REPORT OF THE NATURAL GAS REGULATION COMMITTEE

This Report summarizes several major natural gas decisions and policy developments that have occurred at the Federal Energy Regulatory Commission (FERC or Commission) and the U.S. Courts of Appeals, plus the gas-related provisions of the Energy Policy Act of 2005. The timeframe covered is the period since the last Report of the Committee, at year-end 2004. Below is an index of the major subjects covered:

I. EPACT 2005 NATURAL GAS PROVISIONS AND FERC PENALTY AUTHORITY

The Energy Policy Act of 2005 (EPAct 2005),[1] enacted on August 8, 2005, is the first piece of wide-ranging energy legislation passed by Congress in over a decade. The Act contains several provisions of interest to the natural gas industry, including increased FERC penalty and rulemaking authority to discourage and punish manipulation of the wholesale natural gas market, and primary jurisdiction under the Natural Gas Act (NGA)[2] for the FERC to permit, site and approve onshore liquefied natural gas (LNG) import terminals.

A. FERC Anti-Manipulation and Penalty Authority

Section 315 of the EPAct 2005 empowered the FERC with authority to enact anti-manipulation rules for participants in natural gas marketing and trading.[3] The FERC exercised that authority in issuing its new anti-manipulation rule prohibiting:

> any entity, directly or indirectly, in connection with the purchase or sale of natural gas or the purchase or sale of transportation services subject to the jurisdiction of the Commission, . . . (1) [T]o use or employ any device, scheme, or artifice to defraud, (2) [T]o make any untrue statement of a material fact or to omit to state a material fact necessary in order to make the statements made, in the light of the circumstances under which they were made, not misleading, or (3) [T]o engage in

1. Energy Policy Act of 2005, Pub. L. No. 109-58, 119 Stat. 594.
2. 15 U.S.C. § 717(b) (2000).
3. Energy Policy Act of 2005 § 315.

> any act, practice, or course of business that operates or would operate as a fraud or deceit upon any [entity].[4]

The anti-manipulation provisions of the EPAct 2005 were written to "closely track the prohibited conduct language in section 10(b) of the Securities Exchange Act of 1934,[5] and specifically dictate that the terms 'manipulative or deceptive device or contrivance' are to be used 'as those terms are used in section 10(b) of the Securities Exchange Act of 1934.'"[6] This modeling of the FERC's new rule after the language of Rule 10b-5 under the Securities Exchange Act of 1934 "will benefit entities subject to the new rule because there is a substantial body of precedent applying the comparable language" that, in the Commission's view, provides an appropriate analogy for interpretation of the new rule.[7] The Commodity Futures Trading Commission's (CFTC's) anti-fraud rule[8] under section 4(b) of the Commodity Exchange Act is also meant to provide some interpretive guidance for the new rule.[9]

The effect of the new rule is far-reaching, applying to "any entity"[10] who manipulates the natural gas market in connection with a jurisdictional transaction. The Commission interprets the EPAct 2005's use of "any entity" to mean "any person or form of organization, regardless of its legal status, function or activities."[11] The FERC's authority does not extend, however, to fraudulent or manipulative behavior in connection with a "non-jurisdictional transaction (such as a first or retail sale) . . . ."[12]

To provide "firm but fair enforcement"[13] of FERC rules and regulations, the EPAct 2005 greatly enhanced the FERC's criminal and civil penalty authority against violations of the NGA,[14] Natural Gas Policy Act of 1978 (NGPA),[15] Federal Power Act (FPA),[16] and Interstate Commerce Act (ICA).[17] The EPAct 2005 made several substantial changes to the FERC's civil penalty authority:

> First, Congress expanded the Commission's FPA civil penalty authority to cover violations of any provision of Part II of the FPA, as well as of any rule or order issued thereunder. Second, Congress extended the Commission's civil penalty authority to cover violations of the NGA or any rule, regulation, restriction, condition, or order made or imposed by the Commission under NGA authority.

4. Order No. 670, *Prohibition of Energy Market Manipulation*, 114 F.E.R.C. ¶ 61,047 (2006), 71 Fed. Reg. 4244 (2006) (to be codified at 18 C.F.R. pt. 1c) [hereinafter Order No. 670].

5. 15 U.S.C. 78j(b) (2000).

6. Order No. 670, *supra* note 4, at P 6.

7. *Id.* at P 7.

8. 7 U.S.C. § 6(b) (2000).

9. Notice of Proposed Rulemaking, Prohibition of Energy Market Manipulation, F.E.R.C. STAT & REGS ¶ 32, 591 at P 13, 70 Fed. Reg. 61,930 (2005).

10. Order No. 670, *supra* note 4, at PP 16-18.

11. *Id.* at P 18.

12. Order No. 670, *supra* note 4, at P 16.

13. *Enforcement of Statutes, Orders, Rules, and Regulations*, 113 F.E.R.C. ¶ 61,068 at P 1 (2005) [hereinafter *Enforcement of Statutes*].

14. 15 U.S.C. § 717 (2000).

15. 15 U.S.C. §§ 3301 (2000).

16. 16 U.S.C. § 791a (2000).

17. 49 Cong. Ch. 104, 24 Stat. 379 (1887).

> Third, Congress established the maximum civil penalty the Commission may assess under the NGA, NGPA, or Part II of the FPA as $1,000,000 per violation for each day that it continues.[18]

The EPAct 2005 also provided a significant increase in the FERC's criminal penalty authority under section 21 of the NGA and section 504(c) of the NGPA.[19] Maximum fines for a criminal penalty were increased from $5,000 per day to $1,000,000 per day.[20] Maximum imprisonment time was increased from two years to five years.[21] The FERC's authority is limited to civil enforcement but it may refer criminal matters to the Department of Justice for prosecution.[22]

Similar to the Securities Exchange Commission (SEC) and CFTC, the FERC determines its remedies for violations on a case-by-case basis.[23] "It is important that [the FERC] retain the discretion and flexibility to address each case on its merits, and to fashion remedies appropriate to the facts presented, including any mitigating factors."[24] When determining penalties, section 316A of the FPA and new section 22 of the NGA require that the FERC first consider "the seriousness of the offense."[25] The factors used in determining the seriousness of the offense are outlined in the FERC's Policy Statement on Enforcement, issued October 20, 2005, and may include: (1) the harm caused by the violation, (2) whether the actions creating the violation stemmed from manipulation, deceit or artifice and were willful, (3) the entity's history of violations, (4) whether the violation involved actions or knowledge by senior management, (5) and the effect of penalties on the financial viability of the violator.[26] Next, the FERC considers the steps taken, if any, to "remedy the violation in a timely manner. This aspect of the company reaction to wrongdoing involves what consideration will be given for steps taken by entities to prevent, monitor, and immediately stop misconduct, to report violations to the Commission, and to cooperate with the Commission's enforcement action[]."[27] The FERC places a high value on companies which proactively make efforts toward compliance, self-reporting, and cooperation with enforcement activities.[28] "[W]here many of the positive factors of internal compliance, self-reporting, and cooperation are present, [the Commission] will take those factors into account in determining the appropriate penalties for violations."[29]

B. LNG Import Facility Regulation

The EPAct 2005 clearly sets forth the Commission's role in regulation of LNG import terminal facilities, granting the FERC "exclusive authority to

18. *Enforcement of Statutes*, *supra* note 13, at P 5.
19. Energy Policy Act of 2005, Pub. L. No. 109-58, § 314, 119 Stat. 594.
20. *Id.*
21. Energy Policy Act of 2005 § 314.
22. *Enforcement of Statutes*, *supra* note 13, at P 5.
23. *Id.* at P 13.
24. *Enforcement of Statutes*, *supra* note 13, at P 13.
25. *Id.* at P 20.
26. *Enforcement of Statutes, Orders,Rules and Regulations*, 113 F.E.R.C. ¶ 61,068 at P 20 (2005).
27. *Id.* at P 21.
28. *Enforcement of Statutes*, *supra* note 13, at P 21.
29. *Id.* at P 29.

approve or deny an application for the siting, construction, expansion, or operation of an LNG terminal”[30] while noting that nothing in the EPAct 2005 is intended to affect States’ rights under the Coastal Zone Management Act of 1972,[31] the Clean Air Act,[32] or the Federal Water Pollution Control Act.[33] Section 311(d) of the Act requires the Governor of the State where the LNG terminal is to be located to designate a state agency for consultation on “State and local safety considerations”[34] with the Commission prior to issuance of section 3 NGA authorization.[35] The State agency may also issue an advisory report on state and local safety considerations no later than thirty days after filing of the application.[36] The Commission is required to review and respond to the advisory report prior to authorizing siting, construction, expansion, or operation of the LNG terminal under section 3 NGA.[37] Once the terminal is operational, the State also maintains the right to conduct safety investigations upon written notice to the Commission and to report any alleged safety violations.[38]

The EPAct 2005 also codifies the Commission’s decision in *Hackberry LNG Terminal, L.L.C.* (*Hackberry*)[39] regarding a shift in policy from open access regulation to market-based rates for LNG import terminals. In *Hackberry*, the FERC granted authorization for a new LNG import terminal to operate as a non-open access facility, eliminating the need for a tariff and rate schedule as part of its section 3 NGA authorization.[40] The Commission’s goal in separating LNG import terminals from open-access regulated interstate natural gas pipelines was to provide incentives for the development of additional energy infrastructure that could “increase much-needed supply into the United States, while at the same time ensuring competitive commodity prices . . . .”[41] The NGA notes that codification of the *Hackberry* policy is not meant to change the open access service provided currently to customers of existing LNG terminals.[42]

The EPAct 2005 also changes the FERC’s voluntary pre-filing process for filing an application for authorization to site and construct an LNG terminal to a mandatory procedure, requiring an applicant to begin the pre-filing process at least six months before filing an application for project approval under section 3 of the NGA.[43] Prior to the EPAct 2005, the pre-filing process was a voluntary option to encourage informal and open communication between the applicant and the Commission, state and local officials, and non-governmental

30. 15 U.S.C. § 717b(e)(1) (2000).
31. 16 U.S.C. § 1451 (2000).
32. 42 U.S.C. § 7401 (2000).
33. 33 U.S.C. § 1251 (2000).
34. 15 U.S.C. § 717b-1(b) (2000).
35. *Id.*
36. 15 U.S.C. § 717b-1(c) (2000).
37. *Id.*
38. 15 U.S.C. § 717b-1(d) (2000).
39. *Hackberry LNG Terminal, L.L.C.*, 101 F.E.R.C. ¶ 61,294 (2002).
40. *Id.* at PP 3, 26.
41. 101 F.E.R.C. ¶ 61,294 at P 23.
42. 15 U.S.C. § 717b(e)(4) (2000).
43. 15 U.S.C. § 717b-1(a) (2000).

stakeholders.[44] After success with the voluntary pre-filing process in the past several years,[45] the EPAct 2005 makes pre-filing for new LNG import terminal applications mandatory. The pre-filing requirement also applies to modifications to existing or authorized LNG terminal projects "if such modifications involve significant state and local safety considerations that have not been previously addressed."[46] The new pre-filing rule allows applicants for other facilities subject to FERC jurisdiction under the NGA to use the pre-filing process on a voluntary basis.[47]

II. D.C. CIRCUIT DECISION IN *AGA V. FERC*

On October 28, 2005, in *American Gas Ass'n v. FERC*,[48] the United States Court of Appeals for the District of Columbia Circuit ruled on two significant issues that remained unsettled from natural gas pipeline restructuring: (1) term caps on the regulatory right of first refusal (ROFR), and (2) the Commission's policy to permit backhaul and forwardhaul transactions in the secondary market. Both of these issues had been addressed in the court's prior opinion in *Interstate Natural Gas Ass'n of America v. FERC* (*INGAA*),[49] which remanded for further consideration the issue of whether the FERC's pre-granted abandonment scheme "appropriately balance[s] the protection of captive customers with the furtherance of market values . . . ."[50] In addition, the court had remanded to the Commission its decision to permit backhaul and forwardhaul deliveries "to a single point in an amount greater than the shipper's contracted-for capacity at [that] point."[51]

A. Elimination of the Matching Term Cap Upheld

The Commission first established the ROFR as a condition for pre-granted abandonment authority under section 7(b) of the NGA.[52] In Order No. 636,[53] the Commission established that a long-term firm shipper could continue its historic service, subject only to matching conditions on rates and contract terms offered by competing bidders.[54] At that time, the Commission placed a cap of

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44. 42 U.S.C. § 4321 (2000).

45. Order No. 665, *Regulations Implementing Energy Policy Act of 2005; Pre-Filing Procedures for Review of LNG Terminals and Other Natural Gas Facilities*, [Regs. Preambles 2001-2005] F.E.R.C. STATS. & REGS. ¶ 31,195 (2005), 70 Fed. Reg. 60,426 (2005) (to be codified at 18 C.F.R. pts. 153, 157, 375) [hereinafter Order No. 665].

46. *Id.* at P 2.

47. Order No. 665, *supra* note 45, at P 2.

48. American Gas Ass'n v. FERC, 428 F.3d 255 (D.C. Cir. 2005).

49. Interstate Natural Gas Ass'n of Am., 285 F.3d 18, 29 (D.C. Cir. 2002).

50. *Id.* at 52.

51. *Interstate Natural Gas*, 285 F.3d at 40.

52. The Commission was responding to a remand of its adoption of pre-granted abandonment authority for pipeline service agreements in *American Gas Ass'n v. FERC*, 912 F.2d 1496 (D.C. Cir. 1990).

53. Order No. 636, *Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation; and Regulation of Natural Gas Pipelines after Wellhead Decontrol*,[Regs Preambles 1991-1996] F.E.R.C. STATS. & REGS. ¶ 30,939 (1992), 57 Fed. Reg. 13,267 (1992) (to be codified at 18 C.F.R. pt. 284).

54. *Id.* at pp. 30,448-50.

twenty years on the contract duration that must be matched by shippers seeking to avoid pre-granted abandonment; however, the court remanded the twenty-year cap for lack of reasoned explanation.[55] The Commission subsequently adopted a five-year cap,[56] which the court again vacated and remanded as unsupported.[57] Finally, with the issue once again on remand, the Commission eliminated the cap upon finding that its existing regulations adequately control the exercise of market power.[58]

On appeal of the FERC's elimination of the cap, shippers represented by the American Gas Association (AGA), claimed that the Commission had failed to support its conclusion that its existing regulations provided adequate protection against the exercise of market power. In response to the AGA's argument that the FERC failed to consider any data in its determination, the Commission contended that the only existing evidence, which came from regulated markets, revealed nothing about the duration of contracts in competitive markets. The court accepted this rationale, holding that the FERC had met its evidentiary requirement by showing, in the absence of a link between the contract term to the exercise of market power, there was no justification for "distorting the bidding process" by imposing a cap.[59]

Turning to the petitioners' substantive concerns, the court addressed their argument that pipelines can exercise greater market power over existing customers than over new customers through the threat of termination of service to customers who require essential pipeline services. Citing its prior decision in *Process Gas Consumers Group v. FERC*,[60] the court held that to demonstrate that pipelines exercise market power, petitioners must show that pipelines intentionally withhold capacity to gain advantages or concessions.[61]

The court also rejected petitioners' arguments that the Commission should have accounted for certain risks faced by local distribution companies (LDCs) that could force LDCs into long-term pipeline contracts without the certainty of what markets they might serve in the future. The court instead held that "FERC must protect existing shippers from market power, not from competition," and accepted the FERC's rationale that its capacity release program would permit LDCs to mitigate any business harm that might occur from the elimination of the term matching cap.[62]

B. Backhaul and Forwardhaul Segmented Transactions Upheld

The court in *AGA v. FERC* addressed another issue arising out of Order No. 636 restructuring concerning the segmentation policy and expanded flexible

55. United Distribution Co. v. FERC, 88 F.3d 1105 (D.C. Cir. 1996).

56. *Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations*, 78 F.E.R.C. ¶ 61,186, at p. 61,774 (1997).

57. Interstate Natural Gas Ass'n of Am. v. FERC, 285 F.3d 18, 52-53 (D.C. Cir. 2002).

58. *Regulation of Short-Term Natural Gas Transportation Services, and Regulation of Interstate Natural Gas Transportation Services*, 101 F.E.R.C. ¶ 61,127 at P 1 (2002).

59. American Gas Ass'n v. FERC, 428 F.3d 255, 259 (D.C. Cir. 2005).

60. Process Gas Consumers Group v. FERC, 292 F.3d 831 (D.C. Cir. 2002).

61. *American Gas*, 428 F.3d at 260.

62. *Id.* at 261.

point rights for firm shippers. In *INGAA*, the court generally upheld segmentation and flexible point rights, but remanded for further explanation the Commission's decision to allow backhaul/forwardhaul segmented transactions. Various pipelines, represented by Tennessee Gas Pipeline Company, challenged the Commission's defense of its policy on the basis that the policy modifies existing pipeline contracts by increasing shippers' delivery point entitlements and the services pipelines must provide. Thus, they argued that the policy violates the *Mobile-Sierra* standard and NGA section 7.

The court observed that, in remanding the policy, it had not directed the Commission to make *Mobile-Sierra* or section 7 findings, but instead it compelled the FERC to address whether additional findings are necessary—leaving the FERC free to determine whether the policy modified pipeline contracts. The court agreed with the FERC that out-of-path secondary firm transactions are different from the service guaranteed under the contract and are thus not covered by the contract. Thus, the court concluded that the terms of primary service for which the parties have bargained are not changed, and the FERC's decision does not modify contracts.[63]

The court also rejected petitioners' arguments that the FERC's policy expands the service pipelines must provide. Instead, the court found satisfactory the Commission's explanation that since the shipper pays the costs of the entire zone, the shipper may use all of the points in a zone for which it is paying on a secondary basis.[64]

III. US LNG Terminal Authorization (June 2004 through June 2006)

A. *On-Shore LNG Terminals*

1. *Freeport LNG Development, L.P.*—Docket No. CP03-75-000

The Freeport LNG Development, L.P. (Freeport LNG) LNG terminal (and associated pipeline project), to be located on Quintana Island, Brazoria County, Texas, was approved by the FERC on June 18, 2004, under section 3(a) of the NGA.[65] Freeport LNG's terminal, which currently is under construction, will have a send-out capacity of 1.5 billion cubic feet per day (Bcf/d).[66] The Commission approved both the LNG terminal and the pipeline under section 3 of the NGA and did not require separate section 7 authorization for the pipeline, because, as stated by Freeport LNG, the project will only serve the intrastate Texas market and will not connect with interstate pipelines.[67]

On May 26, 2005, Freeport LNG requested authorization to increase the terminal capacity from 1.5 Bcf/d to 4.0 Bcf/d.[68] On June 20, 2006, the

63. *American Gas*, 428 F.3d at 262.

64. *Id.* at 263.

65. *Freeport LNG Dev., L.P.*, 107 F.E.R.C. ¶ 61,278 at P 1 (2004).

66. *Id.* at P 2.

67. *Freeport LNG Dev., L.P.*, 107 F.E.R.C. ¶ 61,278 at P 2.

68. Letter from Freeport LNG Development L.P. to Magalie Salas (May 26, 2005), APPLICATION FOR AUTHORIZATION TO SITE, CONSTRUCT AND OPERATE LIQUEFIED NATURAL GAS IMPORT FACILITIES (Docket

Commission issued an Environmental Assessment for the expansion project. Authorization of the expansion project currently is pending.[69]

2. *Sabine Pass LNG, L.P.*—Docket Nos. CP04-47-000 and CP05-396-000

***Cheniere Sabine Pass Pipeline Company*—Docket Nos. CP04-38-000, CP04-38-001, CP04-39-000, CP04-40-000**

The Sabine Pass LNG Terminal, to be located in Cameron Parish, Louisiana, was approved by the FERC on December 21, 2004, along with the Cheniere Sabine Pass Pipeline.[70] Sabine LNG's terminal, which is currently under construction,[71] will be able to transport up to 2.6 Bcf/d of LNG, with a total plant capacity of 2.8 Bcf/d.[72]

On June 15, 2006, the FERC approved expansion of the Sabine Pass LNG terminal, increasing its average send-out capacity from 2.6 Bcf/d to 4 Bcf/d.[73]

3. *Corpus Christi LNG, L.P.*—Docket No. CP04-37-000

***Cheniere Corpus Christi Pipeline Company*—Docket Nos. CP04-44-000, CP04-45-000, CP04-46-000**

The Corpus Christi LNG, L.P. Terminal, to be located near Corpus Christi, Texas, was approved by the FERC on April 18, 2005, along with the Cheniere Corpus Christi Pipeline.[74] The Corpus Christi LNG terminal will have the capacity to import, store, and vaporize 2,600 million cubic feet per day (MMcf/d), with an installed capacity of 2,880 MMcf/d.[75] The pipeline will have a takeaway capacity of 2,700 MMcf/day and will transport 2,600 MMcf/day of natural gas.[76] Corpus Christi's LNG terminal is currently under construction.

4. *Vista del Sol LNG Terminal LP*—Docket No. CP04-395-000

***Vista del Sol Pipeline LP*—Docket Nos. CP04-405-000, CP04-406-000, CP04-407-000**

The Vista del Sol LNG Terminal LP, to be located in San Patricio County, Texas, was approved by the FERC on June 20, 2005, along with the Vista del Sol Pipeline.[77] The Vista del Sol LNG terminal will import, store and vaporize 1.1 Bcf/d of LNG, with a peak capacity of 1.4 Bcf/d.[78] The pipeline project consists of a twenty-five mile long, twenty-six inch diameter pipeline with a

No. CP05-361-000) (2005), *available at* http://elibrary.ferc.gov/idmws/docket_search.asp (type "CP05-361" in as the "Docket Number").

69. Letter from Magalie Salas to Freeport LNG Development L.P. (June 2006), FREEPORT LNG PHASE II PROJECT ENVIRONMENTAL ASSESSMENT, (Docket No. CP05-361-000) (2006), *available at* http://elibrary.ferc.gov/idmws/docket_search.asp (type "CP05-361" in as the "Docket Number").

70. *Sabine Pass LNG, L.P.*, 109 F.E.R.C. ¶ 61,324 at P 1 (2004).

71. *Sabine Pass LNG, L.P.*, 115 F.E.R.C. ¶ 61,330 at PP 1-2 (2006).

72. *Id.* at P 5.

73. 115 F.E.R.C. ¶ 61,330 at P 3.

74. *Corpus Christi LNG, L.P.*, 111 F.E.R.C. ¶ 61,081 at P 1 (2005).

75. *Id.* at P 5.

76. 111 F.E.R.C.. ¶ 61,081 at P 8.

77. *Vista del Sol LNG Terminal LP*, 111 F.E.R.C. ¶ 61,432 at P 104 (2005).

78. *Id.* at PP 1, 5.

capacity of 1.4 Bcf/d.[79] The pipeline will run from the Vista del Sol LNG terminal to a terminus near Sinton, Texas.[80]

5. *Golden Pass LNG Terminal LP*—Docket No. CP04-386-000

***Golden Pass Pipeline LP*—Docket Nos. CP04-400-000, CP04-401-000, CP04-402-000**

The Golden Pass LNG Terminal, to be located near Sabine Pass, Texas, was approved by the FERC on July 6, 2005, along with the Golden Pass Pipeline.[81] The proposed Golden Pass LNG terminal will be a receiving terminal facility for LNG imported from Qatar, among other places.[82] The terminal is a two-phase construction project.[83] The first phase will yield a nominal capacity of 1.0 Bcf/d; during the second phase, the terminal will have an output of 2.0 Bcf/d, with a peak capacity of 2.7 Bcf/d.[84] Golden Pass Pipeline's proposal involves two thirty-six inch diameter pipelines to provide firm and interruptible transportation service for up to 2.5 Bcf/d of natural gas.[85] The pipeline will run from the Golden Pass Terminal to existing intrastate and interstate pipelines, including AEP Texoma Pipeline in Orange County, Texas, and Transcontinental Gas Pipe Line Corporation in Calcasieu Parish, Louisiana.[86]

6. *Weaver's Cove Energy, LLC*—Docket No. CP04-36-000

***Mill River Pipeline, LLC*—Docket Nos. CP04-41-000, CP04-42-000, CP04-43-000**

The Weaver's Cove Energy, LLC LNG Terminal, to be located in Fall River, Massachusetts, was approved by the FERC on July 15, 2005, along with the Mill River Pipeline.[87] The Weaver Cove LNG terminal will have a peak send-out capacity of 800 MMcf per day, supplying New England's natural gas market.[88] The Mill River pipeline project involves two twenty-four inch diameter lateral pipelines connecting the Weaver's Cove LNG terminal to two interstate pipeline facilities of Algonquin Gas Transmission Company.[89] The Commission's authorization is subject to Weaver's Cove's compliance with the environmental and security conditions listed in the order.[90]

The Commission acknowledged the "considerable opposition to the proposed project by . . . public officials [and other] members of the public," and stated that it "[has] taken a number of extraordinary steps to assure detailed

79. 111 F.E.R.C. ¶ 61,432 at P 7.

80. *Id.*

81. *Golden Pass LNG Terminal LP*, 112 F.E.R.C. ¶ 61,041 at P 105 (2005).

82. *Id.* at P 5.

83. 112 F.E.R.C. ¶ 61,041 at P 5.

84. *Id.*

85. 112 F.E.R.C. ¶ 61,041 at P 8.

86. *Id.*

87. *Weaver's Cove Energy, LLC*, 112 F.E.R.C. ¶ 61,070 at PP 1, 5 (2005), *order on reh'g*, 114 F.E.R.C. ¶ 61,058 (2006).

88. 112 F.E.R.C. ¶ 61,070 at P 9.

89. *Id.* at PP 1, 12.

90. 112 F.E.R.C. ¶ 61,070 at PP 4-5.

consideration of safety and security issues regarding both the proposed LNG import terminal and related LNG vessel operations."[91] These steps entailed the cooperative efforts of the Commission, the U.S. Coast Guard, local law enforcement agencies, and port stakeholders in developing an "initial vessel transit security plan," detailing procedures to manage the safety and security of LNG vessels moving through Narragansett Bay and unloading at the dock.[92] The Commission stated that "[t]his process was the most extensive effort ever performed prior to Commission authorization of an LNG import project, and [that the plan] [would] serve as a blueprint for evaluating future proposals."[93]

The Commission received numerous motions to intervene and protests regarding the Weaver's Cove project, involving some requests for a full evidentiary hearing on whether the project was the safest alternative.[94] The Commission denied such motions, asserting that its review of the proposed terminal had been sufficiently thorough.[95] The Commission concluded, "we are convinced that, if the project is constructed and operated in accordance with the conditions attached to [the order], the Weaver's Cove project will be safe."[96] The Commission then approved Weaver's Cove's LNG terminal as "consistent with the public interest," because Weaver's Cove's proposed terminal would serve the growing demand for natural gas in the New England area, Weaver's Cove would be responsible for all project costs, and the terminal would have limited adverse environmental effects.[97]

On January 23, 2006, the Commission issued an order on rehearing, in which it affirmed its decision to approve the Weaver's Cove project.[98] The Commission denied petitions seeking dismissal of the Weaver's Cove LNG application on the basis that the proposed terminal would conflict with recently passed federal legislation.[99] The new law prohibits federal funding for the demolition of the Brightman Street Bridge, which spans the Taunton River downstream from the proposed facility.[100] The petitioners reasoned that, with the bridge in place, LNG tankers could not service the terminal, so the Commission should dismiss the application as moot.[101] The Commission, however, explained that its July 15 order did not condition approval of the project on the demolition of the bridge.[102] The Commission also denied motions by the City of Fall River, among others, for a rehearing.[103] Fall River argued that the Commission should reconsider the Weaver's Cove project in light of

91. *Id.* at PP 3, 79.
92. 112 F.E.R.C. ¶ 61,070 at P 3.
93. *Id.*
94. *Weaver's Cove Energy, LLC*, 112 F.E.R.C. ¶ 61,070 at PP 15, 17, 18, 20 (2005).
95. *Id.* at P 25.
96. 112 F.E.R.C. ¶ 61,070 at P 32.
97. *Id.* at PP 51, 112.
98. *Weaver's Cove Energy, LLC*, 114 F.E.R.C. ¶ 61,058 (2006).
99. *Id.* at P 43-44.
100. 114 F.E.R.C. ¶ 61,058 at PP 43-44 (2005).
101. *Id.* at P 43.
102. 114 F.E.R.C. ¶ 61,058 at P 44.
103. *Id.* at P 50.

safety concerns and project alternatives.[104] The Commission dismissed the arguments and affirmed the policy stated in its *Keyspan* order, in which it stated that its most important criterion in approving an LNG terminal is that the project is "safe and secure."[105]

On May 31, 2006, the Commission issued an order granting rehearing, not on the merits of Fall River's arguments for a rehearing, but "for the limited purpose of further consideration," of Fall River's arguments.[106]

7. *Ingleside Energy Center, LLC*—Docket No. CP05-13-000

***San Patricio Pipeline, LLC*—Docket Nos. CP05-11-000, CP05-12-000, CP05-14-000**

The Ingleside Energy Center, LLC LNG Terminal, to be located near Ingleside, Texas, was approved by the FERC on July 22, 2005, along with the San Patricio Pipeline.[107] The Ingleside LNG Terminal will have a send-out capacity of 1.0 Bcf/d.[108] Ingleside's LNG terminal will be unique in two aspects from other LNG terminal proposals.[109]

> First, Ingleside proposes to include a natural gas liquids recovery unit in the design of the terminal. Ingleside states that this unit will enable the removal of a portion of the higher British thermal unit (Btu) gas components such as ethane, propane, and butane from the gas stream for sale into the liquids market. Ingleside asserts that its ability to remove liquid hydrocarbons will increase the range of LNG sources available to its LNG facility, mitigate gas compatibility problems, provide additional feedstock for the petrochemical industry, and diversify and enhance the project's revenue stream.[110]

Second, Ingleside's project will use waste heat from an existing chemical facility to vaporize the LNG.[111] "Ingleside estimates that using this source of heat for the vaporization process will conserve about 16,000 MMBtu per day of natural gas [and avoid] the release of an estimated 300 tons per year of air emissions associated with LNG regasification."[112]

The San Patricio pipeline will be a 26.4-mile, twenty-six inch diameter pipeline running from Ingleside's proposed terminal to interconnections with interstate and intrastate pipeline facilities in San Patricio County, Texas.[113] The proposed pipeline will be able to transport up to 1.0 Bcf/d of natural gas.[114]

104. *Weaver's Cove Energy, LLC*, 114 F.E.R.C. ¶ 61,058 at P 3 (2005).

105. *Id.* at P 66; *See also Keyspan LNG, L.P.*, 112 F.E.R.C. ¶ 61,028 at P 56 (2005).

106. Order Granting Rehearing for Further Consideration, *Weaver's Cove Energy, LLC*, Docket No. CP04-36-003 (2006).

107. *Ingleside Energy Center, LLC*, 112 F.E.R.C. ¶ 61,101 at PP 1, 16, 23 (2005).

108. *Id.* at PP 1, 4.

109. 112 F.E.R.C. ¶ 61,101 at P 5.

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

111. 112 F.E.R.C. ¶ 61,101 at P 6.

112. *Id.*

113. *Ingleside Energy Center, LLC*, 112 F.E.R.C. ¶ 61,101 at P 8 (2005).

114. *Id.*

8. *Creole Trail LNG, L.P.*—Docket No. CP05-360-000

***Cheniere Creole Trail Pipeline, L.P.*—Docket Nos. CP05-357-000, CP05-357-001, CP05-357-002, CP05-358-000, CP05-359-000**

The Creole Trail LNG, L.P. Terminal, to be located in Cameron Parish, Louisiana, was approved by the FERC on June 15, 2006, along with the Cheniere Creole Trail Pipeline.[115] The Creole Trail Terminal will be capable of storing "up to 640,000 cubic meters (m^3) of LNG (equivalent to over 13 Bcf of natural gas), vaporize LNG, and send out an average of 3.3 Bcf/d (with a peak rate of 3.84 Bcf/d)."[116] Creole Trail estimates the project will be ready for the 2009 winter heating season.[117] The Cheniere Creole Trail pipeline consists of a 116.8 mile, dual forty-two inch pipeline to interconnect Creole Trail's LNG terminal with interstate and intrastate pipeline systems in Louisiana.[118] The pipeline will have a capacity of 3.3 Bcf/d.[119]

9. *Dominion Cove Point LNG, LP*—Docket Nos. CP05-130-000, CP05-130-001, CP05-130-002, CP05-132-000, CP05-132-001

***Dominion Transmission, Inc.*—Docket Nos. CP05-131-000, CP05-131-001**

On June 16, 2006, the FERC authorized expansion of the existing Dominion Cove Point LNG, LP terminal, located in Calvert County, Maryland, and authorized Dominion Transmission, Inc. to construct new pipeline and storage facilities.[120]

Expansion of the Cove Point LNG terminal "will increase . . . send-out capability by 800,000 Dth/d and increase storage capacity by . . . 6.8 Bcf."[121] The expanded Cove Point LNG terminal will have a storage capacity of 14.6 Bcf and peak send-out capability of 1.8 million dekatherms per day (MMDth/d).[122] The pipeline expansion will add a 47.8-mile, thirty-six inch diameter pipeline to deliver an additional 800,000 Dth/d of natural gas to interstate pipelines.[123] The new pipeline will be located in Calvert, Prince George's and Charles Counties, Maryland.[124]

A number of parties protested the proposed LNG terminal expansion.[125] Washington Gas Light Company (WGL), a customer of Cove Point's pipeline, asked the Commission not to approve Cove Point LNG's expansion until Cove Point LNG can show that increased deliveries of LNG from Cove Point's LNG facilities will not damage WGL's infrastructure.[126] WGL blamed its recent

115. *Creole Trail LNG, L.P.*, 115 F.E.R.C. ¶ 61,331 at P 1 (2006).
116. *Id.* at PP 1, 3.
117. 115 F.E.R.C. ¶ 61,331 at P 3.
118. *Id.* at P 5.
119. 115 F.E.R.C. ¶ 61,331 at P 5.
120. *Dominion Cove Point LNG, LP*, 115 F.E.R.C. ¶ 61,337 at PP 1, 199 (2006).
121. *Id.* at P 10.
122. 115 F.E.R.C. ¶ 61,337 at P 10.
123. *Id.* at PP 2, 21-22.
124. 115 F.E.R.C. ¶ 61,337 at P 2.
125. *Id.* at P 39.
126. *Dominion Cove Point LNG, LP*, 115 F.E.R.C. ¶ 61,337 at P 40 (2006).

increase in leaks on the reactivation of Cove Point's LNG terminal in August 2003 and expressed concern that the expansion would aggravate the leak problems.[127] The Commission rejected WGL's claim and stated that the proposed expansion showed no signs of adversely impacting existing customers due to gas quality.[128]

A number of parties objected to Cove Point LNG's proposal to operate the expansion and the existing terminal at different rates and services.[129] The Commission noted:

> This is a case of first impression in which an applicant proposes *Hackberry* rate treatment for a portion of its LNG storage service while providing cost-of-service rates for its other existing customers. The proposal raises a number of issues concerning how to ensure that Cove Point LNG's existing customers will not subsidize the Cove Point LNG Terminal Expansion to provide service for one customer and that service for the existing customers will not be degraded, nor will the existing customers be discriminated against.[130]

Consequently, the Commission required that Cove Point LNG maintain separate records of costs associated with existing versus new services.[131]

10. *Port Arthur LNG, L.P.*—Docket No. CP05-83-000

***Port Arthur Pipeline, L.P.*—Docket Nos. CP05-84-000; CP05-84-001; CP05-85-000 and CP05-86-000**

The Port Arthur LNG terminal, to be located in Port Arthur, Texas, was approved by the FERC on June 19, 2006, along with the Port Arthur Pipeline.[132] The Port Arthur LNG terminal will have a send-out capacity of 1.5 Bcf/d in Phase I, increasing to 3.0 Bcf/d in Phase II.[133] Port Arthur Pipeline's project consists of two thirty-six inch diameter pipelines, one running from the site of Port Arthur's LNG terminal to interconnect with Transcontinental Gas Pipe Line Corporation's facilities in Beauregard Parish, Louisiana (Phase I); the other running from the site of the Port Arthur's terminal to interconnect with Natural Gas Pipeline Company of America's facilities in Jefferson County, Texas (Phase II).[134]

11. *Crown Landing LLC*—Docket No. CP04-411-000

***Texas Eastern Transmission, LP*—Docket No. CP04-416-000**

The Crown Landing LNG terminal, to be located in Logan Township, Gloucester County, New Jersey, was approved by the FERC on June 20, 2006, along with the Texas Eastern Transmission, LP pipeline.[135] The Crown Landing LNG terminal will be able to store up to 9.2 Bcf of natural gas, vaporize LNG,

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127. *Id.* at PP 44-48.
128. 115 F.E.R.C. ¶ 61,337 at P 43. *See* discussion *infra* Subject IV Gas Quality and Interchangeability.
129. 115 F.E.R.C. ¶ 61,337 at P 102.
130. *Id.* at P 106.
131. 115 F.E.R.C. ¶ 61,337 at P 109.
132. *Port Arthur LNG, L.P.*, 115 F.E.R.C. ¶ 61,344 at P 93 (2006).
133. *Id.* at P 4.
134. 115 F.E.R.C. ¶ 61,344 at PP 1, 6.
135. *Crown Landing LLC & Texas Eastern Transmission, LP*, 115 F.E.R.C. ¶ 61,348 at P 1 (2006).

and send out vaporized LNG at a rate of 1.2 Bcf/d (with a peak rate of 1.4 Bcf/d).[136] The Texas Eastern pipeline consists of eleven miles of thirty inch diameter pipeline, starting from Crown Landing's proposed LNG terminal to interconnect with Texas Eastern's Chester Junction station in Delaware County, Pennsylvania.[137] The pipeline's estimated capacity is 900,000 Dth/d.[138]

B. *Off-Shore LNG Terminal*

1. *Gulf Landing, L.L.C.*—Docket No. 16860

On February 16, 2005, the Secretary of Transportation issued a deepwater port license to Gulf Landing, L.L.C. (Gulf Landing) approving Gulf Landing's proposed project. The project consists of an LNG receiving, storage, and regasification facility and up to five interconnections with offshore pipelines. Gulf Landing's deepwater port will be located in the Gulf of Mexico, off the Louisiana Coast, and will have the capability to deliver up to 1.2 Bcf/d of natural gas to the offshore pipelines.[139]

IV. NATURAL GAS QUALITY AND INTERCHANGEABILITY

A. *The Commission's Policy Statement on Natural Gas Quality and Interchangeability*

Issues related to gas quality and interchangeability have been the subject of great discussion in the industry and have been the focus of Commission inquiry since the end of 2003, when a National Petroleum Council report on the natural gas industry highlighted the need for Commission and Department of Energy action on these matters.[140] The "gas quality" discussion has focused on hydrocarbon liquid dropout. The Commission explained that as unprocessed natural gas "is transported and distributed, unprocessed natural gas may experience changes in temperature and pressure which cause the heavy hydrocarbons to assume a liquid form."[141] When this phenomenon happens, "pipelines and other downstream equipment may experience inefficient operations and unsafe conditions."[142] The "interchangeability" discussion is one that considers the impact of the varying constituents in different natural gas supplies, focusing particularly on the introduction of regasified LNG into the interstate pipeline system. "As used by the gas industry historically, 'interchangeability' means the extent to which a substitute gas can safely and

136. *Id.* at PP 1, 3.

137. 115 F.E.R.C. ¶ 61,348 at PP 1 6.

138. *Id.*

139. DEPARTMENT OF TRANSP., ACTING MARITIME ADMINISTRATOR, DOCUMENT NO. USCG-2004-16860-95, DOCKET NO. 16860, SECRETARY'S DECISION ON THE DEEPWATER PORT LICENSE APPLICATION OF GULF LANDING, L.L.C., (Feb. 16, 2005).

140. *See Natural Gas Interchangeability*, 115 F.E.R.C. ¶ 61,325 at PP 11-21 (2006) (describing procedural history of gas quality and interchangeability matters leading to the policy statement) [hereinafter *Natural Gas Interchangeability*].

141. *Id.* at P 5.

142. *Natural Gas Interchangeability*, *supra* note 140, at P 5.

efficiently replace gas normally used by an end-use customer in a combustion application."[143] The analysis also has come to include a consideration of the limitations in the design of LNG storage facilities (generally used for domestic gas storage, as opposed to LNG import terminals) that could be impacted by changes in gas composition.[144]

While the Commission had addressed some gas quality and interchangeability issues on a case-by-case basis, had held industry conferences, and had encouraged the industry to reach consensus on an approach to managing these highly technical issues, there had been no overarching Commission policy or rule on gas quality and interchangeability. The Commission changed the gas quality and interchangeability landscape when, on June 15, 2006, it issued a policy statement addressing these important issues.[145] The "compelling [need] to provide policy guidance on these issues"[146] was evident. The Commission explained:

> Three factors suggest that there is a need to act now. First, processing economics can create hydrocarbon dew point problems whenever the economics shift to favor decisions not to process natural gas. Second, establishing a sound policy on gas quality and interchangeability issues now would lower a potential barrier to expected increases in LNG imports. Third, acting now will provide a firm regulatory policy basis for additional research and development on gas quality and interchangeability issues.[147]

The Commission stated that its policy statement "achieves a balanced approach by providing certainty, ensuring the safety and reliability of the nation's gas grid, and recognizing concerns about natural gas quality and interchangeability, while providing pipelines and their customers the flexibility necessary to maximize the introduction of new supply into the grid."[148] The policy statement includes provisions that apply to existing and proposed interstate pipelines, pipelines transporting gas under section 311 of the Natural Gas Policy Act, and companies filing for authorization under section 7 of the NGA.[149]

For interstate pipelines, the Commission stated that its policy on gas quality and interchangeability "embodies five principles":

"[(1)] only natural gas quality and interchangeability specifications contained in a Commission-approved gas tariff can be enforced";[150]

"[(2)] tariff provisions on gas quality and interchangeability need to be flexible" to "allow pipelines to balance safety and reliability concerns with the importance of maximizing supply, while recognizing the evolving nature of the science underlying gas quality and interchangeability specifications";[151]

143. *Id.* at P 7.
144. *Natural Gas Interchangeability*, *supra* note 140, at P 7.
145. *Id.* at P 1.
146. *Natural Gas Interchangeability*, *supra* note 140, at P 25.
147. *Id.* (footnote omitted).
148. *Natural Gas Interchangeability*, *supra* note 140, at P 24.
149. *Id.* at PP 44-46.
150. *Natural Gas Interchangeability*, *supra* note 140, at P 29.
151. *Id.* at P 30.

"[(3)] pipelines and their customers should develop gas quality and interchangeability specifications. . . . based upon sound technical, engineering and scientific considerations";[152]

"[(4)] in negotiating technically based solutions, pipelines and their customers are strongly encouraged to use the NGC+ interim guidelines as a common scientific reference point for resolving gas quality and interchangeability issues";[153] and,

> [(5)] to the extent pipelines and their customers cannot resolve disputes over gas quality and interchangeability, those disputes can be brought before the Commission to be resolved on a case-by-case basis, on a record of fact and technical review. In resolving any such disputes, the Commission will give significant weight to the NGC+ interim guidelines.[154]

With respect to the hydrocarbon liquid dropout issues, the Commission encouraged pipelines to use either of two valid methods, the CHDP method or the C6+ GPM method, which were considered in the White Paper on Liquid Hydrocarbon Dropout in Natural Gas Infrastructure, PL04-3-000 (Jul. 21, 2004), and are discussed below.[155] For interchangeability, the Commission stated that pipelines are encouraged to use the approach described in the White Paper on Natural Gas Interchangeability and Non-Combustion End Use, PL04-3-000 (Feb. 28, 2005) (Interchangeability White Paper), which is focused on a maximum Wobbe number, heating value, butanes+ amount, and total inerts percentage, and is described further below.[156] The Commission noted that the precise provisions for each pipeline were fact-specific matters that needed to take into account each pipeline's and its customers' particular operational requirements, while ensuring that gas quality provisions would not inappropriately impede the availability of gas supply. Further, the Commission stated that pipelines had a degree of discretion to determine when it is appropriate to waive gas quality and interchangeability requirements and encouraged pipelines to allow blending of gas supplies of varying characteristics to meet gas quality and interchangeability needs.[157]

The Commission's pipeline gas quality and interchangeability policies also apply to section 311 pipelines. "As a general principle, the Commission expects that each Section 311 transporter will include specific provisions in its statement of operating conditions governing gas quality and interchangeability."[158]

For companies applying solely for NGA section 3 authorization, such as LNG terminal operators, the policy applies differently. Section 3 "[a]pplicants should include information in their application which demonstrates the compatibility of their imports with the gas quality and interchangeability requirements of all interconnecting pipelines."[159] Even though commenters requested the Commission to impose specific obligations on LNG project

152. *Natural Gas Interchangeability*, *supra* note 140, at P 31.

153. *Id.* at P 32.

154. *Natural Gas Interchangeability*, *supra* note 140, at P 33.

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

156. *Natural Gas Interchangeability*, *supra* note 140, at PP 36-38.

157. *Id.* at PP 39-41.

158. *Natural Gas Interchangeability*, *supra* note 140, at P 44.

159. *Id.* at P 46.

developers with respect to merchantability, identification of adverse impacts, compensation for negative impacts, and mitigation, the Commission found these issues to be more appropriately addressed, if and when identified, within the context of a specific proceeding.[160]

B. NGC+ Work Group and its White Papers

The Commission's policy statement expressly referred to and is generally supportive of the work included in two white papers that were the result of work done by two industry work groups operating under the leadership of the Natural Gas Council (NGC+).

1. Natural Gas Interchangeability and Non-Combustion End Use

On February 28, 2005, the NGC+ Work Group published its Interchangeability White Paper.[161] The NGC+ Work Group discussed three alternatives for managing interchangeability: at the production source, prior to introduction into the pipeline system, and at the point of end use.[162] Additionally, the NGC+ Work Group recognized the need to examine how changes in natural gas composition affect end use equipment and combustion technology.[163] The NGC+ Work Group "sought to define an approach . . . that addressed the full range of effects and that could ultimately achieve [its] objective . . . to '*[d]efine acceptable ranges of natural gas that can be consumed by end users while maintaining safety, reliability, and environmental performance*.'"[164]

Taking the above-mentioned issues into consideration, and drawing upon European experiences, the NGC+ Work Group developed an operating regime to define acceptable natural gas interchangeability limits.[165] Starting with the Wobbe Index,[166] which is considered the most robust single parameter, the NGC+ Work Group defined an upper Wobbe Index.[167] The NGC+ Work Group acknowledged that laboratory testing and combustion theory shows that a maximum Wobbe Index, in itself, is insufficient to address incomplete combustion issues over a range of gas compositions, especially those natural gas

160. *Natural Gas Interchangeability*, *supra* note 140, at P 47.

161. NATURAL GAS COUNCIL PLUS INTERCHANGEABILITY WORK GROUP, WHITE PAPER ON NATURAL GAS INTERCHANGEABILITY AND NON-COMBUSTION END USE (2005), http://www.beg.utexas.edu/energyecon/lng/documents/NGC_Interchangeability_Paper.pdf [hereinafter WHITE PAPER].

162. *Id.* at 13-17.

163. WHITE PAPER, *supra* note 161, at 8-10.

164. *Id.* at 10. The goal is to establish interchangeability standards that will maximize flexibility for acceptable natural gas supplies while maintaining safety, reliability, and environmental performance. WHITE PAPER, *supra* note 161, at 10, 25.

165. *Id.* at 12.

166. The Wobbe Index is "based on energy input and specific gravity." *Natural Gas Interchangeability, supra* note 140, at P 8. *See also* WHITE PAPER, *supra* note 161, at 30 (describing the derivation of the Wobbe Index).

167. WHITE PAPER, *supra* note 161, at 12. A maximum Wobbe Index will control the effects of combustion phenomena such as yellow tipping, incomplete combustion, and the potential for increased emissions of NO_x and CO. Similarly, a minimum Wobbe Index will control lifting, blowout, and CO. *Id.* at 13.

supplies with heating values in excess of about 1110 Btu/scf.[168] However, the NGC+ Work Group determined that it could overcome this Wobbe Index limitation by identifying a more conservative maximum Wobbe Index and by coupling the maximum Wobbe Index with a complimentary parameter.[169] The NGC+ Work Group chose heating value as its secondary parameter.[170] The NGC+ Work Group presented a pictorial representation of its operating regime as an "interchangeability box."[171]

In addition to the Wobbe Index and heating value limitations, the NGC+ Work Group further constrained the interchangeability standards by limiting the Wobbe Index range to plus or minus four percent from the specific pipeline's historical average gas supply, by limiting butane plus to 1.5 mole percent, and by limiting total inerts to four mole percent.[172]

Along with its proposed interchangeability guidelines, the NGC+ Work Group reported its findings and recommendations[173] and asserted several caveats regarding the proposed interchangeability guidelines[174] in its White Paper. The first caveat indicated that the proposed interchangeability guidelines were developed for new gas supplies in market areas that lacked experience with Wobbe Indices greater than 1400 or heating values higher than 1110 Btu/scf.[175] The second caveat indicated that the proposed interchangeability guidelines were for use in market areas with historical gas supplies similar to annual average composition data reported in the 1992 GRI report.[176] And finally, the NGC+ Work Group recommended that its proposed interchangeability guidelines should apply until "additional research and/or experience [ ] clearly demonstrate[s] that [natural gas] supplies [with compositional characteristics] above the caps do not negatively impact end users . . . ."[177]

168. WHITE PAPER, *supra* note 161, at 12-13.

169. *Id.* at 13.

170. WHITE PAPER, *supra* note 161. The NGC+ Work group noted that "[t]he 'art' is in selecting additional parameters to address the remaining end use effects" and that "[e]xperience has shown that specifying a maximum [h]eating [v]alue can address auto-ignition (or knock), flashback, combustion dynamics, and when coupled with the Wobbe [Index], incomplete combustion and sooting." *Id.* at 13. The NGC+ Work Group also noted that it found limiting a specified fraction of hydrocarbons (such as butanes plus) can address these same effects as well. WHITE PAPER, *supra* note 161, at 13.

171. *Id.* at 12 (figure 1).

172. WHITE PAPER, *supra* note 161, at 27. The NGC+ Work Group provided for an exception to its guidelines: "Service territories with demonstrated experience with supplies exceeding these Wobbe [Indices], Heating Value and/or Composition Limits may continue to use supplies conforming to this experience as long as it does not unduly contribute to safety and utilization problems of end use equipment." *Id.* at 27. In other words, the NGC+ Work Group stated that the guidelines were developed for new gas supplies into market areas that lacked experience with gas supplies with Wobbe Indices exceeding 1400 or heating values exceeding 1110 Btu/scf. WHITE PAPER, *supra* note 161, at 26.

173. *Id.* at 17-24.

174. WHITE PAPER, *supra* note 161, at 26.

175. *Id.*

176. WHITE PAPER, *supra* note 161, at 26.

177. *Id.*

2. Liquid Hydrocarbon Drop Out in Natural Gas Infrastructure

On February 28, 2005, the NGC+ Liquid Hydrocarbon Drop Out Task Group (NGC+ Task Group) published its White Paper on Liquid Hydrocarbon Drop Out in Natural Gas Infrastructure.[178] In its paper, the NGC+ Task Group described hydrocarbon liquid drop out as well as how to measure it and how it impacts various natural gas stakeholders.[179] The NGC+ Task Group also explained hydrocarbon dew points, including thermodynamic principles governing the behavior of natural gas compounds, as well as how to measure or estimate a natural gas dew point.[180]

The NGC+ Task Group made several technical recommendations. Notably, the NGC+ Task Group found cricondentherm HDP or C6+ GPM as valid parameters to control hydrocarbon liquid dropout, favoring cricondentherm HDP because of its greater operational flexibility to all stakeholders.[181] Utilizing either parameter, the NGC+ Task Group recommended that the pipeline operator establish a plan to periodically validate the underlying assumptions.[182] In addition, the NGC+ Task Group determined that using the Bureau of Mines method for determining HDP was not a practical approach for automated applications.[183]

The NGC+ Task Group also recognized that parties may be able to change control parameter limits based on other variables such as ambient conditions, storage operations, meter station and system pressure drops, and the tolerance for heavy hydrocarbon levels within a specific market area.[184]

Several other recommendations and findings were made. The NGC+ Task Group recommended that additional research should be conducted, including areas such as C6+ split assumptions, developing correlative data and improving the accuracy of some data, and developing a cost-effective hydrocarbon-specific direct-reading dew point analyzer.[185] The NGC+ Task Group found that HDP limits do not presume that gas is interchangeable.[186] And finally, the NGC+ Task Group identified thirteen items thought to be useful in establishing the cricondentherm HDP or C6+ GPM so as to avoid hydrocarbon liquid dropout.[187]

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178. NATURAL GAS COUNCIL PLUS LIQUID HYDROCARBON DROP OUT TASK GROUP, WHITE PAPER ON LIQUID HYDROCARBON DROPOUT IN NATURAL GAS INFRASTRUCTURE (2004), http://www.beg.utexas.edu/energyecon/lng/documents/NGC_HDP_Paper.pdf [hereinafter HDP WHITE PAPER].

179. *Id.* at 10-22.

180. HDP WHITE PAPER, *supra* note 178, at 23-33.

181. *Id.* at 27.

182. HDP WHITE PAPER, *supra* note 178, at 27.

183. *Id.* at 28.

184. HDP WHITE PAPER, *supra* note 178, at 28.

185. *Id.*

186. HDP WHITE PAPER, *supra* note 178, at 28.

187. *Id.* at 29.

C. Current Regulatory Proceedings

1. *Dominion Cove Point LNG, L.P.* (Docket Nos. CP05-130-000, CP05-132-000) and *Dominion Transmission, Inc.* (Docket Nos. CP05-131-000, PF04-15-000)

On April 15, 2005, Dominion Cove Point LNG, LP (Cove Point LNG) filed a section 3 NGA application to request authority to expand its facilities at its LNG import terminal in Cove Point, Maryland. Washington Gas Light Company (WGL), a local distribution company and captive customer of the pipeline extending from the Cove Point LNG terminal, filed an intervention asserting that the Commission "should deny Cove Point LNG's expansion application until such time as Cove Point LNG demonstrates that it has minimized the potential adverse impacts to WGL's infrastructure from increased deliveries of regasified LNG."[188] Specifically, WGL alleged that a high incidence of compression coupling leaks on its system in recent years were a result, in part, of shrinking of elastomer seals inside its compression couplings due to re-introduction of low C_5+ gas on its system in association with the re-activation of the Cove Point LNG terminal in December 2003. In issuing Cove Point LNG's section 3 authorization for the expansion, the Commission stated it:

> does not believe that the evidence is to demonstrate conclusively that the gas composition of the unblended, regasified LNG from the Cove Point LNG Terminal can be ruled out entirely as a contributing factor to the increase in gas leaks [on the WGL system]. However, it is clear that any shrinkage [of seals] due to the desorption of C5+ was small, particularly when compared to other contributing factors . . . and would not have caused any increase in leak rates on WGL's system in the absence of those other more significant contributing factors, namely, the application of hot tar, increase in operating pressure and a decrease in temperatures.[189]

2. AES Ocean Express, LLC v. Florida Gas Transmission Company (Docket No. RP04-249-001)

This case originated in April 2004 within the context of a proposed interconnection agreement between an LNG project developer (AES Ocean Express, LLC) and the pipeline that will receive the regasified LNG (Florida Gas Transmission Company). The purpose of the hearing was to establish the appropriate natural gas interchangeability standards to accommodate the introduction of re-gasified LNG into the Florida Gas Transmission Company (FGT) pipeline system.[190] In December 2005, the Presiding Administrative Law Judge (ALJ) held a two-week evidentiary hearing.

On April 11, 2006, the ALJ issued his initial decision.[191] The ALJ essentially found the revised natural gas interchangeability standards, proposed

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188. *Dominion Cove Point LNG, LP*, 115 F.E.R.C. ¶ 61,337 at P 44 (2006).

189. *Id.* at P 73.

190. *AES Ocean Express LLC*, 107 F.E.R.C. ¶ 61,276 at P 26 (2004).

191. *Florida Gas Transmission Co.*, 115 F.E.R.C. ¶ 63,009 (2006).

by FGT, just and reasonable[192] because the evidence indicated that these interchangeability standards permit the gas turbines connected to the FGT system to operate safely, without violating environmental emissions standards and without voiding the turbine manufacturers warranties, while permitting the importation of a substantial amount of LNG.[193] Furthermore, the ALJ found no probative evidence indicating that these interchangeability standards for regasified LNG posed a substantial risk of leakage to the Florida local distribution systems.[194]

In May 2006, the parties submitted briefs on exceptions and briefs opposing exceptions. The case is pending before the Commission at this time.

3. *Natural Gas Pipeline Company of America* (Docket Nos. RP01-503-002, RP01-503-003)

In 2003, the Commission ordered Natural Gas Pipeline Company of America (Natural) to revise its tariff to modify the General Terms and Condition procedures for setting maximum limits on the Btu and/or dew point value of the gas entering its system.[195] Natural filed a revised tariff, which among other things, established a permanent hydrocarbon dew point safe harbor.[196] A hearing was held June and July 2005, and on December 20, 2005, the ALJ issued an initial decision, finding Natural's proposed tariff provision just and reasonable.[197]

The ALJ stated at the outset that he was ruling on only one issue—whether Natural's proposed permanent safe harbor hydrocarbon dew point figure was appropriate.[198] In making his ruling, the ALJ complied with the Commission's definition of an HDP safe harbor provision: "since the permanent safe harbor dew point level is intended to provide shippers a guarantee that gas satisfying that provision will be accepted, regardless of changing conditions on the system, it is important to establish [a] permanent safe harbor that will accommodate all conditions on Natural's system."[199] The ALJ found that Natural used an

192. *Id.* at PP 171, 176, 180-195, 197. *But see Florida Gas Transmission Co.*, 115 F.E.R.C. ¶ 63,009 at P 179 (applying the interchangeability standards to FGT's entire system). Notably, the interchangeability standards apply only to regasified LNG. *Id.* at P 197.

193. 115 F.E.R.C. ¶ 63,009 at P 171. The ALJ opined that the NGC+ Work Group's proposed interchangeability standards were a "good point of reference." *Id.* at P 140. The ALJ also opined that the turbine manufacturers' specifications or actual testing of the turbines would provide "[a] more complete and reliable set of standards . . . ." *Gas Transmission Company*, 115 F.E.R.C. ¶ 63,009 at P 141 (2006).

194. *Id.* at PP 211-218, 226(h).

195. *Natural Gas Pipeline Co. of Am.*, 102 F.E.R.C. ¶ 61,234 at PP 1-3 (2003).

196. *Id.* at P 1.

197. *Natural Gas Pipeline Co. of Am.*, 113 F.E.R.C. ¶ 63,036 (2005).

198. *Id.* at P 6.

199. 113 F.E.R.C. ¶ 63,036 at P 9 (quoting *Natural Gas Pipeline Co. of Am.*, 102 F.E.R.C. ¶ 61,234 at P 38 (2003)). The ALJ noted that he was, "bound by what the Commission previously has held: 1) Natural's blending and processing capabilities are limited and, alone, are inadequate to address foreseeable instances of liquids formation; 2) the causes of liquids formation are often beyond the control of a pipeline and, accordingly, Natural should be given flexibility to address changing conditions on its pipelines; 3) the cost of processing nonconforming rich gas must be borne by those shippers who tender such gas; 4) natural must adopt a safe harbor that accommodates all conditions on its pipeline; 5) the safe harbor level may necessarily be lower than the operational HDP level; and 6) in selecting the HDP safe harbor level for its system, Natural may

acceptable scientific, industry-approved methodology for computing its hydrocarbon dew point limits.[200] The ALJ further found Natural satisfied its burden in showing that its proposed hydrocarbon dew point safe harbor was just and reasonable because it identified a safe harbor level that will ensure safe and reliable operations under all conditions, while also maximizing the gas supply available on its system.[201] Thus, the ALJ approved Natural's fifteen degree Fahrenheit HDP safe harbor.

The parties filed briefs on exceptions and briefs opposing exceptions during the first few months of 2006. In response to the Commission's June 15, 2006, Policy Statement on Natural Gas Quality and Interchangeability (Docket No. PL04-3-000), the Producer Coalition filed a request in that docket on June 21, 2006, requesting the Commission address the pending initial decision without further delay.

4. *ANR Pipeline Company* (Docket No. RP04-435-000)

In August 2004, ANR Pipeline Company (ANR) filed revised tariff sheets proposing hydrocarbon dew point gas quality specifications.[202] A little more than a year later, ANR filed an Offer of Settlement. Comments in support of, and in opposition to, the settlement were filed, as well as reply comments. The Offer of Settlement included revised tariff sheets allowing for a fifteen degree Fahrenheit HDP safe harbor, representing the lowest hydrocarbon dew point level that ANR could impose for receipts into its system, except through an operational flow order.[203] The ALJ recommended that the Commission approve the Offer of Settlement.[204]

In response to the Commission's June 15, 2006, Policy Statement on Natural Gas Quality and Interchangeability (Docket No. PL04-3-000), the Producer Coalition filed a request in that docket on June 21, 2006, requesting the Commission to issue a decision regarding the ANR Offer of Settlement. On June 23, 2006, ANR filed a letter in Docket No. RP04-435-000 supporting the Producer Coalition's request that the Commission "expeditiously" issue an order on the merits of the Offer of Settlement.

5. *Toca Producers v. FERC*, 411 F.3d 262 (D.C. Cir. 2005)

In 2005, the D.C. Circuit heard, and decided, the Toca Producers' petition for review regarding three FERC orders.[205] The underlying issue involves whether the pipeline's tariff should be revised to provide a safe harbor gas

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consider the gas quality restrictions imposed by downstream entities. [The ALJ also cited that] the Commission's order supports Natural's need for a safety margin, as well as the importance of affording Natural substantial flexibility to address liquids formation." *Id.* at 24.

200. 113 F.E.R.C. ¶ 63,036 at P 30. Natural's witnesses relied on the NGC+ Task Group's HC White Paper as well as "Natural's actual winter experience[,] their personal experiences[,] and their familiarity with the pipeline system . . . ." *Id.* at P 28.

201. *Natural Gas Pipeline Co. of Am.*, 113 F.E.R.C. ¶ 63,036 at P 28 (2005).

202. *See ANR Pipeline Co.*, 113 F.E.R.C. ¶ 63,021 (2005).

203. *Id.* at P 7.

204. 113 F.E.R.C. ¶ 63,021 at P 52. The ALJ footnoted several points that the Commission should address if it first found that genuine issues of material fact indeed existed. *Id.* at P 52 n.29.

205. Toca Producers v. FERC, 411 F.3d 262 (D.C.Cir. 2005).

quality specification standard, for gas with a higher liquefiable hydrocarbon concentration, at receipt points downstream from the processing plants.[206]

The *Toca* court dismissed the producers' petition, finding the issue unripe.[207] The court determined that the gravamen of the producers' claim was that the pipeline tariff was unjust and unreasonable without the safe harbor gas quality specification standard. However, the court reasoned that the Commission's actions were not "sufficiently final" because the Commission had not yet determined if the producers were entitled to the relief they sought; namely, that the pipeline tariff should be revised to include a gas quality specification standard.[208] The Court determined that the producers may seek judicial review of the Commission's final order in the docket still open regarding the pipeline's proposed tariff.[209]

V. Regulations Governing the Conduct of Open Seasons for Alaska Natural Gas Transportation Projects, 18 C.F.R. Pt. 157

Order No. 2005 and Order No.2005-A

On February 9, 2005, the Commission issued Order No. 2005,[210] the Final Rule required by section 103 of the Alaska Natural Gas Pipeline Act (the Act).[211] Several requests for rehearing were filed, and on June 1, 2005, the Commission issued Order No. 2005-A. This report will refer to the Final Rule including modifications made by Order No. 2005-A on rehearing as Order No. 2005. In Order No. 2005 the Commission amended its regulations to provide for standards governing the conduct of open seasons for Alaska natural gas transportation projects.[212] The Act required that the Commission's regulations:

> include the criteria for and timing of any open seasons;[213] [] promote competition in the exploration, development, and production of Alaska natural gas; [] and[214] [] for any open season[s] for capacity exceeding the initial capacity, provide [for] the opportunity for the transportation of natural gas other than from the Prudhoe Bay and Point Thomson units.[215]

The Commission's regulations are found in 18 C.F.R. Pt. 157. The regulations apply to open seasons where binding commitments will be made for

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206. *Id.* at 264-65.

207. *Toca Producers*, 411 F.3d at 264.

208. *Id.* at 266. The court noted that the pipeline filed a proposal to review its tariff, the producers intervened in that docket, and the proceeding is still pending. *Toca Producers*, 411 F.3d at 265.

209. *Id.* at 266.

210. The original order from February 9, 2005, which was published on February 18, 2005, appears at 110 F.E.R.C. ¶ 61,095. *See also* Order No. 2005, *Regulations Governing the Conduct of Open Seasons for Alaska Natural Gas Transportation Projects*, [Regs. Preambles 2001-2005] F.E.R.C. Stats. & Regs. ¶ 31,174 (2005), 70 Fed. Reg. 8269 (2005) (to be codifed at 18 C.F.R. pt. 157) [hereinafter Order No. 2005].

211. 15 U.S.C. § 720 (2000).

212. The Act defines Alaska natural gas transportation projects as pipelines carrying Alaska natural gas, that is gas derived from the area of the State of Alaska north of 64º North Lattitude, to the Canadian border. *Id.* at § 720 (1)-(2).

213. 15 U.S.C. § 720a(e)(2)(A) (2000).

214. *Id.* at § 720a(e)(2)(B).

215. 15 U.S.C. § 720a(e)(2)(C) (2000). The Prudhoe Bay and Point Thomson units are gas fields located on Alaska's North Slope with a total of approximately 35 Tcf of known gas reserves. Order No. 2005, *supra* note 210, at n.10.

capacity on either the initial project or an expansion of an Alaska natural gas transportation project.[216] Any applicant to the Commission for a certificate of public convenience or other authorization for a proposed Alaska natural gas transportation project must demonstrate that it conducted an open season in compliance with the Commission's regulations governing open seasons, or it will be rejected as incomplete.[217]

At least ninety days prior to holding the open season, the applicant[218] must file with the Commission, for Commission approval, its detailed plan for conducting the open season, including a copy of its open season notice (the Notice).[219] The Commission will notice the request for approval in the Federal Register. Interested persons may comment on the plan, and the Commission, unless it determines otherwise, will act on the request to approve the plan within sixty days.[220] The Commission will consider its action on the plan as interlocutory, and not subject to rehearing, since any person opposing the plan will have the ability to protest the open season procedures during the certificate application process.[221] Once the plan is approved, and the Notice is given, the applicant must provide shippers at least ninety days from the Notice to submit a request for transportation.[222] No bid may be rejected due to participation in a competing open season.[223] Within ten days after precedent agreements are executed, the applicant must publish the results of the open season,[224] and within twenty days the Commission must be provided copies of the precedent agreements, and documentation related to any rejected bids.[225]

The Notice must contain significant information about the proposed pipeline to the extent known[226] by the applicant, including, but not limited to the general route, "including receipt and delivery points,"[227] "[the] [s]ize and design capacity[, and] a description of possible designs for expanded capacity,"[228] "[m]aximum allowable operating pressure and expected actual operating

216. Open Seasons for Alaska Natural Gas Transportation Projects, 18 C.F.R. § 157.30 (2005).

217. *Id.* at § 157.33.

218. Reference to the "applicant" from the time of the pre-open season request for approval, until the application for a certificate is submitted to the Commission, is a reference to a proposed applicant. 18 C.F.R. § 157.33 (2005).

219. 18 C.F.R. § 157.38 (2005).

220. *Id.*

221. Order No. 2005-A, *Regulations Governing the Conduct of Open Seasons for Alaska Natural Gas Transportation Projects*, [Regs. Preambles 2001-2005] F.E.R.C. STATS. & REGS. ¶ 31,187 at P 72 (2005), 70 Fed. Reg. 35,011 (2005) (to be codifed at 18 C.F.R. pt. 157).

222. Open Seasons for Alaska Natural Gas Transportation Projects, 18 C.F.R. § 157.34(d) (2005).

223. *Id.*

224. 18 C.F.R. § 157.34(d)(3).

225. *Id.* at § 157.34(d)(4).

226. "[T]o the extent that any item of such information is not known or determined at the time the notice is issued, the prospective applicant shall make a good faith estimate based on the best information available of all such unknown or undetermined items of required information and further, must identify the source of information relied on, explain why such information is not presently known, and update the information when and if it is later determined during the open season period . . . ." 18 C.F.R. § 157.34(c).

227. *Id.* at § 157.34(c)(1).

228. Open Seasons for Alaska Natural Gas Transportation Projects, 18 C.F.R. § 157.34(c)(2) (2005).

pressure[s]," including delivery pressures at proposed delivery points.[229] The Notice must contain estimates for the in-service date,[230] transportation rates,[231] and cost of service, including "cost allocations, rate design volumes, and rate design,"[232] and the projected date for filing the application.[233] The Notice must also set forth the proposed quality specifications,[234] terms and conditions of service,[235] and creditworthiness standards.[236] In addition, procedures applicable to the open season must be described in the Notice, including the date, if any, by which precedent agreements must be executed,[237] the methodology by which capacity will be allocated in the event of over subscription,[238] required bid information, including the nature of the bids required, whether binding or non-binding, and the form of precedent agreement and the treatment on non-conforming bids.[239] Finally the Commission inserted a catch-all requirement for the Notice. The applicant must provide:

> [a]ll information that the prospective applicant has in its possession pertaining to the proposed service to be offered, projected pipeline capacity and design, proposed tariff provisions, and cost projections, or that the prospective applicant has made available to, or obtained from, any potential shipper, including any affiliates of the project sponsor and any shippers with pre-subscribed capacity, prior to the issuance of the public notice of open season . . . .[240]

In response to a requirement of the Act,[241] the Commission also included special provisions related to a study of Alaska's in-state needs for access to the pipeline. Section 157.34(b) requires an applicant to conduct or adopt a study of gas consumption needs in the State of Alaska, and prospective points of delivery, with an estimate of how much capacity in the proposed pipeline will be used for in-state purposes. The study must be approved by an appropriate Alaska entity, and the results incorporated into the proposed design of the pipeline.[242] The Notice must include estimated transportation rates for in-state deliveries based on the study.[243]

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229. *Id.* at § 157.34(c)(3)-(4).

230. 18 C.F.R. §157.34(c)(5).

231. *Id.* at § 157.34(c)(6). An unbundled transportation rate for each delivery point must be stated.

232. 18 C.F.R. § 157.34(c)(7).

233. *Id.* at § 157.34(c)(17).

234. Open Seasons for Alaska Natural Gas Transportation Projects, 18 C.F.R. §157.34(c)(10) (2005). The applicant may not require that potential shippers process or treat their gas at any specific facility.

235. *Id.* at § 157.34(c)(11).

236. 18 C.F.R. §157.34(c)(12).

237. *Id.* at § 157.34(c)(13).

238. 18 C.F.R. § 157.34(c)(15). In the event that anchor shippers have executed pre-subscription agreements, and the pipeline cannot be redesigned to allow all qualifying open season bids to acquire capacity, then only those with pre-subscription agreements, and those matching the pre-subscription bids will be allocated.

239. *Id.* at § 157.34(c)(16).

240. Open Seasons for Alaska Natural Gas Transportation Projects, 18 C.F.R. § 157.34(c)(18) (2005).

241. 15 U.S.C. § 720a(g) (2000).

242. 18 C.F.R. § 157.34(b).

243. *Id.* at § 157.34(c)(8).

"[B]inding open seasons shall be conducted without undue discrimination or preference in the rates, terms or conditions of service."[244] Capacity awarded in an open season must be awarded "without undue discrimination or preference of any kind."[245] Therefore, the Commission will require the applicant to function independently from any marketing and energy affiliates, and imposes certain Order No. 2004 standards on applicants that are not already subject to the affiliate standards.[246] In addition, the Notice must set forth information concerning the applicant's sales and marketing units and Energy Affiliates[247] "involved in the production of natural gas in the State of Alaska" and publish relevant organizational charts.[248] The Commission specifically provides for complaints to be filed if it is believed that an applicant engaged in undue discrimination during the open season.[249]

Finally, the Commission's regulations allow it to require design changes in reviewing any application for a proposed pipeline,[250] and to require design changes in reviewing the application for voluntary expansions after the initial open season,[251] if the Commission finds them necessary to promote competition and reasonable access to the pipeline in the case of the initial project, and to ensure that some portion of the expansion capacity would be allocated to new shippers willing to sign long-term firm transportation contracts, including shippers seeking to transport natural gas from areas other than Prudhoe Bay and Point Thomson in the case of a voluntary expansion project. In the Press Release coinciding with Order No. 2005-A, the Commission stated "that any design change would not constitute a mandatory expansion of any project and that the Natural Gas Act provides FERC authority to attach to any certificate of public convenience and necessity any conditions it deems necessary to meet the public interest."[252] The design change provisions were challenged on appeal, and the appeal remains pending.[253]

VI. UPDATE ON CREDITWORTHINESS ISSUES

On June 16, 2005, the Commission issued a *Policy Statement* setting forth guidance on creditworthiness issues.[254] The *Policy Statement* provides guidance

244. 18 C.F.R. § 157.35(a).

245. *Id.*

246. 18 C.F.R. § 157.35(c)-(d).

247. Energy Affiliates has the meaning set forth in section 358.3(d) of the Commission's regulations. *Id.* at § 358.3(d).

248. Open Seasons for Alaska Natural Gas Transportation Projects, 18 C.F.R. § 157.34(c)(19)-(20) (2005).

249. *Id.* at § 157.35(b).

250. 18 C.F.R. § 157.37.

251. *Id.* at § 157.36.

252. Press Release, Federal Energy Regulatory Commission, Commission Reaffirms and Clarifies Open-Season Rules for Alaska Natural Gas Transportation Proposals (May 25, 2005), *available at* http://ferc.gov/press-room/press-releases/2005/2005-2/05-25-05-C-7.asp.

253. ExxonMobil Corp. v. FERC, No. 05-1299 (D.C. Cir. filed July 29, 2005).

254. Proposed Rule, *Policy Statement on Creditworthiness Issues for Interstate Natural Gas Pipelines and Order Withdrawing Rulemaking Proceeding*, F.E.R.C. STATS. & REGS. ¶ 31,191, 70 Fed. Reg. 37,717 (2005) (to be codified at 18 C.F.R. pt. 284) [hereinafter *Policy Statement*].

to the industry on the Commission's policy with respect to credit and how "the Commission will evaluate future proceedings involving changes to the creditworthiness provisions of pipeline tariffs."[255] The Commission opted to issue a *Policy Statement* rather than regulations establishing uniform creditworthiness standards, because, according to the Commission, the number of filings by pipelines to revise their creditworthiness standards have declined markedly, "and, in general, the circumstances in the energy industry that led to concern[s] about shippers' credit status and their effect on pipeline risk profiles have improved."[256]

Commissioner Brownell, however, filed a dissent to the *Policy Statement*.[257] She stated, "establishing mandatory electric creditworthiness principles will promote consistent practices across markets and utilities and provide customers with an objective and transparent creditworthiness evaluation. . . . I cannot support . . . mere guidance, as opposed to a binding rule."[258]

Essentially, the Commission determined that it would not standardize creditworthiness business practices, but that it would decide such issues case-by-case.[259] Consequently, in the *Policy Statement*, the Commission withdrew its Notice of Proposed Rulemaking issued February 12, 2004, that proposed: (1) to amend Commission regulations to require interstate natural gas pipelines to follow standardized procedures for determining the creditworthiness of their shippers; and, (2) "to incorporate by reference ten [procedural] creditworthiness standards promulgated by the North American Energy Standards Board['s Wholesale Gas Quadrant (NAESB WGQ)]."[260]

However, prior to the issuance of the *Policy Statement*, the Commission, on May 9, 2005, issued Order No. 587-S in which it "incorporat[ed] by reference the most recent version, Version 1.7, of the consensus standards promulgated by the [NAESB's WGQ]."[261] Furthermore, in the *Policy Statement*, the Commission found the WGQ Executive Committee's proposal, which recommended a uniform set of financial documents and related information that shippers should provide pipelines, to be a reasonable compilation of data sufficient to evaluate shipper credit.[262]

Further, most of the *Policy Statement's* guidance follows various creditworthiness determinations that were enunciated in prior Commission orders. For example, with respect to establishing a uniform set of criteria for

255. *Id.* at P 1.

256. *Policy Statement*, *supra* note 254, at P 6.

257. *Id.* at p. 31,670-671.

258. *Policy Statement*, *supra* note 254, at p. 31,670.

259. *Id.* at PP 4-6.

260. Notice of Proposed Rulemaking, *Creditworthiness Standards for Interstate Natural Gas Pipelines*, F.E.R.C. STATS. & REGS. ¶ 32,573, 69 Fed. Reg. 8587 (2004); *see also* Report of Natural Gas Regulation Committee, 25 ENERGY L.J. 217-45 (2004).

261. Order No. 587-S, *Standards for Business Practices of Interstate Natural Gas Pipelines*, F.E.R.C. STATS & REGS. ¶ 31,179, 70 Fed. Reg. 28,204 (2005). Among other things, Version 1.7 contains the ten procedural standards concerning creditworthiness that the Commission proposed to adopt in the 2004 NOPR.

262. *Policy Statement*, *supra* note 254, at PP 8-10. The WGQ Executive Committee considered this standard, but it did not adopt it. Also, the Commission stated that pipelines may, in appropriate cases, require additional information, but they should be able to justify why the additional data is necessary. *Id.*

determining creditworthiness, the Commission declined to adopt uniform standards, but it continued its policy that pipelines must establish and use objective criteria for determining creditworthiness.[263] Under the *Policy Statement*, a pipeline will be expected "to provide 30 days notice to the Commission prior to terminat[ion] of service."[264] However, the Commission will permit pipelines to suspend service on a shorter notice because this "allows the pipeline to protect itself against potential losses arising from the continuation of service to a non-creditworthy shipper."[265] In instances where the pipeline opts to suspend the service required under the shipper's contract, the Commission states that it will not permit pipelines to impose reservation charges during the period of suspension.[266]

Pursuant to the *Policy Statement*, the Commission concluded that it would continue to adhere to its traditional policy of requiring no more than the equivalent of three months worth of reservation charges for shippers using existing facilities.[267] The Commission, however, stated that it needs to consider on a case-by-case basis any pipeline proposal to take into account a shipper's credit status in determining whether more than three months of collateral should be required when shippers are bidding for available capacity on the pipeline's existing system.[268] Notably, on March 9, 2006, the U.S. Court of Appeals for the District of Columbia Circuit issued an order granting the Commission's *sua sponte* motion, which requested that three appeals be remanded to the Commission for reconsideration of three of its orders concerning whether North Baja Pipeline, LLC (North Baja) and PG&E Transmission, Northwest Corporation (GTN)[269] should be permitted to collect twelve months of collateral from non-creditworthy shippers on existing facilities as opposed to following the Commission's general policy allowing for the collection of three months collateral.[270] The Commission directed North Baja and GTN to file a brief to

263. *Policy Statement*, *supra* note 254, at PP 8-10. The Commission cited its decisions in *Tennessee Gas Pipeline Co.*, 102 F.E.R.C. ¶ 61,075 at P 41 (2003), *order on reh'g*, 103 F.E.R.C. ¶ 61,275 at PP 40-41 (2003); and, *PG&E Gas Transmission, Northwest Corp.*, 103 F.E.R.C. ¶ 61,137 at P 67 (2003).

264. *Policy Statement*, *supra* note 254, at P 23. Citing to its regulations, (18 C.F.R. § 154.602 (2003)) the Commission noted that termination of service is an abandonment of service. Moreover, the Commission reasoned that the 30-day notice period ensures that it has an opportunity to determine if termination is in the public convenience and necessity. *Policy Statement*, *supra* note 254, at P23 (citing, *Northern Nat. Gas Co.*, 103 F.E.R.C. ¶ 61,276 at P 51 (2003)).

265. *Policy Statement*, *supra* note 254, at P 24.

266. *Id.* In *Tennessee Gas Pipeline Co. v. FERC*, 400 F.3d 23 (D.C. Cir. 2005), the court upheld the Commission's policy of not permitting a pipeline to recover full reservation charges during suspension. However, the court opined that the Commission's regulations do not appear to foreclose an argument to permit a lesser reservation charge during a period of suspension, but the Court declined to make such a determination since the issue was not before it. *Id.* at 28.

267. *Policy Statement*, *supra* note 254, at P 14. With respect to construction projects, the Commission adhered to its policy of permitting larger collateral requirements and requiring that issues related to collateral requirements be determined in the precedent agreements at the certificate stage rather than included in the pipeline's tariff. Similarly, the Commission followed its established policy of allowing pipelines to require up to the full cost of a lateral line construction since the projects are for the benefit of one or a few shippers. *Id.*

268. *Policy Statement*, *supra* note 254, at P 15.

269. PG&E Gas Transmission changed its name to Gas Transmission Northwest Corporation (GTN).

270. *North Baja Pipeline, LLC*, 115 F.E.R.C. ¶ 61,141 at P 1 (2006). In 2002 and 2003, the Commission issued orders in three separate proceedings, wherein the Commission limited North Baja and GTN to

address, based on the specific facts and circumstances of the two pipelines, why the Commission should approve a twelve-month collateral requirement for existing non-creditworthy shippers instead of the Commission's general policy of three months of collateral.[271]

VII. DISCOUNTING AND NEGOTIATED RATES

In 2005 and 2006, the Commission issued two policy decisions that essentially affirmed the longstanding commercial practices of pipelines with respect to discounting and negotiated rates.

A. Policy for Selective Discounting By Natural Gas Pipelines, Docket No. RM05-2

On May 31, 2005, the Commission issued its *Order Reaffirming Discount Policy and Terminating Rulemaking Proceeding*[272] in its inquiry begun in 2004 over the practice of selective discounting by pipelines. The inquiry, initiated in part to respond to an earlier petition from the Illinois Municipal Gas Agency (IMGA), sought comments as to whether the practice of selective discounting of services, in place since open-access transportation began in 1985, should be terminated or sharply limited. In the May 31, 2005, order, the Commission determined that existing practices, whereby pipelines are free to negotiate such discounts as are needed by the market, on an individual customer basis, should be allowed to continue. The Commission summarized its determination as follows:

> after reviewing the comments, the Commission finds that its current policy on selective discounting is an integral and essential part of the Commission's policies furthering the goal of developing a competitive national natural gas transportation market. The Commission further finds that the selective discounting policy provides for safeguards to protect captive customers. If there are circumstances on a particular pipeline that may warrant special consideration or additional protections for captive customers, those issues can be considered in individual cases. This order is in the public interest because it promotes a competitive natural gas market and also protects the interests of captive customers.[273]

Chairman Wood concurred, but expressed a preference to have required more information from pipelines as to the reason for a discount. Commissioner Kelly dissented in part over the same issue, advocating a requirement that

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recovering three months of collateral from non-creditworthy existing shippers instead of the twelve months of collateral that the pipelines proposed. *North Baja Pipeline, LLC*, 102 F.E.R.C. ¶ 61,239 (2003), *order on reh'g and clarification*, 105 F.E.R.C. ¶ 61,374 (2003); *PG&E Gas Transmission, Northwest Corp.*, 102 F.E.R.C. ¶ 61,289 (2003), *order on reh'g and clarification*, 104 F.E.R.C. ¶ 61,026 (2003); *PG&E Gas Transmission, Northwest Corp.*, 101 F.E.R.C. ¶ 61,280 (2002), *order on technical conference and reh'g*, 103 F.E.R.C. ¶ 61,137 (2002), *order on compliance and reh'g*, 105 F.E.R.C. ¶ 61,382 (2003). North Baja and GTN appealed the Commission orders and the three appeals were consolidated in *Gas Transmission Northwest Corp. v. FERC*, No. 03-1257 (D.C. Cir. filed Aug. 29, 2003).

271. *North Baja Pipeline, LLC*, 115 F.E.R.C. ¶ 61,141 at PP 9-14 (2006). North Baja and GTN were required to file the briefs within 30 days of the date of the Commission's order, which is by June 2, 2006, and 30 days thereafter, the other parties may file comments. *Id.* at P 14.

272. 111 F.E.R.C. ¶ 61,309 (2005).

273. *Id.* at P 2.

pipelines post a "check-off" list of reasons for a discount, identifying which reason applied to each discount.

B. Natural Gas Pipeline Negotiated Rate Policies and Practice, Docket No. PL06-2

On January 19, 2006, the Commission issued its *Order on Rehearing and Clarification*[274] regarding the acceptability of negotiated rates based upon commodity price index differentials. In a 2003 *Statement of Policy*,[275] such pricing formulas had been prohibited, although later flexibility was accorded to index-based contracts that were limited by recourse-rate revenue levels.

The Commission's fundamental concern had been that index-based contracts created an incentive for a pipeline to manipulate capacity availability, in order to affect basis differentials. In reversing this prior policy, the Commission said:

> However, in the Commission's view, the ability of pipelines to manipulate the gas commodity market is tempered by several factors. First, Part 284 of the Commission's regulations and its policies provide that pipelines must sell capacity to maximum rate bidders. Therefore, pipelines may not hoard desired capacity in an attempt to widen basis differential without violating the Commission's existing regulations. Second, pipelines must file all negotiated rate agreements with the Commission for approval. Those filing negotiated rate contracts are noticed for comments giving all interested parties an opportunity to raise whatever concerns they have with the agreement. Moreover, the Commission has access to information regarding available pipeline capacity and daily gas basis differentials. This allows it to monitor the transactions to determine if the pipeline is withholding capacity in order to increase the gas commodity basis differential. Moreover, subsequent to the modification of the negotiated rate policy statement, Congress enacted new legislation designed to prohibit manipulation of the gas transportation markets.[276]

VIII. MARKET-BASED RATES FOR STORAGE

On June 19, 2006, the Commission issued Order No. 678, the *Final Rule on Rate Regulation of Certain Natural Gas Storage Facilities*. This Final Rule followed on a Notice of Proposed Rulemaking (NOPR) issued in December 2005 in Docket No. RM05-23. There are two major components of the rule: (1) a broadening of the Commission's existing test for market-based storage rates, to take into account relatively more non-storage alternatives; and, (2) implementation of new section 1(f) of the NGA, enacted as section 312 of the EPAct 2005, to allow market-based rates in certain situations even if market power may be present. The Commission's press release summarized the final rule as follows:

> The final rule provides two approaches for developers of natural gas storage facilities to seek authority to charge market-based rates.

274. 114 F.E.R.C. ¶ 61,042 (2006).

275. *Natural Gas Pipeline Negotiated Rate Policies and Practices*, 104 F.E.R.C. ¶ 61,134 (2003), *order on reh'g*, 114 F.E.R.C. ¶ 61,042 (2006).

276. 114 F.E.R.C. ¶ 61,042 at P 10.

The first approach includes a more expansive definition of the relevant product market for storage that would include, to the extent they can be shown to be good substitutes for storage, available pipeline capacity, local gas production and liquefied natural gas terminals. "This modification to our market-power analysis better reflects the competitive alternatives to storage and is supported by changes in the natural gas markets that have occurred since the mid 1990s," the Commission noted.

Currently, the Commission follows the analytical framework of its 1996 Alternative Rate Policy Statement, which established procedures to allow applicants to demonstrate they lack significant market power in a relevant market.

The Commission said its current approach to analyzing market power may be a disincentive to developing new storage infrastructure since it does not consider that non-storage products and services in a properly defined geographic market may provide alternatives to storage services and thus mitigate storage providers' potential ability to exercise market power.

A second approach, which implements section 312 of the Energy Policy Act, would allow an applicant to request authority to charge "market-based rates even if a lack of market power has not been demonstrated, in circumstances where market-based rates are in the public interest and necessary to encourage the construction of storage capacity in the area needing storage service and that customers are adequately protected," the Commission said.[277]

277. Press Release, FERC, Commission Finalizes Rules on Market-Based Rates for Interstate Natural Gas Storage Facilities (June 15, 2006), *available at* http://ferc.gov/press-room/press-releases/2006/2006-2/06-15-06-C-2.asp.

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William E. Rice
Jason M. Ryan
D. Billye Sanders
Laura M. Schepis
Steven M. Sherman
Andrew K. Soto
Regina Y. Speed-Bost
Sarah E. Tomalty
Robert A. Weishaar, Jr.
Anita R. Wilson
Joel A. Youngblood