REX-East will have capacity of 1,800,000 Dth/d day,

211. *Id.*
212. *Id.*
213. *Id.*
214. *Id.*
215. *Id.* at P 37.
216. *Id.*
217. *Id.* at P. 64.
218. *Rockies Express Pipeline, LLC*, 123 F.E.R.C. ¶ 61,234 (2008).

and will constitute Zone 3 of the Rockies Express pipeline system.[219] (Two upstream segments of the Rockies Express system are already in-service: (1) the Entrega segment (which extends northerly from Meeker to Wamsutter and then easterly to Cheyenne);'[220] and (2) the REX-West segment (which extends from Cheyenne to PEPL-Audrain)).[221] Rockies Express is a Delaware Limited Liability Company that is wholly owned by West2East Pipeline, LLC (West2East) but is managed by a Board of Managers that includes Managers of West2East and Alenco Pipelines, Inc. Kinder Morgan W2E Pipeline, LLC (KMW2E), which is an indirect wholly-owned subsidiary of Kinder Morgan Energy Partners, L.P., has a fifty-one percent ownership interest in West2East. P&S Project I, a wholly owned subsidiary of Sempra Global, of which Sempra Energy is the sole shareholder, has a twenty-five percent ownership interest. COPREX, LLC, a wholly owned subsidiary of ConocoPhillips Company, has a twenty-four percent ownership interest, but this ownership interest will increase by one percent to twenty-five percent when REX-East is completed; KMEP's interest will then drop by one percent to fifty percent.[222] (On June 27, 2008, Murray Energy Corporation, Consolidated Land Company, and American Energy Corporation jointly filed a rehearing request that asks FERC to clarify that the impact of the construction and operation of the REX-East on the Petitioners' coal mine operations must be addressed by REX-East in complying with the environmental conditions imposed by FERC in the certificate.)[223]

a. Interconnections With Other Pipelines

MoGas, an interstate pipeline in Missouri, argued that Rockies Express acted in an unduly discriminatory manner by refusing to pay for the construction of an interconnection with MoGas, even though Rockies Express paid for interconnections with several other pipelines, including Rockies Express affiliate Natural Gas Pipeline Company of America (NGPL).[224] The FERC rejected this argument, and said that:

> [i]n developing a project to serve new markets or increase service to existing markets, a pipeline applicant is required to advertise the availability of capacity on its contemplated project via an open season. The open season is designed to alert all interested shippers that they may subscribe to capacity on the contemplated facilities." "Once potential shippers have come forward, it is expected that the pipeline will work with the shippers to determine the design of the facilities to meet the market demand for the project." "However, a pipeline applicant is free to develop, design, and propose a new pipeline project as it sees fit with the knowledge that the [FERC] must find its proposals to be in the public convenience and necessity under the NGA before construction can commence.
>
> In the development of the Rockies Express system, MoGas did not participate in the open season held for the REX-West and REX-East projects, nor did the shippers on

219. *Id*. at P. 8.

220. 112 F.E.R.C. ¶61,191 (2005), *order on reh'g*, 114 F.E.R.C. ¶61,326 (2006).

221. *Preliminary Determination on Non-Environmental Issues*, 116 F.E.R.C. ¶61,191 (2006), *order issuing certificate*, 119 F.E.R.C. ¶61,069 (2007).

222. 123 F.E.R.C. ¶ 61,234 at P 3.

223. *Id.*

224. *Id.*

> MoGas' system request service from Rockies Express during the open season." "As a result, Rockies Express states that it did not propose an interconnection with MoGas as part of its project.[225]

The FERC observed that "[n]o shipper requested an interconnection between Rockies Express and MoGas during the open season and inclusion of the costs of a MoGas interconnection in Rockies Express' rates would result in those costs being borne by all shippers when no shipper uses the interconnection."[226] The FERC said that, instead, "Rockies Express sought authority to construct five interconnections on the REX-West project and 19 interconnections on the REX-East project because shippers requested service at these points and the costs of the interconnections necessary to serve these shippers are reflected in the rates those shippers will pay for service on Rockies Express."[227] The FERC said that:

> [s]ince it has not been demonstrated that a MoGas interconnection would provide an actual benefit to any interested shipper or to the system as a whole, we see no justification for inclusion of the costs in the system rates, or requiring Rockies Express to pay for such an interconnection. Under the circumstances presented here, we find that Rockies Express did not discriminate against MoGas.[228]

The FERC also rejected the argument by MoGas that Rockies Express favored its affiliate by proposing an interconnection with Natural Gas Pipeline Company of America (Natural). The FERC said that:

> [b]eyond the described physical differences between the Natural and MoGas systems, a Rockies Express shipper requested an interconnection between Natural and Rockies Express." "No shipper requested an interconnection between MoGas and Rockies Express." Further," although Natural has a lateral that serves some customers south and east of St. Louis, there is no evidence in the record that suggests that Rockies Express denied an interconnection with MoGas so that its affiliate could obtain a competitive advantage with MoGas.[229]

b. Roll-In

The FERC approved the unopposed request by Rockies Express for a predetermination that Rockies Express may roll-in as part of the recourse rates for Zones 1 and 2 the cost of the two compressors in the REX-East segment (the Arlington and the Bertrand Compressor Stations). The FERC said that:

> the two compressor facilities will serve to optimize the reliability and efficiency of Rockies Express' certificated facilities and will benefit shippers by providing increased flexibility...." "The incremental costs of the facilities are less than the revenues generated on the new contract capacity created by the addition of the two compressor stations.[230]

The FERC said that this positive cash flow associated with the two compressors means that "no shipper will subsidize the roll in of these costs."[231]

225. *Id.*
226. *Id.* at P. 47.
227. *Id.*
228. *Id.*
229. *Id.*
230. *Id.* at P 59.
231. *Id.* at P 60.

3. Guardian Pipeline

The Guardian G-II Expansion project filed for a the FERC certificate in October 2006. This project consists of 119.2 miles of twelve to thirty inch pipeline running from Ixonia to Green Bay, Wisconsin, along with 39,000 horsepower of compression, and is designed to move up to 437,200 MMBtu per day.[232] Other elements of the project on Guardian's existing G-I system include two 39,000 horsepower compression stations (78,000 total), seven new meter stations, and additional facilities to transport an additional 537,200 MMBtu per day from Joliet, Illinois to Ixonia, Wisconsin. Shippers include Wisconsin Public Service Corporation, Northern Natural Gas, and Wisconsin Gas.[233]

A final Environmental Impact Statement (EIS) was issued on October 26, 2007, and a final certificate was issued on December 14, 2007.[234] Construction began in March 2008, and the expected in-service date is November 2008. Northern Plains Natural Gas Company, LLC manages the construction of the project. ONEOK Partners, LP owns Guardian Pipeline, LLC and ONEOK Partners GP, LLC operates Guardian Pipeline.

4. Transwestern Pipeline Company, LLC

Transwestern submitted a certificate application for the Phoenix Expansion Project on September 15, 2006. This project proposes to expand the Transwestern system by constructing twenty five miles of thirty-six-inch diameter pipeline that will loop Transwestern's existing San Juan Lateral in New Mexico, and 259 miles of thirty-six-inch and forty-two-inch diameter pipeline that will interconnect the existing Transwestern mainline with the existing East Valley Lateral in Coolidge, Arizona.[235] In addition, Transwestern would purchase a portion of El Paso's ownership interest in the East Valley Lateral.[236] This project is designed to transport 500,000 MMBtu per day from Ash Fork, Arizona, to the markets in central and southern Arizona.[237]

The Town of Buckeye, Arizona, and others, filed a series of motions in opposition to the construction of this pipeline stating that the information presented by Transwestern was insufficient and that the pipeline impact analysis lacked rigor.[238] The FERC rejected these arguments and issued a certificate for the Phoenix Expansion Project on November 15, 2007, deeming it environmentally acceptable if built and operated in accordance with the environmental mitigation measures recommended in the EIS.[239]

Requests for rehearing and reconsideration were filed by Buckeye on December 17, 2007. On December 20, 2007, Buckeye filed a motion to stay construction of part of the new pipeline, arguing that it would cause irreparable

232. *Guardian Pipeline, LLC*, 121 F.E.R.C. ¶ 61,259 (2007).

233. *Id.*

234. *Id.* at P 1.

235. *Id.* at P 46.

236. *Transwestern Pipeline Co., LLC,* 121 F.E.R.C. ¶ 61,175 (2007).

237. *Id.*

238. *Transwestern Pipeline Co., LLC & El Paso Nat.Gas Co.*, 121 F.E.R.C. ¶ 61,175 (2007); *Transwestern Pipeline Co., LLC & El Paso Nat. Gas Co.*, 122 F.E.R.C. ¶ 61,165 (2008).

239. 121 F.E.R.C. ¶ 61,175 (2007).

harm to local development interests.[240] Oppositions to the Buckeye motion were filed by Transwestern, Salt River Project, Southwest Gas, and Arizona Public Service on January 4, 2008. On February 21, 2008, the FERC denied both the request for rehearing and motion to stay.[241] As of June 2008, the Phoenix Expansion Project is under construction. Partial authorization to begin service on the San Juan loops and operate the Bloomfield compressor was granted on July 2, 2008.[242]

5. Texas Gas Transmission

On July 11, 2007, Texas Gas filed a certificate application with the FERC for the Fayetteville/Greenville Expansion (Fayetteville) project.[243] Fourteen motions to intervene were filed and granted. Memphis, Light, Gas and Water was concerned that Texas Gas's proposed rates could result in an under collection of costs, and that under collected costs might be passed on to current shippers. The Fayetteville project includes:

Expansion of the existing Texas Gas system through the construction about 166 miles of 36-inch diameter pipeline in Faulkner, Cleburne, White, Woodruff, St. Francis, Lee, and Philips Counties, Arkansas, and Coahoma County, Mississippi (Fayetteville Lateral);

96.4 miles of 36-inch diameter pipeline in Washington, Sunflower, Humphreys, Holmes, and Attalla Counties, Mississippi (Greenville Lateral);

0.8 mile of 36-inch diameter tie-in lateral; and

0.4 mile of 20-inch diameter tie in lateral in Attalla County, Mississippi.[244]

In addition, a 10,650 horsepower compressor station is proposed in Atalla County, Mississippi, along with related above-ground facilities along both laterals.

The purpose of this project is to provide additional take-away capacity for gas produced in the Fayetteville Shale production area in north-central Arkansas for eventual delivery to Henry Hub, and the market areas in the Midwest and Northeast. The new capacity will be approximately 1,200,000 MMBtu per day for the Fayetteville Lateral and 1,000,000 MMBtu per day for the Greenville Lateral.[245] Texas Gas proposed an incremental rate treatment for service on the laterals.

On May 2, 2008, the FERC issued an order certificating the project, and affirmed that it would closely scrutinize all future filings to ensure that existing shippers do not subsidize any under-collected costs.[246] The first sixty miles of the Fayetteville Lateral are planned to be in service in the third quarter of 2008, and the rest of the pipeline targeted to be in service during the first quarter of 2009.

240. *Id.*

241. 122 F.E.R.C. ¶ 61,165 (2008).

242. TRANSWESTERN PIPELINE COMPANY, LLC, PROJECT STATUS REPORT: PHOENIX EXPANSION PROJECT, at 1 (June 20, 2008) http://www.energytransfer.com/docs.

243. *Texas Gas Transmission, LLC*, 123 F.E.R.C. ¶ 61,118 (2008).

244. *Id.*

245. *Id.*

246. *Id.*

6. Gulf Crossing Pipeline Company

Gulf Crossing applied for FERC certification on June 19, 2007.[247] The purpose of this project is to provide an outlet for significant volumes of new gas production from the Barnett Shale, Caney Woodford Shale, and other production areas in Texas and Oklahoma. Eighteen motions to intervene were filed and granted. On February 19, 2008, Hall-Williams, LLC, filed a motion to intervene out-of-time and a protest requesting that the FERC deny Gulf Crossing's application.[248] Hall-Williams owns a fifty percent interest in land that Gulf Crossing is planning to build a part of its pipeline. The two parties were in negotiations to produce a right-of-way agreement, but Gulf Crossing brought the matter to Louisiana State Court, at which point Hall-Williams filed its motions. The FERC denied Hall-Williams's motions, as they were not filed in a timely manner.[249] The FERC issued a certificate for the pipeline on April 30, 2008.[250] The expected in-service date for this pipeline is the first quarter of 2009. Gulf Crossing is a wholly-owned subsidiary of Boardwalk Pipeline Partners, LP.[251]

Gulf Crossing consists of 357 miles of forty-two-inch pipe with a capacity of 1,400,000 MMBtu per day, beginning near Sherman, Texas, and ending at Perryville, Louisiana.[252] The end markets of this pipeline are expected to be the Midwest, Northeast, Southeast, and Henry Hub. The key shippers of this pipeline will be Crosstex Gulf Coast Marketing, Ltd., Devon Gas Services, LP, and Enterprise Gas Marketing, LP. Gulf Crossing will charge an incremental, cost-based rate for service on the system.

B. Storage Projects

1. Steckman Ridge, LP

On November 1, 2007, Steckman Ridge filed an application pursuant to Section 7(c) of the NGA[253] for a certificate of public convenience and necessity authorizing the construction and operation of a natural gas storage facility (Steckman Ridge Project) in Bedford County, Pennsylvania.[254] Steckman Ridge requested authority to charge market-based rates for the proposed storage services, and waiver of certain FERC filing, accounting, and reporting requirements applicable to cost-based rate proposals, which the FERC has previously found inapplicable for storage providers granted market-based rate authority. Steckman Ridge's market power analysis included LNG supply and local production. On June 5, 2008, the FERC issued an order granting Steckman Ridge's requested certificates for its proposed storage project and services and its request to charge market-based rates for its services.[255]

247. *Gulf Crossing Pipeline Co., LLC,* 123 F.E.R.C. ¶ 61,100 (2008).
248. *Id.*
249. *Id.*
250. *Id.*
251. *Id.*
252. *Id.*
253. *Steckman Ridge, LP*, 123 F.E.R.C. ¶ 61,248 (2008).
254. *Id.*
255. *Id.*

Generally, the FERC evaluates applicants' requests for market-based rate authority for storage services under the analytical framework of its 1996 Alternative Rate Policy Statement (Rate Policy Statement).[256] Under the Rate Policy Statement, the FERC will approve market-based rates for storage providers where the applicant has demonstrated it lacks market power or has adopted conditions that significantly mitigate market power.[257] The FERC has approved requests to charge market-based rates for storage services based on a finding that the applicants would not be able to exercise market power due to small size, anticipated share of the market, and numerous competitors.[258] As noted above, pursuant to Order No. 678, the FERC now permits storage applicants to include non-storage products and services, including pipeline capacity and local production and LNG supply in the calculation of its market concentration and market share.

The FERC has stated that, to be a good alternative, the alternative must be comparable in terms of availability, quality and price.[259] In adopting a more expansive definition of the relevant product market for storage in Order No. 678, the FERC specifically recognized that local production can be a substitute for gas storage services.[260] In its application, Steckman Ridge asserted that local production in the Greater Mid-Atlantic Market area meets all three of the FERC's requirements for a good alternative. Steckman Ridge stated that the quality of local production is identical to storage because both services provide an identical unit of natural gas at the same point in time.[261] Steckman Ridge stated that all local production that is not under contract for more than one year and is sold in the relevant geographic market during a peak period can be considered to be readily available.[262] Steckman Ridge further stated that most of the local production in this area is held by marketers who, in turn, sell to end users under short-term (usually month-to-month) contracts, although some end users, such as local distribution companies, may hold contracts for longer

256. *Alternatives to Traditional Cost-of-Service Ratemaking for Natural Gas Pipelines and Regulation of Negotiated Transportation Services of Natural Gas Pipelines*, 74 F.E.R.C. ¶ 61,076 (1996); *Regulation of Negotiated Transportation Services of Natural Gas Pipelines*, 74 F.E.R.C. ¶ 61,194 (1996) *reh'g & clarification denied*, 75 F.E.R.C. ¶ 61,024 (1996), *petitions denied & dismissed*, *reh'g denied*, 75 F.E.R.C. ¶ 61,066 (1996); Burlington Resources Oil & Gas Co. v. FERC, 172 F.3d 918 (D.C. Cir. 1998) (Rate Policy Statement)*;* Final Rule, *Rate Regulation of Certain Natural Gas Storage Facilities*, 71 Fed. Reg. 36,612 (2006) F.E.R.C. STATS. & REGS., ¶ 31,220 (2006); Order No. 500, *Rate Regulation of Certain Natural Gas Storage Facilities*, [Regs. Preambles 2006-2007] F.E.R.C. STATS & REGS. ¶ 31,220 (2006) (to be codifed at 18 C.F.R. pt. 284); Order No. 678-A, *Rate Regulation of Certain Natural Gas Storage Facilities*, 117 F.E.R.C. ¶ 61,190 (2006), *order on clarification and reh'g*.

257. Order No. 678, *Rate Regulation of Certain Natural Gas Storage Facilities*, [Regs. Preambles 2006-2007] F.E.R.C. STATS & REGS., ¶ 30,407.

258. *Egan Hub Partners, LP*, 99 F.E.R.C. ¶ 61,269 (2002); *Moss Bluff Hub Partners, LP*, 80 F.E.R.C. ¶ 61,181 (1997).

259. *Alternatives to Traditional Cost-of-Services Ratemaking for Natural Gas Pipelines & Regulation of Negotiated Transportation Services of Natural Gas Pipelines*, 74 F.E.R.C. ¶ 61,076 at 61,231 (1996).

260. Order No. 678, *Rate Regulation of Certain Natural Gas Storage Facilities*, [Regs. Preambles 2006-2007] F.E.R.C. STATS & REGS., ¶ 30,407.

261. *Steckman Ridge, LP*, 123 F.E.R.C. ¶ 61,248 (2008).

262. Steckman Ridge used Energy Information Administration (EIA) data on local natural gas production by state.

periods.[263] To be conservative, Steckman Ridge stated that it only considered seventy-five percent of the local production to be readily available.

Steckman Ridge stated that local production is a commodity, whereas storage is a transportation service provided over time.[264] Therefore, in determining whether local production is a good alternative to storage, the "time dimension" implicit in local production (*i.e.*, providing gas at peak rather than at off-peak) must be analyzed.[265] Steckman Ridge stated that local production meets the price comparability for a good alternative if the peak-price premium for local production is less than or equal to the price of storage plus ten percent.[266] Steckman Ridge calculated the peak-price premium to be 6.85 dollars per Mcf. Steckman Ridge then calculated the threshold price for storage to be 10.37 dollars per Mcf using the cost-of-service rate for Dominion, the largest storage provider in the region.[267] Since the 6.85 dollars per Mcf peak-price premium for local production is less than the 10.37 dollars per Mcf threshold price of storage, local production is price-comparable to storage.[268] Therefore, Steckman Ridge asserted that the local natural gas production meets the availability, quality, and price requirements for a good alternative.[269]

The June fifth order found that Steckman Ridge's analysis demonstrated that its proposed storage facilities will be in a highly competitive area where numerous storage service alternatives exist for potential customers.[270] The FERC also found that Steckman Ridge's prospective market shares were low and that the market area HHIs of Steckman Ridge and its affiliates were mitigated by Steckman Ridge's small market share, the availability of competing services, the fact that Steckman Ridge's affiliate storage fields are subject to FERC-approved cost-based rates, and the fact that Steckman Ridge's entry will increase the storage alternatives in the Greater Mid-Atlantic Market area.

2. Texas Gas Transmission, LLC

On June 25, 2007, Texas Gas filed an application seeking authority to abandon certain facilities and expand in two phases its facilities at Midland Gas Storage Field in Muhlenberg County, Kentucky (Midland Field).[271] Texas Gas also seeks authorization to provide storage service through the expanded facilities at market-based rates. The project would provide up to 8.25 Bcf of new firm storage capacity and up to 92.2 MMcf per day of increased firm deliverability.[272] Texas Gas proposes to place the facilities into service under a phased approach, with the facilities necessary to provide 5.31 Bcf of firm storage capacity for two identified expansion shippers going into service on November

263. 123 F.E.R.C. ¶ 61,248.

264. *Id.*

265. *Steckman Ridge, LP*, 123 F.E.R.C. ¶ 61,248 (2008).

266. Steckman Ridge states that the FERC uses a ten percent threshold price increase to identify good alternatives. 74 F.E.R.C. at ¶ 61,076.

267. 123 F.E.R.C. ¶ 61,248 (2008).

268. *Id.*

269. *Texas Gas Transmission, LLC*, 122 F.E.R.C. ¶ 61,190 (2008).

270. *Id.*

271. *Id.*

272. *Id.*

1, 2008, and with all facilities necessary for the entire 8.25 Bcf of storage capacity in service by November 1, 2009.[273] If the FERC denies market-based rate authority, Texas Gas proposes to construct only the facilities required to provide 5.31 Bcf of firm storage capacity under cost-based rates. On February 29, 2008, The FERC issued an order finding that Texas Gas meets the requirements for market-based rate authority under Section 4(f) of the NGA.[274] Accordingly, the FERC granted Texas Gas' request for market-based rate authority under Section 4(f) of the NGA.[275]

In Order No. 678, the FERC promulgated rules to implement new Section 4(f) of the NGA to permit underground natural gas storage service providers that are unable to show that they lack market power to negotiate market-based rates.[276] Specifically, Order No. 678 requires that underground natural gas storage providers must meet the following criteria in order to negotiate market-based rates: (1) the capacity enabling provision of the service must relate to a "specific facility" requiring construction which is placed in service after the date of the Energy Policy Act of 2005 (EPACT 2005), be it a new storage cavern or a facility that expands capacity at an existing cavern or reservoir;[277] (2) the market-based rates must be in the public interest and necessary to encourage the construction of storage capacity in the area needing storage services; and (3) customers must be adequately protected. The February 29, 2008, order stated that the FERC was considering Texas Gas' proposed project with respect to the specific requirements for market-based rate authority pursuant to NGA Section 4(f).[278]

The order noted that under Order No. 678, an applicant can demonstrate that storage services are needed in the area by including evidence of the following circumstances: (1) general lack of storage in the area, (2) full utilization of existing storage capacity, (3) pipeline constraints in the area, and (4) projected increased demand for natural gas in the area to be served. The FERC found all of these factors are present in the Texas Gas case.[279]

The FERC's Staff Storage Report estimates that sixty Bcf of incremental working gas capacity will be needed in the Midwest by 2020.[280] Moreover, Texas Gas' existing storage capacity, including its two previous expansion projects, is fully contracted and Texas Gas indicates that it was the receipt of requests for additional firm storage that prompted its consideration of another expansion of its storage capacity. The order stated that there are also pipeline constraints in Texas Gas' area of operation. The placement of the storage facilities, including the looping, could act to mitigate the impacts of pipeline

273. *Id.*

274. 15 U.S.C. § 717(f) (2000).

275. *Id.*

276. *Id.*

277. Order No. 678, *Rate Regulation of Certain Natural Gas Storage Facilities,* [Regs. Preambles 2006-2007] F.E.R.C. STATS. & REGS., ¶ 30,407 at P 115 (2006) (codified at 18 CFR pt. 284).

278. 122 F.E.R.C. ¶ 61,190 (2008).

279. *Id.*

280. FEDERAL ENERGY REGULATORY FERC, STAFF REPORT: CURRENT STATE OF AND ISSUES CONCERNING UNDERGROUND NATURAL GAS STORAGE at p. 15 (Sept. 30, 2004), http://www.ferc.gov/legal/staff-reports.asp.

constraints into the Texas Gas market. Given these factors, the FERC found that there is a demonstrated additional need for natural gas storage in the area to be served by Texas Gas' proposed project.[281]

Regarding the requirement that an applicant show that the facilities would not be built but for market-based rate treatment, Texas Gas maintained there is not sufficient demand under long-term contracts for the proposed storage services at cost-based or negotiated rates to justify Texas Gas making the substantial investment required for the full 8.25 Bcf increment of capacity proposed in this case.[282]

> Texas Gas [stated] that given the fact that this project is not fully subscribed, it would not have an opportunity to earn a fair return on its investment under cost-based rates because it would be forced to discount its rates for service when the market value of its capacity is below the maximum cost-based rate, yet it could not charge above its maximum cost-based rate even when the market value of its storage capacity rises above that level. However, under market-based rates, Texas Gas states it would be willing to incur the costs associated with constructing its full increment of proposed storage capacity and enter into shorter-term contracts based upon current market conditions.[283]

"[T]he FERC found that market-based rates are necessary to encourage Texas Gas to construct the entire 8.25 Bcf of storage capacity proposed."[284]

The final requirement for obtaining market-based rate authority under NGA section 4(f) is that customers will be adequately protected. The FERC found that "Texas Gas' open season, which included an incremental cost-based reserve price for the proposed storage capacity, provided adequate protection for the potential storage customers that ultimately signed binding precedent agreements for capacity."[285] Regarding protections for those customers that may subsequently seek service using that portion of the proposed expansion not currently subscribed (or expansion project capacity which may become available in the future, *e.g.*, upon expiration of the initial service agreements), Texas Gas has stated that it will post all available market-based storage capacity on its website. Texas Gas also proposed to add tariff provisions that would allow it to sell its storage capacity through interactive auctions that it contends would prevent withholding of capacity, price discrimination, or favoritism.

> Texas Gas states that its proposed auction adheres to the principles for creating an auction outlined in Order No. 637. These principles include: (i) notification of auction; (ii) predictable timing; (iii) open to all bidders on non-discriminatory basis; (iv) user-friendly with accessible rules; (v) full disclosure prior to auction of procedures for bidding and selecting winning bid; (vi) no favoritism in selecting winning bid, including monitoring of the application of selection criteria and methods for verifying reserve price; and (vii) disclosure of transaction information, including prices and volumes.[286]

"[O]ne concern the FERC had... regarding the protection of Texas Gas' cost-based rate customers involved Texas Gas' proposal to offer a new market-

281. *Id.*
282. *Texas Gas Transmission, LLC*, 122 F.E.R.C. ¶ 61,190 at P 62, 105 (2008).
283. *Id.*
284. *Id.* at P 62,107.
285. *Id.* at P 62,106.
286. *Id.*

based rate interruptible storage service from the incremental capacity in addition to its existing cost-based interruptible storage service."[287] "The FERC found, this aspect of Texas Gas' proposal to be unclear,... and required... Texas Gas to file... an explanation of how the offer of market-based interruptible storage service will be made in such a way as to ensure the protection of cost-based interruptible storage service customers."[288] The FERC order also found that Texas Gas' auction proposal was not clear on how a reasonable reserve price would be set to ensure that capacity will not be withheld and that customers will be protected. Accordingly, Texas Gas was directed to file information clarifying how its auction process will work for both excess capacity being marketed by Texas Gas and upon customer request.[289]

C. LNG Projects

1. Projects Receiving FERC Authorization

a. Broadwater Energy, LLC

On March 20, 2008, the FERC approved applications of affiliates Broadwater Energy, LLC and Broadwater Pipeline, LCC (collectively "Broadwater") under sections 3 and 7(c) of the NGA.[290] Broadwater sought to site, construct, and operate a floating storage and regasification unit (FRSU) LNG import terminal and associated facilities approximately nine miles off the coast of Long Island in Long Island Sound. It further proposed to construct, own, and operate a 21.7 mile long, thirty-inch diameter pipeline from the outlet of the FSRU to a subsea interconnection with the Iroquois Gas Transmission System. The proposed facilities would deliver up to 1.25 Bcf per day.[291] The terminal and associated pipeline are intended to provide a new source of reliable, long-term, and competitively priced natural gas to the Long Island, New York City, and Connecticut markets by connecting to the existing interstate pipeline system.

Based on its review of the facts, the FERC approved the project despite significant opposition from state and local government agencies, some public officials, local environmental organizations, and individuals that has expressed concerns about safety, security, environmental impacts, impacts upon local recreational and commercial uses, and visual impacts. Project opponents' concerns were considered and disposed of by the FERC in a lengthy final Environmental Impact Statement (EIS) issued on January 11, 2008.[292]

The FERC agreed with the conclusions presented in the final EIS that (subject to adoption of more than eighty mitigation measures specified in the EIS) construction and operation of the Broadwater Project would result in only

287. *Id.*

288. *Id.*

289. *Id.* at P 62, 102.

290. *Broadwater Energy, LLC&d Broadwater, Pipeline, LLC*, 122 F.E.R.C. ¶ 61,255 (2008); 15 U.S.C. § 717 (2007).

291. *Id.*

292. *Id.* at P 2.

limited adverse environmental impacts. The FERC's review considered numerous environmental, safety and security factors as well as facility alternatives (*e.g.*, alternative energy sources, six existing and seven new proposed pipelines that now serve or could serve the target market, and twenty other LNG terminals). The FERC concluded that the project is necessary in order to meet the projected energy needs for the New York City, Long Island, and Connecticut markets.[293]

The FERC's approval was conditioned on the requirement that Broadwater ensure that its marine terminal and related vessel traffic comply with all United States Coast Guard requirements so that necessary risk mitigation measures are in place during operation.[294] The FERC documented the Coast Guard findings that the remoteness of the project from population centers would provide the terminal with safety and security benefits, and for similar reasons found that any risks arising from the LNG carrier operations would also be low.[295] The Coast Guard findings proposed a fixed safety and security zone around the terminal with a radius of 1,210 yards, centered on the pivoting FSRU from which vessels not related to the project would be prohibited from entering without Coast Guard permission.[296] The FERC noted, however, that this security zone would infringe upon some of the territory of area fisherman consequently excluding the fishermen from the fishing areas within the security zone. Broadwater has proposed compensating the fisherman for such economic impact. It also established a Fisheries Advisory Committee to work with any affected fisherman.[297]

With regard to the impacts of the terminal upon water use and fisheries, the National Marine Fisheries Service (NMFS) found only minor impacts. NMFS filed comments on the final version of the EIS that included nineteen essential fish habitat recommendations. While many of the recommendations were already included elsewhere in the proceedings, Broadwater agreed to adopt all of the recommended mitigation measures.[298]

Some government agencies that had not intervened prior to the FERC's order sought to participate to file requests for rehearing and other parties also sought rehearing. Both the belated interventions, and the requests for rehearing, have been opposed by Broadwater. On May 5, 2008, the FERC issued an order granting rehearing for further consideration, but to date has not yet issued an order on the rehearing requests on the merits.

b. Calhoun LNG, LP

On September 20, 2007, the FERC granted authorization under NGA section three for Calhoun LNG, LP (Calhoun) to site, construct and operate an LNG import terminal and associated facilities at the Port of Port Lavaca-Point

293. *Id.*
294. *Id.* at PP 49-50.
295. *Id.* at PP 52-53.
296. *Id.* at P 56.
297. *Id.* at PP 59-60.
298. *Id.* at P 72.

Comfort in Calhoun County, Texas.[299] The project is designed for an installed gas send-out capacity of 1.0 Bcf per year with the capability of regasifying LNG for send-out and delivery into the intrastate and interstate natural gas pipeline grid.[300] The FERC also granted authorization under NGA section 7(c) for Point Comfort Pipeline Company, L.P. (Point Comfort), a Calhoun affiliate, to construct and operate 27.1 miles of new pipeline (the Point Comfort Pipeline) to transport the gas from the tailgate of the proposed Calhoun LNG terminal to various interstate and intrastate pipelines – Florida Gas Transmission Company, Gulf South Pipeline Company, L.P, Natural Gas Pipeline of America, Transcontinental Gas Pipe Line Corp, and Tennessee Natural Gas Company.[301]

The FERC concluded that, subject to the conditions imposed in the order, Calhoun's proposed LNG terminal is not inconsistent with the public interest[302] and that Point Comfort's proposal was required by the public convenience and necessity.[303]

The FERC approved Point Comfort's proposed cost of service and initial rates,[304] as well as other rate proposals, but also imposed a number of requirements on rates, various tariff provisions, and accounting treatment. The FERC concluded that, if all laws and regulations, proposed mitigation efforts, and recommendations are followed, the construction and operation of the proposed facilities would be an environmentally acceptable action that would be unlikely to result in significant adverse environmental impacts.[305] The FERC required Calhoun and Point Comfort to undertake various environmental measures, including the implementation of a plan to minimize soil erosion and enhance revegetation of disturbed areas.[306] The FERC also required Calhoun to address several design issues before either initial site preparation, before construction after final design, before commissioning, or before commencement of service.[307] Calhoun was further required to develop an emergency response plan and to coordinate procedures with the Coast Guard.[308]

c. Southern LNG, Inc.

On September 20, 2007, The FERC granted a number of authorizations to several entities related to LNG facilities on Elba Island, Georgia.[309] In an April 4, 2007, order, the FERC issued a preliminary determination addressing only the non-environmental issues raised by the applications filed by Southern Natural Gas Company (Southern) and Elba Express Company, LLC (Elba Express) under NGA section seven, requesting certificate authority to construct and

299. *Calhoun LNG, LP & Point Comfort Pipeline Company, L.P.*, 120 F.E.R.C. ¶ 61,259 at P 3 (2007).

300. *Id.*

301. *Id*.

302. *Id.* at P 24.

303. *Id.* at P 30.

304. *Id.* at P 33.

305. *Id.* at P 65.

306. *Id.* at P 75.

307. *Id.* at P 90.

308. *Id.* at P 95.

309. *Southern LNG, Inc., Elba Express Co., LLC & Southern Natural Gas Co.*, 120 F.E.R.C. ¶ 61,258 (2007) [hereinafter *September 20 Order*].

operate a new interstate natural gas pipeline in Georgia and South Carolina to transport new volumes of LNG from Southern LNG, Inc.'s (Southern LNG) LNG terminal at Elba Island to interconnections with the Transcontinental Gas Pipe Line Corporation (Transco).[310] The April 4, 2007, order issued conditional approval of the Elba Express and Southern proposals pending completion of the FERC's environmental review.[311] The September twentieth order reflected the FERC's completed analysis of Southern LNG, Southern, and Elba Express' proposals, and granted the requested authorizations, subject to condition.[312]

Under NGA section three, FERC authorized Southern LNG to undertake a two-stage construction project to increase the storage capacity of the Elba Island LNG import terminal by 8.44 Bcf and increase its vaporization capacity by 900 MMcf per day. In Phase A of the project, Southern would build a new 200,000 cubic meter tank, with a storage capacity of 4.22 Bcf of LNG with a boil-off recondenser and three boil-off gas compressors; install submerged combustion vaporizers with a firm send-out capacity of 405 MMcf per day; and upgrade the current unloading docks to accommodate larger LNG ships and facilitate the simultaneous unloading of two LNG ships.[313] In Phase B of the project, Southern proposes to build an additional 200,000 cubic meter tank with a storage capacity of 4.22 Bcf of gas per day and install submerged combustion vaporizers with a firm send-out capacity of 495 MMcf per day.[314] The FERC considered that the Elba LNG terminal expansion would be a source of additional supplies of natural gas, and the project should provide benefits without adverse impacts on adjoining landowners, existing pipelines, or the environment.[315] The FERC also found that the environmental conditions set forth in the order will ensure that the adverse environmental impacts are limited. As such, the Southern LNG expansion project was deemed not inconsistent with the public interest.[316]

Southern also sought and received permission from the FERC under section seven of the NGA to transfer an undivided ownership interest (up to a volume equal to 1,175 MMcf per day) to Elba Express, at net book value in the Twin 30s Pipeline facilities.[317] It also received section seven authorization to acquire an undivided ownership interest in Elba Express' proposed pipeline between Port Wentworth and Rincon, Georgia – up to a volume of 500 MMcf per day – if Southern decides to proceed with the third stage of its previously-authorized Cypress Expansion Project.[318]

Elba Express, a Southern subsidiary, was granted permission under NGA section seven to construct and operate a forty-two and thirty-six inch diameter pipeline with a length of 189 miles. The pipeline will stretch from Port Wentworth to interconnections with Transco in Georgia and South Carolina.

310. *Id.*
311. *Id.*.
312. *Id*. at P 2.
313. *Id*. at P 4
314. *Id.* at PP 4-5.
315. *Id.* at P 53.
316. *Id.*
317. *Id.*
318. *Id* at PP 7-8.

Elba Express also received permission to operate a 10,000 horsepower compressor station in Jenkins County, Georgia to provide an additional 230 MMcf per day to the Transco interconnections.[319]

The EIS determined that construction and operation of the project is unlikely to result in significant adverse environmental impact.[320] The EIS further concluded that the project would be an environmentally acceptable action if it is constructed and operated in accordance with applicable laws and regulations, follows the proposed mitigation imposed on Southern LNG and Elba Express, and follows the additional recommended mitigation measures.[321] Among the environmental mitigation measures imposed on either Elba Express or Southern LNG were the following: to undertake efforts and investigations designed to protect water and wetland resources and vegetation and wildlife, to provide a site-specific plan of the construction technique(s) to be used, to implement a pipeline integrity management plan after construction in order to ensure public safety during its operation; and to develop an emergency response plan in consultation with the Coast Guard and state and local agencies.[322]

Despite the contentions of individual commenters opposing the project,[323] the FERC found no reasonable alternatives to a portion of the proposed Elba Express pipeline route, as this route was deemed environmentally preferable to the alternatives.[324] Other objections from local commenters regarding the pipeline route, capacity of the Transco system, balance of interests between the pipeline companies and landowners, adequate examination of the No Action Alternative, and the effects of global climate change were also examined and dismissed by the FERC.[325]

d. Cameron LNG, LLC

Cameron LNG (Cameron) first received authorization to site, construct, and operate an LNG terminal and an appurtenant pipeline near Hackberry, Louisiana in 2003, pursuant to NGA section 3(a).[326] In January 2007, the FERC authorized Cameron to expand the capacity of its LNG terminal facilities to increase the authorized send-out rate from 1.5 Bcf of natural gas per day to an ultimate send out rate of 2.65 Bcf per day, and to increase the send-out rate of the LNG terminal on an interim basis to 1.8 Bcf of natural gas per day, while the expansion project facilities were under construction.[327]

In February 2007, Cameron filed a request to modify the prior section three authorization, to permit it to increase the authorized send-out rate to 1.8 Bcf of natural gas per day before, rather than during, the construction of the expansion

319. *Id* at PP 9-11.
320. *Id.* at P 98.
321. *Id.* at P 99.
322. *Id* at PP 100-119.
323. *Id* at PP 128-30.
324. *Id* at P 137.
325. *Id* at PP 138-59.
326. *Cameron LNG, LLC,* 104 F.E.R.C. ¶ 61,269 (2003).
327. *Cameron LNG, LLC,* 118 F.E.R.C. ¶ 61,019 (2007).

facilities.[328] Cameron explained that it erred in qualifying its initial request to increase the send-out rate to up to 1.8 Bcf of natural gas per day with the phrase "while the Expansion Project facilities are under construction."[329] Cameron requested this modification so that customers can benefit from the initial vaporization capabilities of the LNG terminal as soon as practicable.[330]

On July 10, 2007, the FERC approved Cameron's request as consistent with the public interest, and stated that it will amend Cameron LNG's NGA section three authorization, subject to condition, to permit the increase in send-out capacity to occur prior to the commencement of construction of the expansion facilities.[331] There was no opposition to the request. The FERC found that the only impact that would result from an increase in the send-out rate, before the construction of any expansion facilities, would be an increase in LNG vessel traffic in the Calcasieu Ship Channel, which it felt would create no adverse effects on existing and future shipping; the request would not require any ground-disturbing activities or any construction-related environmental impacts.[332] The FERC imposed several environmental and non-construction-related conditions on Cameron before the commissioning of any LNG terminal facilities; these conditions were set forth in the January 2007, order.[333] These conditions concerned whale protection measures, the performance of a waterway suitability assessment, development of emergency response and cost sharing plans, and coordination with the Coast Guard regarding security measures.[334]

e. Trunkline LNG Company, LLC

On February 1, 2008, Trunkline LNG Company, LLC (Trunkline) filed an application under section 3(a) of the NGA requesting permission to install and operate a new 1,500 horsepower electric motor-driven pipeline compressor unit and related facilities at its existing LNG import terminal in Calcasieu Parish, Louisiana. Trunkline requested to use the compressor unit and related facilities to compress boil-off gas into the sendout pipeline when the terminal is not sending out natural gas from the LNG vaporization process.[335] Trunkline contended in its application that there would be no change to the existing certificated sustainable and peak sendout rates and that the construction and operation of the proposed facilities would not have a material impact on its cost of operations or revenues.

On May 15, 2008, the FERC granted approval of Trunkline's request. No interventions or protests to the application were filed. The FERC found that the request was not inconsistent with the public interest as the proposed facilities will enable Trunkline to safely and reliably send out additional boil-off gas

328. *Cameron LNG, LLC* 120 F.E.R.C. ¶ 61,028 at PP 2, 6 (2007).

329. *Id.* at 61,135.

330. *Id*. at P 6.

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

332. *Id.* at P 10.

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

334. *Id.* at P 14.

335. *Trunkline LNG, LLC, Co.* 123 F.E.R.C. ¶ 61,152 at P 5 (2008).

produced as a result of the recent expansion project.[336] The FERC approved the proposed compression facilities subject to several environmental conditions.[337]

2. Projects Requesting FERC Authorization

a. Florida Gas Transmission Company, LLC

On March 7, 2008, Florida Gas Transmission Company, LLC (FGT) submitted for filing a Prior Notice Request for Authorization under its Blanket Certificate to construct, own and operate an LNG Interconnect with Kinder Morgan Louisiana Pipeline, LLC (KMLP) located in Acadia Parish, Louisiana to receive re-vaporized LNG. On November 13, 2007, FGT filed a similar Prior Notice Application to interconnect to the proposed KLMP. Since that time, the location site for the proposed Kinder Morgan Meter Station (KMLP M/S) has been relocated to the eastern boundary of FGT's Compressor Station No. seven (C/S seven). On February 20, 2008, FGT filed a project modification request to relocate the proposed tie-in for the KMLP M/S from inside of C/S seven to the inside of the meter station. The determination was made that Prior Notice Regulations did not allow for such a modification and a new Prior Notice needed to be filed for this new location. FGT also concurrently filed a Notification to Vacate Blanket Certificate Authorization for this project issued in Docket No. CP08-24-000.[338]

On June 18, 2008, FGT submitted for filing a Prior Notice Request for Authorization under its Blanket Certificate originally issued in Docket No. CP82-553 to construct, own and operate an LNG Interconnect with Golden Pass Pipeline, LP (GPPL Interconnect) located in Orange County, Texas to receive re-vaporized LNG. FGT's pipeline system was authorized initially in Docket Nos. G-9262.[339] FGT is proposing to construct, own and operate the GPPL Interconnect on its twenty-four inch mainline to receive re-vaporized LNG from GPPL that is proposed to directly connect with the Golden Pass LNG Terminal, located near Sabine Pass, Texas.[340] The facilities will be constructed where FGT's existing twenty-four inch pipeline crosses FM 1135, downstream from Compressor Station No. six, near Mile Post 383.5 in Orange County, Texas. The proposed facilities to be constructed, owned, maintained and operated by FGT will include the installation of a twelve inch tap valve, on FGT's existing twenty-four inch pipeline within the limits of the environmentally cleared area for the proposed GPPL Meter Station and within the limits of FGT's maintained right-of-way, approximately forty feet of sixteen inch connecting pipe, electronic flow measurement equipment, gas chromatograph, and a prefabricated instrument and electrical building.[341]

336. *Id.* at P 9.

337. *Id.* at P 13.

338. Notice of Request Under Blanket Authorization, *Florida Gas Transmission Co., LLC*, 72 Fed. Reg. 68,135 (2007).

339. *Florida Gas Transmission Co.*, 11 F.E.R.C. ¶ 62,033 (1980).

340. *Florida Gas Transmission Co., LLC*, 73 Fed. Reg. 38,193 (2008).

341. *Id.*

3. Projects at Pre-Filing Stage

a. UGI Energy Services, LLC

On September 20, 2007, UGI Energy Services (UGI) initiated the FERC's National Environmental Policy Act (NEPA) pre-filing review to expand its proposed Temple LNG Storage Project located in Reading, Pennsylvania. The proposed Temple LNG Storage Project involves the construction and operation of a peaking plant on a three-acre parcel adjacent to UGI's existing Leesport Avenue LNG and Liquefaction Plant in Reading.[342] The project will interconnect with an existing natural gas transmission line owned by Texas Eastern Transmission, LP and the UGI Utility, Inc. distribution system. This peaking plant will provide UGI with one billion cubic feet (Bcf) of LNG storage capacity and approximately 150,000 dekatherms per day of additional vaporization capacity.

b. Oregon LNG Terminal and Oregon Pipeline Project

On May 31, 2007, LNG Development Company, LLC (d/b/a Oregon LNG) and Oregon Pipeline Company (collectively, "Oregon LNG") initiated the FERC's NEPA pre-filing review for its project located on the East Skipanon Peninsula near the confluence of the Skipanon and Columbia Rivers in Warrenton, Clatsop County, Oregon.[343] The proposed Oregon LNG terminal would be located on a ninety-six acre parcel of land that is owned by Oregon and leased to the Port of Astoria by the Oregon Department of State Lands.[344] The project will be designed with a natural gas sendout capacity of 1.0 billion Bcf/d and a peak of up to 1.5 Bcf/d.[345] The project will receive LNG discharged from oceangoing LNG carriers which will be stored in three 160,000 cubic meter aboveground, full containment LNG storage tanks. LNG will be vaporized into natural gas, and sent out from the terminal via an approximately 117-mile sendout Pipeline. The Oregon LNG project is still in the pre-filing stage with the FERC Staff recently conducting scoping meetings.

D. Alaska Pipeline Developments

Since July 2007, the FERC has submitted two reports to Congress concerning the progress made in licensing and constructing the Alaska natural gas pipeline pursuant to the requirements of section 1810 of the EPACT 2005.[346]

342. TEMPLE LNG STORAGE PROJECT, UGI ENERGY SERVICES INC., PROPOSED LNG EXPANSION PROJECT, ONTELAUNEE TOWNSHIP, PA., http://www.ugilng.com/expansion/ExpansionDetail/Files/Temple-LNG-Expansion-Project-Overview.doc (Last visited September 21, 2008).

343. Notice of Intent, *LNG Development Co., LLC and Oregon Pipeline Co*, 72 Fed. Reg. 50,356 (2007).

344. *Id.* at P 50,357.

345. *Id.*

346. F.E.R.C., *Third Report to Congress on Progress Made in Licensing and Construcing the Alaska Natural Gas Pipeline*, (Jan. 31, 2007).

1. Fourth Report to Congress on Progress Made in Licensing and Constructing the Alaska Natural Gas Pipeline

On August 15, 2007, the FERC submitted its Fourth Report to Congress, which described the key events that transpired since the FERC's Third Report submitted on January 31, 2007.[347] The primary development was the State of Alaska's May 2007, enactment and subsequent implementation of the Alaska Gasline Inducement Act (AGIA) program.[348] The AGIA is the state's vehicle for encouraging a project sponsor to proceed with the construction of the Alaska natural gas pipeline within a transparent and public process.[349] Under AGIA, Alaska's commissioner of Natural Resources and commissioner of Revenue will review applications from qualified project sponsors seeking an exclusive and enforceable license under the AGIA that entitles the licensee to state matching contributions of up to 500 million dollars for expenditures toward the planning and construction of an Alaskan natural gas pipeline project and other state administrative benefits.[350] All potential AGIA licensees must agree to certain specific requirements, terms and conditions regarding the construction and operation of the proposed project.[351] The AGIA license will be awarded on a competitive basis to the project sponsor that proposes a gas pipeline project that will sufficiently maximize the benefits to the people of Alaska in accordance with the criteria set forth in AGIA. The sponsors of an Alaskan project need not participate in the AGIA process as a prerequisite to filing an application with the FERC, and there is no certainty that the FERC would impose on a certificate holder the rate and other requirements included in AGIA after an independent determination on those matters.[352]

On July 2, 2007, (as amended August 6, 2007), Alaska released its Request for Applications (RFA) which provided the purpose, instructions, requirements, evaluative criteria, and other information to help interested parties submit an application for the competitive AGIA license selection process.[353] The deadline for filing an AGIA license application was set for November 30, 2007. The "Governor [announced] the state administration's goal... to submit its preferred project sponsor choice for an AGIA license in time for the next legislative session in January 2008, [and,] assuming legislative approval, the State would issue an AGIA license by the summer of 2008."[354]

The Fourth Report also provides that a July 27, 2007, ruling of the United States Court of Appeals for the D.C. Circuit affirmed in all respects the FERC orders promulgating regulations governing the conduct of open seasons for

347. *Id.*

348. *Fourth Report to Congress*, F.E.R.C., Aug. 2007, at 1.

349. *Id.* at 11.

350. *Id.*

351. *Id.* (Sponsors are required to make, among other things, a commitment to hold an open season by a certain date, a commitment to include at least five in-state delivery points for Alaska communities, and a commitment to seek a FERC certificate of public convenience and necessity by a certain date, as well as additional commitments to study the need for an expansion every two years after the gas line goes into service, and a commitment to roll-in rates for low-cost expansions.)

352. *Id.* at 3.

353. *Id.* at 12.

354. *Id.* at 2.

Alaska natural gas transportation projects, including procedures for the allocation of capacity.[355] The North Slope Producer Group had challenged certain specific aspects of the FERC's regulations adopted at 18 C.F.R. sections 157.36 and 157.37.

> [T]he Court found that the [FERC's] open season regulations fairly balance the... Alaska Natural Gas Pipeline Act's (ANGPA)... dual objectives of: (1) facilitating the timely development of an Alaska natural gas transportation project, and (2) encouraging the exploration for new gas reserves by assuring competitive access to the pipeline, [and] the Court upheld... the challenged regulations allowing the FERC... to require project design changes.[356]

The Fourth Report also documented recent developments concerning the Federal Coordinator, who is responsible for coordinating the expeditious actions of all federal agencies regarding the Alaska natural gas transportation project and ensuring the compliance of federal agencies with the provisions and deadlines of the ANGPA.[357]

> On May 22, 2007, the Federal Coordinator appeared before the Senate Energy and Natural Resources Committee['s] Subcommittee on Energy regarding S.1089, [the] bill to amend the [ANGPA] to provide more flexible personnel practices and cost reimbursement authority for most... Office of the Federal Coordinator (OFC)... operations.[358]

The Federal Coordinator also conducted numerous stakeholder meetings for the Alaska natural gas transportation project in both Alaska and Canada since the issuance of the Third Report. The Fourth Report also documented that the FERC Staff conducted a site visit to the pipeline project areas in July 2007, and continued its discussion with the Department of the Interior's Bureau of Land Management (BLM) and the Alaska Department of Natural Resources concerning the eventual EIS and project permitting.[359]

2. Fifth Report to Congress on Progress Made in Licensing and Constructing the Alaska Natural Gas Pipeline

On February 19, 2008, the FERC submitted its Fifth Report to Congress, which provided an update on key developments since the issuance of the Fourth Report.[360] The FERC documented that the "State of Alaska has moved forward with the process of selecting a preferred applicant under its... AGIA program."[361] Five applications were filed in response to Alaska's RFA by the November 30, 2007, deadline:[362]

355. *Id.* at 7.
356. *Id.* at 8.
357. *Id.* at 5.
358. *Id.* at 6.
359. *Id.* at 8.
360. *Id.*
361. *Id.* at 1.
362. FIFTH REPORT TO CONGRESS ON PROGRESS MADE IN LICENSING AND CONSTRUCTING THE ALASKA NATURAL GAS PIPELINE, FEDERAL ENERGY REGULATORY Commission 2-3 (2007). http://www.ferc.gov/legal/staff-reports/angta-fifth.pdf.

TransCanada Alaska Co., and Foothills Pipe Lines, Ltd. (jointly "TransCanada") "submitted an... application for a pipeline to run from the Alaska North Slope to connect with its Alberta hub;"[363]

"The Little Susitna Construction Company, a local Alaskan firm, submitted an... application with a... Chinese energy conglomerate, China Petroleum and Chemical Corporation, [for a proposed project that included] a pipeline to Valdez, where the gas would be liquefied for shipment [to China];"[364]

> The Alaska Natural Gasline Development Authority, a public corporation created by the citizens of Alaska, proposed to build a lateral "spur line" [] off a major pipeline project, which it assumed would be built by another entity."
>
> "The Alaska Gasline Port Authority, a municipal entity,... proposed a natural gas pipeline project from Prudhoe Bay to Valdez, where gas would be liquefied and exported [to Pacific Rim countries; and]
>
> AEnergia LLC, a start-up company... proposed to be the project manager for a natural gas pipeline project which would go from the North Slope to Alberta and would be jointly owned [by the natural gas producers (74 percent), the State of Alaska (25 percent), and AEnergia LLC (1 percent)].
>
> In addition to the [] five AGIA proposals, [ConocoPhillips Company (Conoco)] submitted a proposal outside of the AGIA process for a North Slope gas treatment plant and a pipeline to run from Alaska's North Slope to Alberta, and possibly on to Chicago....[365]

After review of the applications, on January 4, 2008, the State announced that it's determination that only TransCanada's proposal met the requirements of AGIA and would be considered as a conforming bid for an AGIA license.[366] "The State also rejected Conoco's proposal as not conforming to AGIA."[367] A sixty day public comment period, as required under AGIA, commenced on January 5, 2008, and ended on March 6, 2008. During this comment period, the State conducted a series of town hall meetings about the AGIA and TransCanada's proposal. The public was invited to provide comments on the TransCanada application. If the TransCanada proposal was found to satisfy the goal's of AGIA, the Governor of Alaska would submit such proposal to the State legislature for confirmation that an AGIA license should be granted to TransCanada. The State legislature is also independently conducting hearings in order to examine all of the proposals submitted under AGIA. As of the issuance of the Fifth Report, the State of Alaska anticipated taking legislative action to approve the AGIA license and issuance such license in June 2008.[368]

In December 2007, Congress passed the Energy Independence and Security Act of 2007 (P.L. 110-140),[369] "which included technical amendments to the ANGPA. The amendments allow the OFC flexibility in its hiring practices by granting a Title V exemption for competitive service employees and provide the

363. *Id.* at 3.

364. *Id.*

365. *Id.* at 5.

366. *Id.*

367. *Id.*

368. *Id.* (On May 22, 2008, Governor Palin recommended to the legislature that TransCanada receive the AGIA license. The legislature will have sixty days to review the findings of the FERCers and conduct its review before taking a final up or down vote on issuance of the license.)

369. *Id.*

OFC cost reimbursement authority."[370] "This authority is identical to that provided by the Federal Land Policy and Management Act (Section 304),[371] which allows the [BLM] to charge for reviews of permits and plans under oil and gas leases."[372] Moreover, the Fifth Report provided that the Federal Coordinator meets monthly with a federal interagency team representing all agencies with a role in permitting a natural gas project. "The Federal Coordinator also meets regularly with the State of Alaska pipeline team and Canadian federal and provincial officials."[373] By August 2008, the OFC expects at least one potential application to engage federal agencies as part of the pre-filing stakeholder process.

"Since the [issuance of the] Fourth Report, the FERC staff [has] visited the pipeline project area in Alaska and continued discussion with... [the] BLM concerning the eventual EIS and project permitting."[374] On January 29, 2008 "the FERC staff [also] held a technical conference [concerning its] third-party contracting requirements and resource expectations... [for] preparing an EIS on an Alaskan natural gas transportation project."[375] The FERC Staff invited contractor services to assist the FERC's environmental staff with the review of applications for an Alaskan natural gas pipeline and the design and preparation of an EIS for the anticipated project.

> The "FERC Staff presented an overview of its third-party contracting program... [and] described how an Alaskan natural gas pipeline EIS might be different than other pipeline EIS[s] because of the unique nature of the project, the unusual public and governmental participation and interest, and the expectation and requirements for conducting the [FERC's] environmental review within a particular timeframe.... FERC Staff responded to several questions about what the [FERC's] environmental review might include and described its intention to closely coordinate with other participating agencies."[376]
>
> The Fifth Report also notes that the United States Department of Energy's "Office of Fossil Energy issued [a report on January 29, 2008], entitled Alaska North Slope Oil and Gas: A Promising Future or an Area in Decline?,[377] [which] examines the potential for Arctic Alaska to remain a major contributor to the Nation's domestic energy supply under different development scenarios. The report also evaluates potential oil and natural gas resources on... Arctic Alaska, including the North Slope, regardless of whether certain areas are currently available for exploration and development.[378]

3. Findings of the Commissioners of Natural Resources and Revenue with Regard to the Producer Project

On May 22, 2008, the commissioners of the Natural Resources and Revenue for the State of Alaska (commissioners) issued written findings and

370. *Id.* at 7.
371. *Id.*
372. *Id.* at 8.
373. *Id.* at 6.
374. *Id.* at 7.
375. *Id.*
376. *Id.* at 8.
377. *Id.* at 6.
378. *Id.*

determination concerning whether to issue a license under the AGIA.[379] The commissioners recommended the issuance of a license to TransCanada Alaska Company, LLC and Foothills Pipe Lines LTD. Concerning the Denali Project, the commissioners found that the project sponsors did not provide certain commitments required by the AGIA. "The commissioners recognized that the [Denali Project] may be pursued to completion outside the AGIA process and without state fiscal concessions."[380] The commissioners noted that if the Denali Project proceeds to an open season, TransCanada would compete with the producer project for commitments.[381]

The May twenty-second report found that certain commercial terms of the Denali Project were undefined and that the project sponsors made no "commitment to adhere to their stated timeline or to achieve additional milestones, such as applying for a FERC certificate."[382] Other AGIA-related commitments discussed in the May twenty-second report concern: capital structure, expansion of facilities, and rolled-in rates.[383] Concerning timelines, the AGIA required an applicant to make enforceable commitments to advance a project. The Denali Project sponsors planned to hold an open season by 2010. The commissioners found that there was nothing to bind the Denali Project sponsors to any concrete action as a result of any open season they would conduct.[384] With regard to capital structure, section 130(10) of the AGIA requires that a potential licensee commit to use a capital structure with at least seventy percent debt and no more than thirty percent equity to determine the project's rates.[385] The commissioners found that the Denali Project sponsors did not commit to such a capital structure for ratemaking purposes.[386]

AGIA requires binding commitments by the licensee that it will pursue expansions by conducting non-binding open seasons at least every two years after the license is issued.[387] The May twnety-second findings state that the sponsors of the Denali Project have made no such commitment to expansion policies.[388] The AGIA also requires that a licensed project utilize rolled-in rate treatment for the costs of expansions provided that such treatment does not raise the rates to incumbent shippers by more that fifteen percent above the project's

379. TOM IRWIN & PAT GALVIN, WRITTEN FINDINGS AND DETERMINATION BY THE COMMISSIONERS OF NATURAL RESOURCES AND REVENUE FOR ISSUANCE OF A LICENSE UNDER THE ALASKA GASLINE INDUCEMENT ACT (AGIA), ALASKA DEPARTMENT OF NATURAL RESOURCES (2008).

380. *Id.* at 4.

381. *Id.*

382. *Id.* at 15.

383. *Id.*

384. SIXTH REPORT TO CONGRESS ON PROGRESS MADE IN LICENSING AND CONSTRUCTING THE ALASKA NATURAL GAS PIPELINE, FEDERAL ENERGY REGULATORY COMMISSION 3 (2008). http://www.ferc.gov/legal/staff-reports/angta-sixth.pdf.

385. *Id.* at 8.

386. *Id.*

387. *Id.*

388. *Id.*

initial rates.[389] The commissioners found that the Denali Project sponsors have not made any commitment regarding the pricing of expansion capacity.[390]

4. Pre-Filing Application of Denali – The Gas Pipeline Project

Recently, on June 16, 2008, ConocoPhillips and BP filed a request to use the NEPA pre-filing process for the Denali Project stating that the size of the project necessitated initiating pre-filing as soon as possible.[391] The Denali Project as proposed would be comprised of a four bcf/day pipeline carrying gas from the North Slope to delivery in Canadian markets and markets in the lower forty-eight states.[392] The application states that the request to use the pre-filing process much earlier than is normally the case with major pipeline projects.[393] Because of the scope of the Denali Project, the sponsors state that project design and application development will require a much longer time period (approximately thirty-six months) than is typically the case.[394] The sponsors project filing a certificate application with the FERC by August 2011. The sponsors desire FERC approval of that certificate application not later than August 2013. On June 25, 2008, the Office of Energy Projects approved the pre-filing request and waived the filing requirements and timeline stipulations of 18 C.F.R. 157.21 (d) and (f).[395]

The plans for the Denali Project include: (1) transmission pipelines to transport gas from where it is produced to connections with other portions of the Denali system, (2) a stand-alone gas treatment plant on the Alaska North Slope where gas will be processed to remove impurities and the residue gas chilled, and (3) a 48 to 52 inch pipeline capable of transporting 4.0 Bcf/day of gas.[396] The pipeline will generally follow the Dalton Highway south from the Alaska North Slope to Fairbanks where it will follow the Alaska Highway south to the Canadian border.

At the Canadian border, the Denali Project pipeline will connect to a pipeline to be constructed by Canadian affiliates in Canada that would transport natural gas from the Canadian border into Alberta. The pre-filing application notes that if additional capacity is needed to accommodate the delivery of the gas into the United States, Canadian affiliates may also construct a pipeline from Alberta southeast to the United States border, in which case the project would include a pipeline from the United States border across parts of North Dakota, Minnesota, Iowa, and Illinois to the Chicago area.[397]

The sponsors will engage in preliminary field studies along portions of the anticipated pipeline corridor during the summer of 2008. The sponsors have contacted landowners and agencies along that portion of the pipeline corridor

389. *Id.*
390. *Id.*
391. *Id.* at 2.
392. *Id.* at 3.
393. *Id.*
394. *Id.*
395. *Id.* at 2, 8, 10.
396. *Id.* at 3.
397. *Id.*

where they intend to conduct preliminary field studies. The pre-filing application states that ConocoPhillips began contacting landowners along the portion of the preliminary route not co-located with the Trans Alaska Pipeline System on behalf of the Denali project in April 2008.[398] The sponsors state that they are developing a Public Participation Plan, as required by the pre-filing process. The Public Participation Plan will identify the specific tools and actions to be used to facilitate stakeholder communication and public information. As of the time of filing of the pre-filing application request, the sponsors had established a project website, but had not yet established a single point of contact for the Denali Project.[399]

V. JURISDICTION

A. Offshore Gathering

On November 15, 2007, the FERC issued its Order on Remand[400] in consolidated dockets, in response to separate remands by the United States Courts of Appeals for the Fifth[401] and D.C.[402] Circuits, of separate proceedings involving the jurisdictional status of offshore pipelines owned by Jupiter Energy Corporation (Jupiter)[403] and Transco,[404] respectively. The FERC found that Jupiter's upstream facilities perform a gathering function, and Transco's downstream facilities perform a transmission function.

The FERC began with a restatement of its current policy that to determine which facilities are non-jurisdictional gathering, and which are jurisdictional transmission, it applies a "sliding scale" to the physical attributes of the facility in question.[405] The starting point is to consider the physical characteristics of the

398. Id.

399. BP and Conoco Phillips, *Denali – The Alaska Gas Pipeline*, http://www.denali-thealaskagaspipeline.com (last visited September 21, 2008).

400. *Transcontinental Gas Pipe Line Corp.*, 121 F.E.R.C. ¶ 61,157 (2007).

401. Jupiter Energy Corp. v. F.E.R.C., 482 F.3d 293 (5th Cir. 2007).

402. Williams Gas Processing-Gulf Coast Co. v. F.E.R.C., 475 F.3d 319 (D.C. Cir. 2006).

403. *Jupiter Energy Corp*., 103 F.E.R.C. ¶ 61,184, *reh'g denied*, 105 F.E.R.C. ¶ 61,243 (2003), *reh'g denied*, 106 F.E.R.C. ¶ 61,170 (2004); Jupiter Energy Corp. v. F.E.R.C., 407 F.3d 346 (5th Cir. 2005) [hereinafter *Jupiter I*]. Jupiter had applied for FERC approval in 2002 to transfer the facilities to Jupiter's parent, Union Oil Company of California (Unocal), for use as part of Unocal's gathering system.

404. *Transcontinental Gas Pipe Line Corp*., 96 F.E.R.C. ¶ 61,246, *order on reh'g*, 97 F.E.R.C. ¶ 61,298 (2001), *aff'd*, Williams Gas Processing-Gulf Coast Co. v. F.E.R.C., 331 F.3d 1011 (D.C. Cir. 2003) [hereinafter *Transco I*]. Transco had applied for FERC approval in 2001 to "spin down" the facilities in question to its gathering affiliate Williams Gas Processing-Gulf Coast Company, LP (Williams).

405. 121 F.E.R.C. ¶ 61,157 at P 3. In determining whether the "primary function" of a natural gas facility is transmission or gathering, FERC looks at (1) length and diameter of the pipeline; (2) proximity to the central point in the field; (3) geographic configuration of the facility; (4) proximity to processing plants and compressors; (5) location of wells along all or part of the facilities; and (6) operating pressure. FERC does not deem any one factor as determinative. EP Operating Co. v. F.E.R.C., 876 F.2d 46, 48 (5th Cir. 1989).

FERC reformulated the primary function test with respect to offshore facilities by: (1) adopting an additional analytical element applicable to systems that contain a centralized aggregation point, (2) adjusting the weight to be afforded the "behind-the-plant" criterion so that the location of processing plants is not necessarily determinative and can be outweighed by other factors, and (3) focusing primarily on physical factors. *Sea Robin Pipeline Company*, 87 F.E.R.C. ¶ 61,384 (1999), *order denying reh'g*, 92 F.E.R.C. ¶ 61,072 (2000).

facility, but the FERC also gives "some weight" to non-physical factors, including the purpose, location, and operation of the facility, and the general business activities of the owner of the facility. But, these non-physical factors are secondary, and "only come into play if application of the physical factors results in a close call."[406]

1. The Jupiter Facilities

In evaluating the Jupiter facilities, the FERC noted that in the *Jupiter Energy Corpartion. v. F.E.R.C.*[407] court took issue with the FERC's failure to explain its reasons for dismissing non-physical factors that the court found relevant, including the facts that Jupiter's only remaining shipper is its parent, Unocal; neither Jupiter nor Unocal owns any other jurisdictional facilities; Unocal's business activity is gathering and production; and Unocal is seeking to integrate Jupiter's facilities into Unocal's own gathering system.[408] In the court's view, all of these other physical and non-physical factors weighed in favor of a gathering-function determination.[409]

On remand, and after further reflection, the FERC concluded that: (1) the lengths and diameters of the Jupiter pipelines are consistent with a gathering function; (2) the operating pressures (750 to 950 pounds per square inch gauge) are "not inconsistent with the operating pressures of other offshore systems found to be gathering;"[410] (3) the FERC had previously placed "too much significance" on Unocal's 39A Platform as a central aggregation point; (4) Jupiter's original system was not constructed under the FERC's jurisdiction, and its facilities were considered to be non-jurisdictional gathering facilities and operated as such for over fifteen years before the Federal Power FERC determined that they performed a transmission function;[411] and (5) that what remains of Jupiter's system today are two pipelines that, since 1992, have been used solely to transport gas produced by its parent Unocal to Transco's and Tennessee's systems.[412] All these factors, in the FERC's view, "support a finding that Jupiter's pipeline will perform a gathering function when integrated with Unocal's existing production and gathering system."[413]

2. The Transco Facilities

As to Transco's facilities, the FERC applied the primary function test to the entire thirty-seven miles of twenty-four-inch pipeline, finding that: (1) the large diameter and length of the line is typical of a shallow-waters transmission

406. 121 F.E.R.C. ¶ 61,157 at P 11.

407. 482 F.3d 293 (5th Cir. 2007).

408. *Id.*

409. *Jupiter Energy Corp.*, 482 F.3d at 297-8.

410. 121 F.E.R.C. ¶ 61,157 at P 14 *citing Amerada Hess Corp.*, 52 F.E.R.C. ¶ 61,268 at p. 62,019-23 (1990); *Pacific Offshore Pipeline Co.*, 64 F.E.R.C. ¶ 61,167 at 62,508-09 (1993). The FERC hastened to point out that operating pressures are not dispositive of the determination of function.

411. 121 F.E.R.C. ¶ 61,157.

412. 121 F.E.R.C. ¶ 61,157 at n. 23. "In 1992, the [FERC] determined that it was unlikely that any other potential shippers would want capacity on Jupiter's system. Unocal acquired Jupiter in 1997 and has been unsuccessful in attracting other shippers to Jupiter's facilities." *Id.* (internal citations ommitted).

413. 121 F.E.R.C. ¶ 61,157 at 18.

facility;[414] (2) the increase in diameter at the Vermilion 22 Platform (from a twelve inch line to Transco's twenty-four inch line) marks a central point of aggregation where gathering ends and transmission begins;[415] (3) the geographic configuration of the line and the location of wells support a finding of transmission; (4) the lack of compression on the line and the location of the Cow Island processing plant downstream are not dispositive of the line's function;[416] (5) while the 750 to 1,000 psig operating pressure of the twenty-four inch line is not inconsistent with that of other offshore systems found to be gathering,[417] including the Jupiter system addressed in the same Remand Order, that range of operating pressures is also not inconsistent with operating pressures of offshore transmission facilities;[418] and (6) Transco's facility traverses a greater distance than Jupiter's without receiving any additional gas. Noting that because the physical factors strongly weigh toward a determination that the Transco pipeline functions as a transmission facility, there is no "close call" that would warrant further inquiry to the non-physical factors, which happen also to indicate that all of Transco's thirty-seven mile line should be jurisdictional: (1) Transco's affiliate Williams, while a gathering company, does not own any of the production shipped through the twenty-four inch line; and (2) whereas Jupiter's facilities transport gas only owned by its parent, Unocal, numerous other third-party shippers transport through Transco's twenty-four inch line.[419]

In conclusion, under the primary function test, the FERC found that Transco's line performs a transmission function subject to the FERC's jurisdiction.[420]

B. Missouri Gas Company Reorganization

On April 20, 2007, the FERC issued an order that conditionally authorized Missouri Interstate Gas, LLC (Missouri Interstate) (an interstate pipeline), Missouri Gas Company, LLC (Missouri Gas), and Missouri Pipeline Company, LLC (Missouri Pipeline) (both Hinshaw pipelines exempt from FERC jurisdiction under Section 1(c) of the NGA)[421] (jointly, the Applicants) to reorganize themselves into one interstate natural gas company.[422]

"The [Missouri Public Service FERC] (MoPSC) requested the [FERC] to abstain from ruling on the merits of the applications for certificates of public

414. *Venice Gathering Co.*, 97 F.E.R.C. ¶ 61,045 at p. 61,250 (2001); *Dauphin Island Gathering System*, 79 F.E.R.C. ¶ 61,666 (1997).

415. *Trunkline Gas Co.*, 95 F.E.R.C. ¶ 61,337, *order on reh'g,* 97 F.E.R.C. ¶ 61,169 at p. 61,794 (2001).

416. 97 F.E.R.C. at 61,251.

417. *Northern Natural Gas Co.*, 93 F.E.R.C. ¶ 61,101 (2002); *Tarpon Transmission Co.*, 78 F.E.R.C. ¶ 61,278 (1997).

418. *Enron Gulf Gathering Limited Partnership*, 79 F.E.R.C. ¶ 61,039 at p. 61,178 (1997); *Sea Robin Pipeline Co.*, 71 F.E.R.C. ¶ 61,351 at p. 62,402 (1995).

419. 121 F.E.R.C. 61,157.

420. *Id.* at P 29.

421. 15 U.S.C. 717 (2005). (A "Hinshaw pipeline" is a company engaged in the transportation of natural gas in interstate commerce but exempt from FERC jurisdiction under 1(c) of the NGA by virtue of meeting the following conditions: (1) it receives the gas within or at the boundary of a state, (2) all gas so received is consumed within such state, and (3) the rates and services of such person are subject to regulation by the state.)

422. 119 F.E.R.C. ¶ 61,074 (2007).

convenience and necessity and requests for abandonment authorization submitted by Applicants pending resolution of the proceeding initiated by the MoPSC in the Circuit Court for Cole County, Missouri."[423] The MoPSC argued that it would be appropriate for the FERC to apply principles consistent with those articulated in *Younger v. Harris*[424] and abstain from acting on the applications. In the alternative, the MoPSC moved the FERC to reject or dismiss the application filed in this proceeding pursuant to Rule 2001(b)(1) of the FERC's regulations.[425] The MoPSC also contended that because the Applicants have not indicated that they have any intention of securing MoPSC approval to consolidate pursuant to Missouri Revised Statutes section 393.190.1,[426] their application "should be rejected for failure to '"comply with [this] applicable statute."''[427] The MoPSC characterized the application as flouting state law and urged the FERC not to condone this action by processing the application.[428]

The FERC declined to abstain from acting on the Applicants' proposal. The April twenty-seventh Order stated that the Supreme Court has made clear that the doctrine of abstention is "the exception, not the rule," and "an extraordinary and narrow exception""[429] at that. Here, as the MoPSC conceded, the FERC has exclusive jurisdiction over NGA issues. The FERC cited *Stowers Oil & Gas Co.*,[430] where federal law governs (in that case, also the NGA), the federal agency has exclusive jurisdiction, and the expertise, to administer the statutes entrusted to it.[431] Accordingly, in the handful of proceedings in which abstention requests have been filed, the FERC's practice has been to deny the requests even if there is a related pending state proceeding when, as here, the issues before the FERC are within its exclusive jurisdiction.[432]

The FERC also denied the MoPSC's alternative request that the FERC reject the applications as a matter of substantive law.[433] The FERC stated it is appropriate for an agency to reject a filing where it is plainly deficient on its face or "is so patently a nullity as a matter of substantive law, that administrative efficiency and justice are furthered by obviating any docket at the threshold rather than opening a futile docket."[434] By way of example, in interpreting this standard, the Supreme Court upheld the rejection of an application for a certificate of public convenience and necessity when the application was

423. *Id.* at P 16.

424. 401 U.S. 37 (1971).

425. 18 C.F.R. § 385.2001(b)(1).

426. 119 F.E.R.C. ¶ 61,074 (2007).

427. *Id.*

428. *Id.* at P 17.

429. Colorado Water Conservation District v. U.S., 424 U.S. 800, 813, (1976) *quoting* County of Allegheny v. Frank Mahshuda Co., 360 U.S. 185, 188-189 (1959); *See also Stowers Oil & Gas Co.*, 33 F.E.R.C. ¶ 61,207 at p. 61,423 (1985).

430. *Stowers Oil & Gas Co., et al.*, 44 F.E.R.C. ¶ 61,128 (1988).

431. 33 F.E.R.C. ¶ 61,207 at 61,423.

432. *Id*. *See also Florida Power & Light Co.*, 41 F.E.R.C. ¶61,153 at p. 61,382 (1987); *Central Power and Light Co.*, 8 F.E.R.C. ¶ 61,065.

433. 119 F.E.R.C. ¶ 61,074 at P 26.

434. Municipal Light Boards v. FPC, 450 F.2d 1341, 1346 (D.C.Cir. 1971).

supported by a contract containing a clause that would have resulted in summary rejection under the FERC's regulations.[435]

In accordance with the "patently a nullity" standard articulated in *Municipal Light Boards v. FPC*,[436] the FERC has refused to reject filings that were not found to be "patently deficient or a violation of an applicable statute, regulation, or [FERC] policy."[437] The FERC disagreed that Missouri Revised Statute section 393.190.1 or the conditions in the Missouri Pipeline and Missouri Gas state certificates are "applicable" statutes, rules or orders within the meaning of Rule 2001. The FERC found the filing was in accordance with the NGA and the FERC's relevant regulations and policies. The FERC found MoPSC had not pointed to an applicable Federal statute or FERC regulation that the Applicants violated by exercising their rights under section seven of the NGA to make the filing.[438] While the FERC's ultimate decision on the merits of an application under the NGA may include a consideration of the potential implications, if any, of state or local laws or regulations to which applicants may be subject, the FERC did not view failure to demonstrate compliance with such laws and regulations as grounds for rejection of a filing under Rule 2001.[439] Accordingly, the FERC found no support for the notion that the application is a "patent nullity" for which rejection is appropriate.

The FERC stated that it understood the obligation that the states have in protecting the interests of natural gas consumers in their respective states. While the FERC takes a broader view of the public interest because it focuses on the national market, the FERC nevertheless considers the effects of any proposal on existing shippers as well as on other state interests, such as the environment.[440]

Parties also averred that there must be changed circumstances with respect to the Applicants' operations, lacking here, to warrant a change from state to federal jurisdiction. However, the FERC found the parties' arguments with respect to changed circumstances unclear as to what circumstances they believe must change before a state-regulated pipeline may apply to the FERC for authorization to operate in interstate commerce.[441]

The Applicants stated they plan to treat the three pipelines' existing service agreements as negotiated rate contracts. The FERC accepted the proposed tariff language concerning negotiated rate provisions.[442] The order stated that, in certificate proceedings, the FERC establishes initial recourse rates but does not make determinations regarding specific negotiated rates for any proposed

435. Federal Power Comm'n v. Texaco, 377 U.S. 33 (1964).

436. Municipal Light Boards v. FPC , 450 F.2d at 1346.

437. *American Electric Power Service Corporation*, 97 F.E.R.C. ¶ 61,103 at p. 61,543 (2001); *See also Tennessee Gas Pipeline* Company, 69 F.E.R.C. ¶ 61,235 at p. 61,886 (1994); 18 C.F.R. § 385.2001 (Rule 2001) (2007) (which authorizes rejection of any filing that does not "comply with any applicable statute, rule, or order.")

438. 119 F.E.R.C. ¶ 61,074 at P 27.

439. *See, e.g., Carolina Gas Transmission Corp., SCG Pipeline, Inc. & South Carolina Pipeline Corp., 116 F.E.R.C. ¶ 61,049* (seeking information regarding the status of state authorizations related to the divestiture of facilities).

440. 119 F.E.R.C. ¶ 61,074 at P 28.

441. *Id.* at 30.

442. *Id.* at P 76.

service.[443] Rather, in order to comply with the Alternative Rate Policy Statement[444] and its decision in *NorAm Gas Transmission Company*,[445] the FERC directed that Missouri Gas file its negotiated rate contracts or numbered tariff sheets not less than sixty days, or more than ninety days, prior to the commencement of service.

The Applicants proposed that the service agreements that the Missouri Pipeline and Missouri Gas entered into with their existing customers while they were under MoPSC jurisdiction remain in effect after the merger and that these contracts be accepted as negotiated rate agreements and, where applicable, as non-conforming service agreements under the new Missouri Gas' Part 284 tariff.[446] The Applicants explained that because the existing contracts were executed under state regulation, their format is significantly different from the form of service agreement in their pro forma tariff, which is based on the FERC-approved service agreement in Missouri Interstate's current tariff.[447] Under the circumstances of this case, the Applicants believed that attempting to redline the differences between the nonconforming agreements and the pro forma service agreement would not be practicable and would result in an unreadable document.[448] Therefore, they requested waiver of this requirement.

The FERC found that because the Applicants are proposing to integrate their intrastate and interstate transmission systems and operate as one jurisdictional interstate pipeline, the new pipeline, Missouri Gas, should provide service to the Applicants' customers under the service agreement in its Part 284 tariff and not use its existing MoPSC-approved contracts as nonconforming service agreements.[449] The FERC recognized that in order to provide jurisdictional service to the existing shippers, the new Missouri Gas must renegotiate its existing contracts using its standard pro forma service agreement as the starting point for drafting any negotiated rate or contract consistent with FERC policies.[450] To the extent that the new Missouri Gas wishes to grandfather any provision in its existing contracts, Missouri must file the agreements reflecting the deviations from the standard pro forma service agreement in redline/strikeout format.[451]

Also regarding nonconforming contracts, the Applicants indicated that Missouri Pipeline and Missouri Gas currently have full requirements contracts

443. *CenterPoint Energy – Mississippi River Transmission Corp.*, 109 F.E.R.C. ¶ 61,007 at P 19 (2004); *ANR Pipeline Co.*, 108 F.E.R.C. ¶ 61,028 at P 21 (2004); *Gulfstream Natural Gas System, LLC*, 105 F.E.R.C. ¶ 61,052 at P 37 (2003); *Tennessee Gas Pipeline Co.*, 101 F.E.R.C. ¶ 61,360 at n. 19 (2002).

444. *Alternative to Traditional Cost-of-Service Ratemaking for Natural Gas Pipelines and Regulation of Negotiated Transportation Services of Natural Gas Pipelines*, 74 F.E.R.C. ¶ 61,076 (1996), *reh'g and clarification denied*, 75 F.E.R.C. ¶ 61,024 (1996*), reh'g denied;* 75 F.E.R.C. ¶ 61,066 (1996); *petition for review denied; Burlington Resources Oil & Gas Co. v. FERC*, 172 F.3d 918 (D.C. Cir. 1998).

445. 77 F.E.R.C. ¶ 61,011 (1996).

446. *Notice of Applications for Certificates of Public Convenience and Necessity and Abandonment Authorizations*, 71 Fed. Reg. 40,888 (2006).

447. *Id.*

448. *Id.*

449. *Id.*

450. *Natural Gas Pipeline Negotiated Rate Policies and Practices*, 104 F.E.R.C. ¶ 61,134 (2003).

451. *Id.* at n. 33.

with several small municipalities that they serve directly or indirectly. The FERC stated that the full requirements or load growth provision of these contracts is an impermissible term and condition of service because this type of service will not be offered to all of the new pipeline's customers. In a previous case where a nonconforming agreement included a similar growth option wherein the customer could increase its MDQ at specified times and by specified amounts,[452] the FERC held that the provision was a negotiated term and condition of service different from the services offered to other customers, which its policies do not permit.[453] The FERC stated that if Missouri Gas desired to provide a full requirement service as proposed here, it must mitigate the risk of undue discrimination among the new pipeline's customers by filing to place such a service into its tariff so that the service will be generally available to all customers.[454] If Missouri Gas will not provide such service, the full requirements/load growth provisions was required to be removed from the service agreements with its shippers.

On February 19, 2008, the FERC issued an order granting rehearing, in part, and denying rehearing, in part, as well as clarifying certain aspects of the April 20, 2007, Order (February ninteenth Order).[455] In addition, this order addresses the July 5, 2007, filing made in compliance with the April 20, 2007, Order and submitted by MoGas, the new name for the interstate pipeline that will be the result of the merger of the Applicants.

On rehearing, AmerenUE asserted new grounds for why the FERC should have rejected or dismissed the application and why it should reverse its earlier decision on rehearing. It contended that the FERC should have applied the doctrine of judicial estoppel and declined to review the application on its merits because the Applicants allegedly made statements in the MoPSC proceeding in which Gateway Pipeline Company (Gateway) acquired Missouri Gas and Missouri Pipeline and in the instant proceeding before the FERC that were inconsistent.[456]

"AmerenUE assert[ed] that Missouri Gas, Missouri Pipeline, and Gateway made commitments before the MoPSC not to flow gas out of Missouri over the border-crossing pipeline segment that was owned, but not operated, by Missouri Pipeline and to establish a separate interstate entity to own that segment if Gateway chose to operate it to flow gas into Missouri."[457] According to AmerenUE, the purpose of the judicial estoppel doctrine is "to [preserve] the integrity of the judicial process... by 'prohibiting parties from deliberately changing positions according to the exigencies of the moment'...."[458] It noted

452. *Northern Natural Gas Co.,* 111 F.E.R.C. ¶ 61,141 (2005).

453. *Id.* at P 4.

454. 122 F.E.R.C. ¶ 61,136 at P 30.

455. 122 F.E.R.C. ¶ 61,136.

456. *Missouri Interstate Gas, LLC, Missouri Gas Co., LLC, and Missouri Pipeline Co., L.L.C.*, 122 F.E.R.C. ¶ 61,136 at P 36 (2008).

457. *Id.* at P 28.

458. New Hampshire v. Maine, 532 U.S. 742 (2001) (internal citations ommitted).

that this equitable remedy applies in administrative proceedings as well as judicial ones.[459]

> AmerenUE point[ed] out that the United States Supreme Court in New Hampshire v. Maine[460] offered guidelines for when it is appropriate to apply the doctrine of judicial estoppel, including: (1) whether a party's position is clearly inconsistent with its earlier position, (2) whether the party succeeded in persuading a court to accept its earlier position such that a perception is created that either the first or second judicial forum has been misled, and (3) whether the party asserting the inconsistent position would either obtain an unfair advantage or impose an unfair detriment on the opposing party.[461]

AmerenUE maintains that all of these factors are present and that if the FERC does not reverse its decision to consider and approve the application on rehearing, it would be reversible error.

The Applicants pointed out that the doctrine of judicial estoppel was designed to protect the integrity of the courts, not the parties to a proceeding.[462] They asserted that AmerenUE and the other protestors did not suffer any unfair detriment as a result of the Applicants' seeking an NGA section 7(c) certificate, nor did the Applicants obtain an unfair advantage. Thus, in their view, to the extent AmerenUE contends that federal regulation of Missouri Gas and Missouri Pipeline would be detrimental to it and other customers, they are not in any worse position now than they would have been had no acquisition proceeding taken place before the MoPSC wherein the alleged inconsistent statements were made.

The FERC issued a rehearing order on February twenty-ninth finding that the factors cited by the Supreme Court with respect to judicial estoppel are not mandatory, but are intended to provide guidance.[463] The FERC stated that AmerenUE misconstrued the context in which previous statements were made by the Applicants, as well as the nature of the statements.[464] In the FERC's opinion, "all of the circumstances described by AmerenUE, as discussed below, are susceptible to a different and more plausible interpretation than that urged by AmerenUE."[465]

> "First, with regard to context, when the MoPSC issued the [original 1989] certificate to Missouri Pipeline, it apparently was concerned that the pipeline's ownership of an interconnected segment of pipeline that crossed the border between Missouri and Illinois would call into question the new pipeline's eligibility for exemption from federal regulation under section 1(c) of the NGA."[466] Therefore, according to AmerenUE, the MoPSC conditioned the certificate on Missouri Pipeline's obtaining a declaration of exemption from the [FERC] and on

459. Mulvaney Mechanical, Inc. v. Sheet Metal Workers International Ass'n, Local 38, 288 F.3d 491, 504 (2d Cir. 2002).

460. 122 F.E.R.C. ¶ 61,136 at P 30.

461. New Hampshire v. Maine, 532 U.S. 742 (2001).

462. 28 Am. Jur. 2d *Estoppel and Waiver* § 74 30.90 (2007); Data Gen. Corp. v. Johnson, 78 F.3d 1556, 1565 (Fed. Cir. 1996).

463. 122 F.E.R.C. ¶ 61,136 at P 30.

464. *Id.* at P 36.

465. *Id.* at P 37.

466. *Id.* at 38; *See*, 15 U.S.C. § 717 (2007).

> maintaining a physical separation between the facilities that would be subject to state jurisdiction and the border-crossing segment.[467]

The FERC responded that this concern was not unusual since, historically, Hinshaw pipelines were kept physically separate from downstream pipelines capable of transporting gas out of state to avoid even the possibility that gas transported by the Hinshaw pipeline could be consumed out of state contrary to the NGA section 1(c) exemption.[468] Given this context, the FERC stated it was evident that Missouri Gas' and Missouri Pipeline's agreement to the certificate condition requiring physical separation was not unusual and cannot be construed as a commitment never to seek to change its jurisdictional status.

In sum, the FERC stated that it did not believe that the Applicants were attempting to deceive the MoPSC or the parties to the state certificate proceedings when they agreed to the conditions placed on those certificates.[469] The FERC stated that,

> it is reasonable to assume that the agreement to continue operating Missouri Gas and Missouri Pipeline as Hinshaw pipelines reflected Gateway's business model for those pipelines at the time it acquired them.[470] However, business models change for a variety of reasons, including, among others, to obtain better tax or regulatory treatment, to expand the business into new markets, or to obtain economic efficiencies. The fact that such changes occur cannot reasonably be characterized as improper inconsistencies on the part of the business owners or managers. For these reasons, the [FERC stated that it] was not persuaded that the Applicants' positions in either the acquisition proceeding or in this proceeding lend themselves to the kind of inconsistencies the doctrine of judicial estoppel contemplates.[471]

VI. KANSAS AD VALOREM LITIGATION

On January 22, 2008, the United States Court of Appeals for the D.C. Circuit issued an opinion vacating the FERC orders requiring Burlington Resources Oil and Gas Company LP (Burlington Resources) to refund to two pipelines (Northern Natural Gas Company (Northern) and (Panhandle Eastern Pipe Line Company) amounts from gas sales that exceeded the maximum lawful price under the NGPA.[472]

On remand of *Burlington I*,[473] the the FERC reaffirmed its orders stating that the take-or-pay settlements were unenforceable because they allowed sellers to collect more for natural gas than the maximum lawful price in contravention of the NGPA; whereas, the Omnibus settlements were an exercise of

467. *Id.*

468. *Empire State Pipeline*, 56 F.E.R.C. ¶ 61,050, at p. 61,169 (1991), *reh'g granted in part, and denied in part*, 61 F.E.R.C. ¶ 61,091 (1992) ("[t]he FERC construes the Hinshaw exemption strictly to require separation of gas which will be consumed in a state, which is eligible for exemption under § 1(c), from gas moving in interstate commerce").

469. *Id.* at P 42.

470. *Id.*

471. *Id.* at P 43.

472. 513 F.3d 242 (D.C. Cir. 2008).

473. Burlington Resources Oil & Gas Co., LP v. FERC, 396 F.3d 405 (C.A.D.C. 2005).

prosecutorial discretion given the substantial benefits that flowed from the Omnibus settlements.[474]

In *Burlington Resources, Inc. v. FERC*,[475] the D.C. Circuit rejected the FERC's reasoning and vacated the orders that required Burlington to pay refunds. At the outset, the court concluded that the liability associated with Kansas' *ad valorem* issue reasonably fell within the indemnity language of the take-or-pay settlements.[476] The court then rejected the FERC's proffered distinction between the take-or-pay settlements and the Omnibus settlement – that it was exercising its prosecutorial discretion when it approved the Omnibus settlements.[477] According to the court, the FERC enjoys prosecutorial discretion only when it is acting as a prosecutor, which it was not doing in the case of the Omnibus settlements. The court held that the NGPA, while invalidating private agreements to pay more than the maximum lawful price, does not prohibit settlement agreements over past gas sales that allow a party to retain past payments that might later be construed to embody prices in excess of the statutory price ceilings.[478] The law does not prevent purchasers from later exchanging accrued rights (to gas sales at the maximum lawful price) for other valuable consideration especially during a period of uncertainty in the law.[479]

On remand, the FERC held that Burlington's take-or-pay settlements with the pipelines were fully enforceable and that Burlington was released from any obligation to make refunds to the pipelines associated with overpayments for Kansas ad valorem taxes.[480] The FERC ordered the two pipelines to return the amount of the refunds that Burlington had paid to them with interest.[481] The FERC stated that because the pipelines had already stated that amount of refunds they believe were due from Burlington and had flowed through the refunds that Burlington had paid them to their customers, there was no need for further proceedings.[482]

VII. STATE RATEMAKING ISSUES FOR GAS DISTRIBUTION UTILITIES

A. Introduction

Over the last few years, there has been an increased focus in the distribution segment of the natural gas industry to address the continuing business challenges faced by local distribution companies (LDCs) through innovative ratemaking and regulatory solutions. The major business challenges faced by LDCs operating in North America that are driving this focus include:

Weather variability [and warming temperatures];

474. *Burlington Resources Oil & Gas Co.*, 112 F.E.R.C. ¶ 61,053, *reh'g denied*, 113 F.E.R.C. ¶ 61,257 (2005).

475. Burlington Resources Oil & Gas Co., LP v. FERC, 513 F.3d 242 (C.A.D.C. 2008).

476. *Id.*

477. *Id.*

478. *Id.*

479. *Id.*

480. *Burlington Resources Oil & Gas Co.*,123 F.E.R.C. ¶ 61,151 (2008).

481. *Id.* at P 11.

482. *Id.* at P 12.

Declining use per customer;
Rising and volatile wholesale natural gas prices;
Increases and volatility in customers' bills as a result of gas price fluctuations;
Increased impact and promotion of energy efficiency and conservation measures;
Rising costs of labor and materials for expansion and growth;
Rising and uncontrollable bad debt expenses caused primarily by the level of wholesale natural gas prices; and
Increasing requirements applicable to maintenance and improvement of aging infrastructure and system reliability.[483]

These business challenges pertaining to weather, customer use, wholesale gas prices, bad debt expenses, energy efficiency and conservation, labor and materials costs, and infrastructure initiatives have had a combined effect of introducing elements of considerable, and recurring variability, unpredictability and uncontrollability related to an LDC's costs of delivery service and the gas usage factors used to set its base rates to recover such costs.[484]

B. A "Rethinking" of LDC Ratemaking Concepts

Some industry participants believe that these business conditions represent serious challenges to the financial integrity of an LDC and to the ability of its customers to manage their energy needs.[485] At the same time, there is a growing concern from some industry participants that the current rate design approaches may not be working as intended as evidenced by stakeholder impacts and original rate design objectives not being satisfied.

The above-described business challenges have led to changes in the ratemaking approaches traditionally relied upon by LDCs, and approved by utility regulators. LDCs are implementing various innovative ratemaking approaches that can be characterized in broad terms as follows:

1. Revenue decoupling mechanisms,
2. Rate design utilizing a single, fixed monthly charge.
3. Automatic adjustment rate mechanisms or rate trackers" (that address items such as the recovery of bad debt expenses, infrastructure replacement costs, energy efficiency program costs, and margin revenue losses due to warmer-than-normal weather).[486]
4. Revenue (return) stabilization mechanisms.[487]

483. AMERICAN GAS ASSOCIATION, STATE REGULATORY DIRECTIONS: UTILITY CHALLENGES AND SOLUTIONS, http://www.aga.org/NR/rdonlyres/8DD4AC5D-8DF1-403A-9234-BB6FCEB2CA38/0/FeingoldWorkshopFF08.ppt (last visited September 22, 2008).

484. *Id.*

485. Special Comment Report , Impact of Conservation on Gas Margins and Financial Stability in the Gas LDC Sector, Moody's Investor Service (June 2005); Integrated Natural Gas & Gas Utilities – How Bad Will Bad Debt Expense Be?, Citigroup Global Markets (October 20, 2005); Proposed General Increase in Natural Gas: North Shore Gas Co., Ill. Commerce Comm'n, Docket No. 07-0241 (2008); Proposed General Rate Increase in Natural Gas: Peoples Light and Coke Co., Ill. Commerce Comm'n, Docket No. 07-242 (2008); Mo. Gas Energy's Tariffs Increasing Rates for Gas Service Provided to Customers in the Company's Mo. Service Area, Mo. Pub. Serv. Comm'n, Case No. GR-2006-0422 (2007).; Public Utilities FERC of Ohio, Opinion and Order issued in Case No. 07-589-GA-AIR (2008).

486. American Gas Association, *supra* n. 487.

487. *Id.*

The continuing decline in use per customer and the resulting inability of gas distribution utilities to recover their approved level of margin revenues has been a continuing, challenge to the gas distribution utility segment of the energy industry.[488] And although this serious problem has been addressed, or at least partially mitigated, for a growing number of gas utilities in recent years through innovative ratemaking approaches, it continues to impact many utilities' financial performance.

The revenue shortfall problem for gas distribution utilities has received much attention from state regulators over the last five years. To effectively mitigate the variability in revenues caused primarily by weather and declining use per customer, regulators have implemented a number of ratemaking solutions, including:

1. Revenue decoupling mechanisms that adjust rates for changes in usage caused primarily by weather and energy conservation;
2. Straight-Fixed Variable ("SFV") rate structures;
3. Weather Normalization Adjustment ("WNA") mechanisms that adjust rates for changes in usage caused by weather;
4. Monthly customer charges that more fully reflect the gas utility's fixed costs of providing delivery service; and
5. A measure of "normal weather" (other than the thirty-year measure of normal weather computed by the National Oceanographic and Atmospheric Administration, or "NOAA") that is an accurate predictor of the weather expected by the utility in future years and a reasonable basis for deriving the gas utility's normalized sales volume in its rate case.[489]

C. The Advent of Revenue Decoupling

Overall, there is a growing recognition and endorsement in the utility industry of ratemaking approaches that "decouple" a utility's sales from its revenues. As of 2002, there were only three states that had approved revenue decoupling mechanisms for gas utilities – and currently there are thirteen states that have approved revenue decoupling, and five states that have approved SFV rate design (another form of decoupling), with a number of other states currently addressing revenue decoupling issues.[490] Tables 1 and 2 present listings of the revenue decoupling mechanisms and SFV rate designs that have been approved for LDCs by state regulators.

488. Forecasted Patterns in Residential Natural Gas Consumption, 2001-2020, American Gas Association, EA 2004-04 (2004); Forecasted Patterns in Residential Natural Gas Consumption, 1997-2001, American Gas Association, EA 2003-01 (2003)(On average, natural gas use per customer in the U.S. has been declining by about one percent per year since 1980.); Joutz, Frederick & Robert P. Trost, An Economic Analysis of Consumer Response to Natural Gas Prices, American Gas Association (2007)(Weather adjusted use per customer fell by 13.1% from 2000 through 2006, the annual rate of decline in the 2000-2006 timeframe more than doubled relative to the pre-2000 period – increasing to 2.2% annually, and further acceleration was witnessed in the 2004-2006 period, as evidenced by a 4.9% annual rate of decline.)

489.

490. See Tables 1 and 2 attached.

In the regulatory area, the Kansas Corporation FERC is conducting a generic investigation into energy efficiency programs and the associated "incentive mechanisms" – including revenue decoupling.[491] The Massachusetts Department of Public Utilities is conducting an investigation into rate structures (including revenue decoupling), "that will promote efficient deployment of demand resources."[492] In Nevada, the Nevada Public Utilities FERC is conducting a proceeding in which it is reviewing the requirements of Senate Bill 437 (enacted in 2006) to adopt regulations to establish methods and programs that remove disincentives that discourage LDCs from supporting energy conservation.[493] Finally, in New Hampshire and Delaware, the utility FERCs are investigating energy efficiency rate structures and revenue decoupling for electric and gas utilities.[494]

In the legislative area, there is pending legislation in Michigan (House Bill No. 5525 introduced in December 2007) that allows for revenue decoupling and gas conservation measures.[495] The proposed bill allows a utility to adopt, "a symmetrical revenue decoupling true-up mechanism that adjusts for sales volumes that are above or below forecasted levels."[496]

D. Revenue Decoupling and Energy Efficiency Initiatives

With the increased volatility in energy prices, and the resultant unprecedented upward pressure being placed on customers' utility bills, many energy industry groups are now publicly advocating a renewed focus on promoting cost-effective energy efficiency measures to help relieve these consumer burdens. These groups include the American Gas Association (AGA), the Edison Electric Institute (EEI), the Natural Resources Defense Council (NRDC), the Alliance to Save Energy, and the American Council for an Energy Efficient Economy (ACEEE). These groups realize that a fundamental change must be made to the utility ratemaking process in order to achieve these consumer benefits. They have endorsed the concept of revenue decoupling as their solution to the problem.[497] The NRDC and the EEI made a similar joint recommendation to the NARUC in November 2003.[498]

491. General Investigation Regarding Cost Recovery and Incentives for Energy Efficiency Programs, Kan. Corp. Comm'n, Docket No. 08-GIMX-441-GIV (2000).

492. Investigation by the Department of Public Utilities on its Own Motion into Rate Structues that will Promote Efficient Deployment of Demand Resources, Commonwealth of Mass. Dep't of Pub. Util., DPU 07-50 (2005).

493. Investigation and Rulemaking, Pub. Util. Comm'n of Nev., Docket No. 07-06046 (2007).

494. Investigation into Energy Efficiency Rate Mechanisms, N. H. Pub. Util. Comm'n, Docket No. DE-07-064 (2007); In the Matter of the Investigation of Public Service FERC into Revenue Decoupling Mechanisms for Potential Adoption and Implementation by Electric and Natural Utilities Subject to the Jurisdiction of the Public Service FERC, Del. Pub. Serv. Comm'n, PSC Regulation Docket No. 59 (2007).

495. H.R. 5525, 2007 Reg. Sess. (Mich. 2007).

496. *Id.*

497. Second Joint Statement of the American Gas Association and the Natural Resources Defense Council, Nat'l Ass'n of Util. Comm'rs (NARUC) (2004).

498. D. Owens and R. Cavanagh, Letter to National Association of Regulatory Utility Commissioners, Edison Electric Institute and Natural Resources Defense Council, Nov. 18, 2003. ("To eliminate a powerful disincentive for energy efficiency and distributed-resource investment, we both support the use of modest,

NARUC has recognized revenue decoupling as a ratemaking concept that provides earnings stability for utilities and removes the disincentives for promoting energy conservation, and has made reference to the above-mentioned groups in its Resolution on Gas and Electric Efficiency - sponsored by the NARUC Natural Gas Task Force, Committee on Gas, Committee on Consumer Affairs, Committee on Electricity, Committee on Energy Resources and the Environment - adopted by the NARUC Board of Directors on July 14, 2004.[499]

In its 2005 fall meeting, NARUC adopted its Resolution on Energy Efficiency and Innovative Rate Design, sponsored by the Committee on Gas (recommended by the NARUC Board of Directors on November 15, 2005, adopted by the NARUC on November 16, 2005).[500] This resolution encouraged utility regulators to consider changes to the rate designs they had previously approved consistent with the recommendations made by the trade associations in their above-referenced statements.[501] The NARUC resolution also found that the traditional volume driven state approach to regulating the rates that utilities charge to deliver natural gas might tend to misalign the interests of natural gas utilities and the goals of energy efficiency and energy conservation. As part of this review, NARUC further encouraged state utility regulators and other policy makers to consider in their review innovative rate designs including "energy efficiency tariffs" and "decoupling tariffs."[502] The resolution recognized several utilities that have received approval of revenue decoupling mechanisms, fixed-variable rates, and other innovative rate design approaches.

The National Action Plan for Energy Efficiency[503] (Action Plan) emphasizes the need to eliminate ratemaking and regulatory disincentives or barriers through its recommendation that utility regulators "[m]odify policies to align utility incentives with the delivery of cost-effective energy efficiency and modify ratemaking practices to promote energy efficiency investments."[504] Specifically, the Action Plan states that, "[removing] the throughput incentive is one way to remove a disincentive to invest in efficiency."[505] A revenue

regular true-ups in rates to ensure that any fixed costs recovered in kilowatt-hour charges are not held hostage to sales volumes.")

499. Resolution on Gas and Electric Energy Efficiency, Nat'l Ass'n of Util. Comm'rs, 2, http://www.psc.state.ut.us/utilities/gas/05docs/05057T01/Tariff-B%2012-19.doc. (July 2004) *(*Among the mechanisms supported by these groups are the use of automatic rate true-ups to ensure the utility's opportunity to recover authorized fixed costs is not held hostage to fluctuations on (sic) retail sales.*)*

500. *Id.*

501. *Id.* ("[NARUC] . . . encourages State Commissions and other policy makers to review the rate designs they have previously approved to determine whether they should be reconsidered in order to implement innovative rate designs that will encourage energy conservation and energy efficiency that will assist in moderating natural gas demand and reducing upward pressure on natural gas prices . . ..)

502. NATIONAL ASS'N OF REGULATORY UTILITY COMM'RS, PRESS RELEASE, http://www.ase.org/content/article/detail/3901 (last visited September 22, 2008).

503. Issued in July 2005, the "Action Plan" was facilitated by the U.S. Department of Energy and U.S. Environmental Protection Agency with the participation of over 50 utilities, public utility FERCs, energy consumers, and non-governmental groups to set a broad course for encouraging greater energy efficiency investment in the United States.

504. *National Action Plan for Energy Efficiency: A Plan Developed by More than 50 leading Organizers in Pursuit of Energy Savings and Environmental Benefits Through Electric and Natual Gas Energy Efficiency, U.S. Dep't of Energy*, EPA, July 2006, at ES-2.

505. *Id.* at P 2-1.

decoupling mechanism is a ratemaking approach that can address the "Throughput Incentive" utilities have when their rates are designed so that fixed costs are recovered through volumetrically-based energy charges.

In NARUC's "Resolution Supporting the National Action Plan on Energy Efficiency" ("NARUC Resolution"), it endorsed "the principal objectives and recommendations of the Action Plan," [506] and commends to its member FERCs a state-specific, or where appropriate, regional review of the elements and potential applicability of energy efficiency policy recommendations outlined in the Action Plan, in an effort to identify potential improvements in energy efficiency policy nationwide." The NARUC Resolution cites five key elements of the Action Plan, including the modification of ratemaking practices to align utility incentives with the delivery of cost effective energy efficiency and to promote energy efficiency investments.

Section 532(b) (6) (A) of the Energy Independence and Security Act of 2007[507] states that "[t]he rates allowed to be charged by a natural gas utility shall align utility incentives with the deployment of cost-effective energy efficiency." Further, from a policy perspective, the Act directs each state regulatory authority to consider, "separating fixed-cost revenue recovery from the volume of transportation or sales service provided to the customer."[508]

E. Other Innovative Ratemaking Approaches

Besides the adoption of revenue decoupling, utility regulators also have approved ratemaking approaches for LDCs to address some of the other business challenges described earlier, including the rising cost of bad debt, the increasing requirements applicable to maintenance and improvement of aging infrastructure and system reliability, and the cost of implementing energy efficiency and conservation programs for the LDC's customers.

In the recent past, many gas utilities have experienced higher than forecasted bad debt (uncollectible accounts) expense from the significant rise in customers' gas bills caused by the unprecedented level of wholesale gas prices. The higher customer bills result in more customers being slow or unable to pay, with resultant higher delinquent balances. More and higher delinquent balances have led to greater net write-offs for the utility. Those utilities that recover bad debt expense as a fixed cost component established in their base rate cases have experienced in recent years an under-recovery of actual bad debt expenses, especially those utilities that have not had a recent rate case.

When bad debt increases on a utility system, the utility's rates only permit it to collect an amount that is based on historical experience. As a result, some LDCs have received approval to implement ratemaking solutions to this problem in the form of either: (1) a separate tracker mechanism, (2) an added component to the utility's existing purchased gas adjustment mechanism, (3) a separate

506. RESOLUTION SUPPORTING THE NAT'L ACTION PLAN ON ENERGY EFFICIENCY, NAT'L ASS'N OF REGULATORY UTIL. COMM'RS, http://www.naruc.org/Resolutions/Vision%20for%202025.pdf (last visited August 2, 2006).

507. Energy Independence & Security Act of 2007, Pub. L. No. 110-140, § 532, 121 Stat. 14922007.

508. *Id.*

adjustment to expenses.[509] Such ratemaking approaches have been approved by utility regulators in the states of Connecticut, Massachusetts, Maine, New Hampshire, Ohio, Rhode Island, Tennessee, Utah, Virginia, and Wyoming.[510]

To accommodate a utility's ongoing infrastructure requirements, certain gas utilities have proposed and implemented ratemaking mechanisms that enable the recovery of system integrity management costs (*e.g.*, costs mandated under the Pipeline Safety Improvement Act)[511] and the capital-related costs of pipeline replacement programs (*e.g.*, accelerated replacement of cast iron distribution mains). Under the approved ratemaking mechanisms, gas utilities are able to recover these costs are on a more current basis through either: (1) a separate tracker mechanism, (2) deferred accounting methods, or (3) treatment as a capitalized asset, or (4) a separate rate surcharge. Such ratemaking approaches have been approved by utility regulators in the states of Alabama, Arkansas, Georgia, Indiana, Kansas, Kentucky, Missouri, North Carolina, Ohio, Oregon, Texas, and Utah.[512]

Finally, to address the uncertainties associated with the level of costs associated with a utility's energy efficiency and conservation program, some utilities have received approval to implement ratemaking approaches that enable the utility to recover these costs on a current basis. According to the ACEEE, program cost recovery is considered to be "[a]n essential factor in order to achieve utility-sector energy efficiency programs."[513] There are many examples of utilities, in states such as Idaho, Illinois, Massachusetts, Minnesota, Vermont, and Washington, that have received regulatory approval to recover the direct costs of their energy efficiency and conservation programs through tariff provisions such as automatic adjustment riders or separate public benefits charges.

509. Memorandum from The Commonwealth of Massachusetts Department of Public Utilities on Rate Structures that will Promote Efficient Deployment of Demand Resources, D.P.U. 07-50 (October 5, 2007) .

510. Utility Co. Gross Earning Tax Gross Earning from Operations, Conn. Dep't of Revenue Ser's, Ruling 2000-6 (2000); Investigation by the Dept. of Pub. Util. on its own Motion into Rate Structures that will Promote Efficient Deployment of Demand Resources, Mass. Dept. of Pub. Util., DPU-07-50-A (2008); 2005 Annual Report by Pub. Util. Comm'n to Util. and Energy Comm. on Natural Gas Ratemaking Mechanisms and Actions Taken by the Comm'n Pursuant to 35-A M.R.S.A. 4706, Me. Pub. Util. Comm'n (2005), Investigation into Energy Efficient Rate Mechanisms: Order on Scope and Schedule, N.H. Pub. Util. Comm'n, Order No. 24,774 (2007); Dayton Power and Light Co.: Staff Report of Exceptions and Recommendation, Pub. Util. Comm'n of Ohio, Case No. 99-2688-EL-AAM, 14-15; Providence Gas Co. Annual Gas Charge Clause Filing, Valley Gas Co. Annual Purchased Gas Price Adjustment Clause Filing, R.I. Pub. Util. Comm'n., Docket Nos. 1673, 1736 (2001); Tenn. Regulatory Auth. Annual Report, Tenn. Regulatory Auth., 22-25 (2001); Status Report: The Development of a Competitive Retail Market for Electric Generation within the Commonwealth of Virginia, State Corp. Comm'n (2007).

511. Pipeline Safety Improvement Act of 2002, Pub. Law No. 107-355, 49 U.S.C. § 60129.

512. Table 2; *see also* Review of Utility Ratemaking Procedures, Iowa Util's Bd. (2004).

513. AMERICAN COUNCIL FOR AN ENERGY EFFICIENT ECON., ALIGNING UTILITY INTERESTS WITH ENERGY EFFICIENCY OBJECTIVES: A REVIEW OF RECENT EFFORTS AT DECOUPLING AND PERFORMANCE INCENTIVES, U061, http://aceee.org/pubs/u061.pdf?CFID=1852415&CFTOKEN=64914453 (2006).

Table 1
Approved Revenue Decoupling Mechanisms

Utility	State	Year Approved	Case Number
CenterPoint Energy	AR	2007	Docket No. 06-161-U
Arkansas Western Gas	AR	2007	Docket No. 06-124-U
Arkansas Oklahoma Gas	AR	2007	Docket No. 07-026-U
Pacific Gas and Electric	CA	2002	Application No. 02-02-012
San Diego Gas and Electric	CA	2002	Application No. 02-02-012
Southern California Gas	CA	2002	Application No. 02-02-012
Southwest Gas	CA	2002	Application No. 02-02-012
Public Service Company of Colorado	CO	2007	Docket No. 06-656-G
Peoples Gas Light and Coke Company	IL	2008	Docket No. 07-0242
North Shore Gas Company	IL	2008	Docket No. 07-0241
Vectren Indiana (2 utilities)	IN	2006	IURC Cause No. 42493
Citizens Gas & Coke Utility	IN	2007	IURC Cause No. 42767

Table 2
Approved SFV Rate Design

Utility	State	Year Approved	Case Number
Oklahoma Natural Gas	OK	2005	Cause No. PUD 200400610
Xcel Energy	ND	2005	Case No. PU-04-578
AGL Resources	GA	2001	Docket No. 8390-U
Missouri Gas Energy	MO	2007	Case No. GR-2006-0422
Atmos Energy	MO	2007	Case No. GR-2006-0387
Duke Energy Ohio	OH	2008	Case No. 07-589-GA-AIR