IX. Gas

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A. Introduction

This report reviews regulatory developments in the interstate natural gas industry during the period March 2012 through February 2013 and provides an overview of the major federal orders and initiatives, including rulemaking by the Federal Energy Regulatory Commission (FERC). Pertinent appellate decisions are highlighted as well.

B. Significant Rulemaking Orders

1. Order No. 587-V, Final Order, Standards for Business Practices of Interstate Natural Gas Pipelines

On July 19, 2012, the Commission issued Order No. 587-V, the Final Rule in *Standards for Business Practices of Interstate Natural Gas Pipelines*.[1] In Order

1. Standards for Business Practices of Interstate Natural Gas Pipelines, 140 FERC ¶ 61,036 (2012), 77 Fed. Reg. 43,711 (July 26, 2012).

No. 587-V, the Commission incorporated by reference the North American Energy Standards Board's (NAESB) Version 2.0, which includes new and modified standards to support gas-electric interdependency by further defining the roles and responsibilities of each participant. Version 2.0 provides more details on what is included in various notices through the creation of fifteen new notice types, enabling public utilities to more easily identify relevant pipeline system conditions.[2] The new notice types are used in the pipelines' informational postings on their websites to notify shippers and other interested parties of intraday bumps, operational flow orders (OFOs), and other critical information by e-mail or other electronic methods. The increased granularity of information will allow shippers and other interested parties to filter notices more effectively and to focus on specific types of notices while ignoring less relevant notices. The revised standards also specify information that the pipelines will post concerning the installation of waste heat recovery systems to facilitate the Commission's objectives of promoting efficient design and operation of gas facilities.

The new standards clarify and revise requirements for the reporting of available capacity by the pipeline and scheduled quantities.[3] However, Order No. 587-V does not resolve the issue of whether "Operating Capacity," as defined by NAESB Standards, and "Design Capacity," which a pipeline must report per the Commission's regulations in 18 C.F.R. § 284.13(d), are equivalent terms. The Commission requested that the industry resolve this matter through the NAESB process.[4] The new and revised standards are intended to enhance electric and gas industry coordination by providing electric plant operators with more information on whether hourly flow deviation requests can be honored; to clarify critical, noncritical, and planned service outage notices of pipelines; and to expand the parties to whom pipelines must give notice of operational flow orders and other critical notices.[5]

Order No. 587-V clarified the Commission's policy on granting waivers and extensions of time for pipelines to adopt new NAESB standards and on the renewal/extension of prior waivers.[6]

2. Notice of Proposed Rulemaking, Revisions to Procedural Regulations Governing Transportation by Intrastate Pipelines, Docket No. RM12-17-000

On October 18, 2012, the Commission issued its Notice of Proposed Rulemaking, *Revisions to Procedural Regulations Governing Transportation by*

2. Since 1996, the Commission has in a series of orders adopted regulations to standardize business practices and communications methodologies of pipelines to create an integrated pipeline grid. These standards are first promulgated by the North American Energy Standards Board (NAESB), which is a consensus standards organization open to all members of the industry—pipelines, producers, distribution companies, gas users, and services, e.g., marketers and computer service providers.

3. 140 FERC ¶ 61,036, at PP 17–20.

4. *Id.* at PP 29–30.

5. *Id.* at PP 21–26.

6. *Id.* at PP 38–41.

Intrastate Pipelines,[7] which proposed revisions to the regulations governing the filing obligations of companies providing interstate transportation subject to § 284.224 of the Commission's regulations, which govern certain transportation offered under § 311 of the Natural Gas Policy Act of 1978 (NGPA) and under Order 63 certificates granted pursuant to § 1(c) of the Natural Gas Act (NGA) (Hinshaw pipelines) (collectively, § 311 transporters).[8] The Commission outlined the current regulatory context for § 311 transportation, including the several options, or rate elections under different ratemaking methods (essentially permitting the use of approved state-determined rates or rates approved by the Commission), available to § 311 transporters, which require the filing of rates and terms and conditions (Statement of Operating Conditions) subject to Commission review.[9] Currently, the Commission requires periodic review of the rates filed by § 311 transporters, although in Order No. 735,[10] the Commission lengthened the previous triennial re-filing obligation to five years.[11]

The Commission proposes to streamline its regulations and eliminate unnecessary burdens on regulated companies. The principal proposed change (in proposed 18 C.F.R. § 284.123(g)) would be to add an optional procedure under which § 311 transporters could seek approval of either rates or operating conditions without the need for a Commission order. If the filing is not protested, or if any protests were resolved within a reconciliation period, no Commission order would be needed.[12]

The Commission supported the proposed rule as being appropriate, given the small size and small number of shippers of many § 311 transporters, the fact that many such transporters transport most service at substantial discounts, and the lack of protests for most rate filings. In a manner similar to the protest procedures for blanket certificate filings by interstate pipelines under 18 C.F.R. § 157.205,[13] unprotested § 311 transporter filings would be subject to a published notice, which would then have a (potentially) sixty-day notice period. If any protests were filed, a thirty-day reconciliation period would follow to permit possible settlement. If the filing were not protested, it would become effective. If the filing was protested and the protest still unresolved after the

7. Revisions to Procedural Regulations Governing Transportation by Intrastate Pipelines, 77 Fed. Reg. 66,568 (Nov. 6, 2012), FERC Stats. & Regs., Proposed Regs. ¶ 32,695 (2012) (NOPR).

8. Despite the differences in the jurisdictional basis for the regulation of NGPA and NGA § 1(c) transportation, there is significant overlap between the regulations applicable to the two types of companies. For purposes of this discussion, both will be referenced in this summary as "§ 311 transporters."

9. NOPR at PP 2–6.

10. Contract Reporting Requirements of Intrastate Natural Gas Companies, Order No. 735, 75 Fed. Reg. 29,404 (May 26, 2010), FERC Stats. & Regs. ¶ 31,310, at P 96 (2010), *order on reh'g*, Order No. 735-A, 75 Fed. Reg. 80,685 (Dec. 23, 2010), FERC Stats. & Regs. ¶ 31,318 (2010).

11. NOPR at P 7.

12. *Id.* at P 8.

13. *Id.* at P 10.

reconciliation period, then the Commission would establish procedures to resolve the issues.[14] Ex parte rules would continue to apply,[15] and there would be delegated authority to reject incomplete filings, without prejudice to resubmission, within seven days of the filing.[16] Additionally, protests could be withdrawn; if withdrawn within the appropriate timeframe, the result would be deemed approval of the filing as an unprotested filing.[17] The filing entity could also withdraw the filing prior to Commission action, subject to the obligation to refund any increased rates collected under the filing,[18] and any filing could be withdrawn prior to approval, subject to the refund obligation and shipper comment.[19] Companies successfully filing rates under the "no Commission action" option would still be required to file either revised rates (intrastate pipelines) or a cost/revenue study (Hinshaw pipelines) within five years of the date that the entity filed for rate approval under this optional approach.[20]

3. Notice of Inquiry, Enhanced Natural Gas Market Transparency, Docket No. RM13-1-000 (November 15, 2012)

On November 15, 2012, the Commission issued its Notice of Inquiry in *Enhanced Natural Gas Market Transparency*,[21] seeking comments regarding what, if any, regulatory changes should be made pursuant to NGA § 23, as enacted in the Energy Policy Act of 2005 (EPAct 2005).[22] In accordance with the authority to obtain information about the availability and prices of natural gas sold at wholesale and in interstate commerce from "any market participant," and in light of the prohibition in NGA § 4A against deceptive and manipulative devices and practices,[23] the Commission announced that it is considering requiring all market participants that sell wholesale physical delivery of natural gas in interstate commerce to report on a quarterly basis every natural gas transaction within the Commission's NGA jurisdiction involving physical delivery for the next day or within the next month.[24] Among other steps,[25] the Commission reviewed the statutory basis for its transparency regulations in the EPAct 2005; the NGA; its prior regulations implementing transparency obligations in Order

14. *Id.* at PP 9, 11–13.
15. *Id.* at P 14.
16. *Id.* at P 15.
17. *Id.* at P 16.
18. *Id.* at P 17.
19. *Id.* at P 20.
20. *Id.* at P 18.
21. Enhanced Natural Gas Market Transparency, 141 FERC ¶ 61,124 (2012) (Notice).
22. Energy Policy Act of 2005, Pub. L. No. 109-5, § 316, 119 Stat. 594 (EPAct 2005) (codified as 15 U.S.C. § 717t-2).
23. Notice at P 2.
24. *Id.* at P 9.
25. Notice at PP 4–9.

Nos. 704, 720, and 720-A;[26] and its regulations implementing anti-manipulation requirements in Order No. 670.[27]

The Commission stated that Order Nos. 704 and 720 commenced its efforts to facilitate price transparency, but that it has identified additional information that may be necessary that would permit the Commission to detect and ultimately deter market manipulation.[28] After noting the scope of available data, the Commission stated that the currently available data do not provide "full market visibility or transparency," chiefly because the data are aggregated and not transaction-specific, citing in particular the information lacking in off-exchange transactions of physical gas, the limitation in detail provided by Form 552, and the aggregated nature of data available regarding scheduled natural gas pipeline flows.[29]

To address this need, the Commission stated that it is considering requiring all sellers of wholesale physical natural gas in interstate commerce to provide in a standardized electronic format quarterly reports on every natural gas transaction within the Commission's NGA jurisdiction that involves next-day delivery or delivery in the next month. In particular, the Commission is considering requiring market participants to report the following data elements for all such transactions in a standardized, electronic format on a quarterly basis: name; address and contact information of the trading company; name and location of its holding company; product traded, i.e., next-day-delivery natural gas and next-month-delivery natural gas; trade execution method, i.e., exchange or off-exchange, and name of exchange or broker, and settlement type, e.g., fixed or index-priced; volume (in MMBtu) of natural gas traded; location (hub); price, date, and time of the transaction; name of the counterparty; and the names of the index publishers to which each transaction was reported.[30] Further, the Commission stated that it is considering making all of the data collected publicly available one month after they are reported to the Commission, in compliance with the requirement of NGA § 23's requirement of timely and public dissemination of information about the availability and prices of natural gas.[31] The Commission provided a series of specific questions as to the proposed reporting obligations, ranging from the data elements to the quarterly reporting timeframe, and whether to expand the requirement to other transactions such as intra-day and non-next-day

26. Transparency Provisions of Section 23 of the Natural Gas Act, Order No. 704, FERC Stats. & Regs. ¶ 31,260 (2007), *order on reh'g*, Order No. 704-A, 73 Fed. Reg. 55,726 (Sept. 26, 2008), FERC Stats. & Regs. ¶ 31,275 (2008), *order dismissing reh'g & clarification*, Order No. 704-B, 125 FERC ¶ 61,302 (2008) (Order No. 704); Pipeline Posting Requirements Under Section 23 of the Natural Gas Act, Order No. 720, 73 Fed. Reg. 73,494 (Dec. 2, 2008), FERC Stats. & Regs. ¶ 31,283, at P 3 (2008), *order on reh'g*, Order No. 720-A, 130 FERC ¶ 61,040 (2010) (Order No. 720).

27. Prohibition of Energy Market Manipulation, Order No. 670, FERC Stats. & Regs. ¶ 31,202 (2006).

28. *Id.* at P 10.

29. *Id.* at P 11.

30. *Id.* at P 13.

31. *Id.* at P 14.

deliveries.[32] The Commission posed other questions related to (1) the scope and consequences of the proposed public dissemination, and whether it would be necessary to mask, limit, or aggregate publicly disclosed data;[33] (2) the scope of transactions subject to the reporting, e.g., whether to include sales not subject to its NGA jurisdiction, and how to minimize the difficulty of determining whether to report and what the commercial consequences would be;[34] and (3) the extent and nature of the burden on market participants, including whether to discontinue the Form 552 or include a de minimis limit.[35]

4. Order Directing Further Conferences and Reports, Coordination Between Natural Gas and Electricity Markets, Docket No. AD12-12-000

On November 15, 2012, the Commission issued its Order Directing Further Conferences and Reports in *Coordination Between Natural Gas and Electricity Markets*.[36] The Conference Order did not undertake any specific new regulations or policies but represented a substantial increase in the Commission's efforts to gather information about and further address the issues arising from the increased need for coordination between the natural gas pipeline market and the electric generation market. Concurrently with the issuance of the Conference Order, the Commission made available to the public the Staff Report on Gas-Electric Coordination Technical Conferences (Docket No. AD12-12-000), November 15, 2012 (Staff Report).

In the Conference Order, the Commission stated that the August 2012 conferences showed that, although gas/electric coordination issues varied by region, efforts were underway to address them. The Commission also noted that general concerns existed across the industry, in particular "the respective ability of each industry to share information in furtherance of enhancing gas-electric coordination consistent with the Commission's regulations on Standards of Conduct and statutory restrictions on undue discrimination and preference," as well as scheduling "discontinuities" between the industries, including the "no bump" rule and the capacity release restrictions.[37] In addition, the Commission noted that the Staff Report discussed other significant issues, such as whether the electric market provides incentives adequate to "ensure gas-fired generator performance or otherwise signal the need for pipeline infrastructure to meet growing needs."[38]

As a consequence of these conferences and the Staff Report, the Commission concluded that further "targeted technical conferences" were needed, as well as conferences to obtain input from the regional transmission organizations (RTOs) and independent system operators (ISOs). The latter conferences were scheduled

32. *Id.* at P 16.
33. *Id.* at P 18.
34. *Id.* at P 19.
35. *Id.* at P 20.
36. Coordination Between Natural Gas and Electricity Markets, 141 FERC ¶ 61,125 (2012) (Conference Order).
37. *Id.* at P 3.
38. *Id.* at P 3, n.2.

for May 16, 2013, and October 17, 2013, to obtain further information on the industry's experiences in the different seasons.[39] The Commission also directed its staff to establish a conference to address specific potential changes and/or guidance with respect to the Standards of Conduct and coordination issues.[40]

The Commission also provided some guidance in the Conference Order regarding the purpose of the Standards of Conduct, emphasizing the "emergency" exception.[41] As to concerns about undue preferences arising from the sharing of information between the industries, the Commission expressed the hope that additional guidance on the nature and limitations of use of such data exchanges would alleviate the problem.[42] The Commission also highlighted the avenues by which industry participants could gain advice and guidance from the Commission with respect to particular data exchanges.[43] Concerns about potentially changing scheduling policies were to be addressed at a separate conference.[44] The Commission directed Commission staff to report on the industries' natural gas and electric coordination issues at least once each quarter in 2013 and 2014.

C. Significant Judicial Decisions

1. *Coalition for Responsible Growth and Resource Conservation v. Federal Energy Regulatory Commission*, 2012 U.S. App. LEXIS 11847, issued June 12, 2012 (summary order)

On June 12, 2012, the U.S. Court of Appeals for the Second Circuit issued a Summary Order, *Coalition for Responsible Growth v. Federal Energy Regulatory Commission*.[45] Although a summary order is of restricted precedential use under the court's rules, the Summary Order is of interest in light of its subject matter relating to shale. The case involved a petition for review by environmental interests of a Commission order granting a certificate to a pipeline company to build a thirty-nine-mile-long pipeline project through certain northern Pennsylvania counties.[46] The petitioners contended that the Commission's consideration of the impact of the project on the development of the Marcellus Shale and its attendant environmental effects was not adequate.[47] The court found that the Commission's environmental analysis was adequate, that it was correct in concluding that a sufficient causal nexus did not exist between the project and the development of the Marcellus Shale to warrant a more in-depth analysis, and that the specific environmental issues addressed by the Commission were proper with adequate conditions.[48]

39. *Id.* at PP 4, 12.
40. *Id.* at P 5.
41. *Id.* at P 7.
42. *Id.* at P 8.
43. *Id.* at P 9.
44. *Id.* at PP 10, 11.
45. 2012 U.S. App. LEXIS 11847 (June 12, 2012) (Order).
46. *Id.*, *slip op.* at 1.
47. *Id.* at 4.
48. *Id.*

2. *Northern Natural Gas Company v. Federal Energy Regulatory Commission*, 700 F.3d 11 (D.C. Cir. 2012)

On November 27, 2012, the D.C. Circuit issued a decision in *Northern Natural Gas Company v. Federal Energy Regulatory Commission*,[49] in which it denied petitions for review of the Commission's orders in two rate orders that addressed the scope of a pipeline's authority to enter into market-based contracts for storage service originally authorized under § 4(f) of the NGA.[50] Under § 4(f), FERC may authorize under cetain conditions for market-based rates for new storage capacity without finding that the company offering the storage service lacked significant market power. Specifically, the Commission needed to find that the market-based rates are "necessary to encourage the construction of the storage capacity in the area needing storage service."[51] In the proceedings below, the applicant pipeline had obtained authority to construct new storage capacity and charge market-based rates for storage service, but the authority to charge market-based rates was expressly limited to the initial shippers that submitted winning bids for the new storage capacity in an "open season" auction held to allocate capacity in newly constructed facilities.[52]

In 2010, the pipeline filed to extend the market-based rate authority to include contracts resulting from the expiration of the initial contracts or other causes (turn-back of capacity, bankruptcy). The Commission rejected the proposal to make market-based authority applicable to contracts for capacity becoming available following the expiration of the initial contracts, finding that the capacity had at that point already been constructed and hence did not meet the requirement of § 4(f) that such market-based rate authority must be needed to encourage the construction of the storage capacity.[53] The Commission did approve the application of market-based rates for the resale of capacity following bankruptcy or turn-back occurring within the twenty-year initial term of the original service agreements.[54] The pipeline then sought judicial review at the D.C. Circuit.

The court found the Commission's interpretation of § 4(f) to be reasonable and in fact "fully consistent with the obvious meaning of the statute."[55] The court noted that the Commission had emphasized the role of the market-based rate authority for encouraging new capacity even in its generic rulemaking issued prior to the Certificate Order and further found that the goal of encouraging new capacity could not be met once the capacity was constructed.[56] The pipeline had not sought judicial review of the favorable aspect of the 2010 Order, thereby allowing market-based rate authority to apply to certain successor contracts

49. 700 F.3d 11 (D.C. Cir. 2012).
50. N. Natural Gas Co., 133 FERC ¶ 61,210 (2010) (2010 Order), *reh'g denied*, 135 FERC ¶ 61,085 (2011) (2011 Rehearing Order).
51. *N. Natural Gas Co.*, 700 F.3d at 13.
52. *Id.*
53. *N. Natural Gas Co.*, 133 FERC ¶ 61,210 at P 11.
54. *Id.* at P 12.
55. *N. Natural*, 700 F.3d at 14.
56. *Id.*

occurring within the twenty-year term of the initial contracts; however, the court addressed the issue and observed that the distinction could be justified on the grounds that the permitted market-based contracts would “fill in a gap” in the originally authorized market-based rate contracts.[57] The court also rejected the pipeline’s argument that additional investment might be required. It noted that the risk of such investment could have been addressed by the pipeline seeking a more expansive initial authorization, e.g., for successor contracts, in its original request, and that additional investment might, upon application to the Commission, be found to fall within the scope of § 4(f) for market-based rates.[58]

The court also considered, but rejected, a further argument by the pipeline that for a certain expansion of the storage facilities (Iowa expansion), the rule announced in the 2010 case should only be applied prospectively to the contracts because in a 2007 order regarding the Iowa expansion contracts, the Commission had suggested (in what the court characterized as dicta) that market-based rates might be available for contracts succeeding the original twenty-year contracts.[59] Although the court agreed that the 2007 Order suggested that market-based rates were possible for successor contracts to the Iowa expansion capacity, it declined to “exempt” that capacity from the ruling by the Commission in the 2010 Order.[60] The Commission found no evidence indicating that the pipeline had actually relied on the 2007 Order in deciding whether to proceed with the Iowa expansion. It noted that even though the construction was subsequent to the 2007 Order, there was no showing that the construction was contingent on this holding. Further, the court concluded, any such reliance would not have been reasonable because the 2007 Order does not suggest that market-based rates would necessarily be available. Rather, the Order merely suggested, in dicta, that such rates may apply beyond the primary term of the agreement and did not pass judgment on that issue.[61] Hence, the court found that the dicta, even if somewhat misleading, did not prevent the Commission from applying the standard in the 2010 Order to the Iowa expansion.[62]

D. Enforcement Matters

On November 30, 2012, the Commission issued an order approving a stipulation and consent agreement between the Office of Enforcement and Alliance Pipeline, L.P., under which Alliance agreed to pay a $500,000 civil penalty.[63]

57. *Id.*
58. *Id.* at 15.
59. *Id.* (citing N. Natural Gas Co., 120 FERC ¶ 61,233 (2007) (2007 Order)).
60. *Id.* at 15–16.
61. *Id.* at 16.
62. *Id.*
63. Alliance Pipeline L.P., 141 FERC ¶ 61,182 (2012).

Alliance admitted that its executives and those at its parent company had discussed the purchase of capacity by the parent at a loss in order to maintain the value of capacity.[64] Days before an auction for capacity, an Alliance employee had provided a summary to the parent company that concluded that additional capacity was available at upstream receipt points. Alliance posted the capacity for auction but did not clearly identify to the market participants the change in amount of capacity available at such upstream points. Alliance's parent company created a new affiliate that was awarded the capacity even though the affiliate had not appeared on Alliance's approved bidder list, as required by Alliance's auction rule.[65] Enforcement determined that Alliance had (1) violated the "no conduit" rule of the Commission's Standards of Conduct by disclosing to marketing function employees of an affiliate, through communications with the owners, nonpublic transmission function information about availability of additional capacity at upstream points; (2) violated the "transparency rule" by failing to provide the information to other market participants at the same time it informed its owners; and (3) violated its tariff by accepting bids of its affiliate that was not on the approved bidder list.

E. Reservation Charge Crediting

1. Texas Eastern Transmission, LP (RP12-318)

On September 20, 2012, the Commission issued an order[66] on rehearing its February 16, 2012, order,[67] which directed Texas Eastern Transmission to revise its tariff provisions governing revenue crediting, or explain why it should not be required to so do.

The rehearing order found that contrary to Texas Eastern's claim—that the Commission had improperly initiated this § 5 proceeding based solely on a general comparison of its tariff provisions to the nonbinding policy set out in *Natural Gas Supply Ass'n* (*NGSA*)[68]—the Commission did not rely on or cite *NGSA*. Rather, the Commission had found that each provision conflicted with binding precedents established in adjudications concerning the reservation charge crediting provisions of individual pipelines. The major elements of the Commission's policy had been affirmed by the D.C. circuit in *North Baja v. FERC*.[69] The rehearing order concluded that the Commission had

64. The concern raised was that customers with options to renew contracts later in the year would view unsubscribed capacity as an indication of lower value.

65. A complaint regarding Alliance's filing of the negotiated rate contract with its newly created affiliate precipitated the Commission investigation.

66. Tex. E. Transmission, LP, 140 FERC ¶ 61,216 (2012).

67. Tex. E. Transmission, LP, 138 FERC ¶ 61,126 (2012).

68. 135 FERC ¶ 61,055, *order on reh'g*, 137 FERC ¶ 61,050 (2011). Texas Eastern asserted that the Commission therefore had not met its initial burden of producing evidence that the existing tariff provisions were unjust and unreasonable.

69. 483 F.3d 819 (D.C. Cir. 2007).

made a prima facie showing that Texas Eastern's provisions are unjust and unreasonable because they are inconsistent with the policy established in these cases.

Texas Eastern had challenged the Commission policy on full crediting for routine maintenance, claiming that rigid application of the policy would undermine protections in place on its system since Order No. 636 restructuring (early notice of maintenance outage, and maintenance only scheduled during off-peak season) and would create dangerous incentives for Texas Eastern to minimize maintenance and safety outages. Texas Eastern also argued that the Commission did not certify capacity that would allow the pipeline to provide firm service up to design capacity every day of the year, which would require inefficient and redundant facilities. Further, Texas Eastern asserted that, contrary to the Commission's findings, scheduled maintenance outages are not the result of "mismanagement" but rather the direct result of efforts to enhance reliability and comply with safety regulations.

In denying rehearing, the Commission stated that it has consistently treated such outages as non–force majeure events, even where the pipeline has little or no excess capacity and has required full revenue charge crediting in order to provide an incentive for the pipeline to minimize the interruption. As for cost issues, the Commission found that each pipeline must make determinations as to the most cost-effect method to minimize interruptions and may recover the prudently incurred costs in their rates. As for Texas Eastern's claim that its current tariff provision, i.e., providing for full crediting for maintenance during peak periods, is a "cost sharing mechanism" that has worked without customer complaint for a long period, the Commission disagreed, finding that cost-sharing mechanisms for scheduled maintenance are inherently unjust and unreasonable because they provide insufficient incentive to minimize disruption. The Commission also noted that it has required pipelines to modify their tariffs without regard to past history of disruption or complaint.

With regard to Texas Eastern's exemption from crediting for performing repair or maintenance to comply with regulatory requirements, the Commission found the provision unjust and unreasonable because it imposes on shippers the entire risk of any service interruption, which can occur at any time and with no crediting at all. Citing *North Baja*, the Commission reiterated its position that government-required testing and maintenance are part of a pipeline's duties under its certificate and are not force majeure events. Pipelines have some degree of control over when they conduct these activities, and the need to conduct such activities cannot be considered "unexpected" in any event. The Commission noted that Texas Eastern may propose to include in the definition of force majeure outages to comply with government requirements that are "both outside the pipeline's control and unexpected." Likewise, the Commission found that Texas Eastern's exemption from crediting for failure to deliver during OFO periods is unjust because it does not comport with Commission policy. However, if the OFO were the result of a force majeure event outside of the pipeline's control, then only partial crediting would be required.

2. Northern Natural Gas Co. (RP11-2061)

On December 20, 2012, the Commission issued an order that denied Northern Natural Gas Co.'s request for rehearing and addressed a Northern Natural compliance filing, both concerning a reservation charge crediting provision.[70] The Commission affirmed its holding that a prior rate settlement did not preclude alteration of Northern Natural's reservation charge crediting provision until Northern Natural filed a § 4 rate case. As to Northern Natural's claim that reservation charge crediting provisions can only be modified in a general § 4 rate case because the provisions may affect the ability to recover cost, the Commission upheld its prior holding: the pipeline could either make a § 4 filing to recover such costs or, alternatively, seek to recover compliance costs within its pending § 5 proceeding by providing evidence of the number of non-force majeure outages and dollar credits it had to give and other information to determine whether existing rates are insufficient to recover additional cost of compliance (i.e., filing of a cost and revenue study similar to that required in Commission-initiated § 5 rate investigations).

The Commission affirmed its holding that Northern Natural must provide partial crediting for force majeure outages because its recovery of 3 percent of fixed costs in usage charges is not "in the ballpark" with the risk sharing required under the Commission-approved "No Profit or Safe Harbor" approach.[71]

With respect to Northern Natural's compliance filing, the Commission required numerous changes. Rejecting Northern Natural's "hybrid" partial crediting proposal, which uses safe harbor no credit for the first fifteen days of force majeure outage, full credit for the next fifteen days, and no profit for periods after thirty days, the Commission found that the proposal amounted to cherry picking of the most favorable aspects of both approaches, which does not achieve an equitable cost-sharing.[72] The Commission rejected Northern Natural's proposal to limit partial credits to "Required Deliveries" (minimum quantities actually required by shipper to serve or otherwise meet firm market at primary delivery points) and a requirement that shippers file a claim that includes information supporting "Required Deliveries" (e.g., efforts shipper has taken to mitigate amount of reservation charge credits claimed) for the same reason that similar provisions were rejected in *Kern River Transmission Co*.[73]

70. N. Natural Gas Co., 141 FERC ¶ 61,221 (2012).

71. The Commission stated that its exemption of Tennessee from partial credit in Opinion No. 406, 76 FERC ¶ 61,022 (1997), where Tennessee allocates twelve percent of fixed cost to its usage rate, is no longer precedent for any particular percentage, and any pipeline's tariff provision for sharing of risk must be "in the same ballpark as the two approved methods approved for SFV-design pipelines." *Id.* at P 27.

72. The Commission noted that Northern Natural may propose to modify either the no profit or safe harbor method to reflect its inclusion of fixed cost in usage charges. Since approximately forty percent of Northern Natural's demand charges represent return and associated taxes, a no-profit credit of thirty-seven percent of fixed cost would be appropriate; for the safe harbor approach, an additional day of no crediting would be appropriate.

73. 139 FERC ¶ 61,044 (2012).

3. Texas Gas Transmission, LLC (RP12-820)

On December 20, 2012, the Commission approved Texas Gas Transmission, LLC's filing to amend its reservation charge crediting provision, subject to certain revisions.[74] Texas Gas proposed to include in its definition of force majeure testing, repair, replacement, refurbishment, or maintenance activity required under the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2012. While the Commission determined that this definition is overly broad because both the timing and compliance requirements are too speculative and unknown before the regulations are promulgated, the Commission did permit partial crediting for a transitional two-year period for compliance with one specific provision of the 2011 Act. Section 60139(c) of Chapter 601 of Title 49, permits PHMSA to require a pipeline to reconfirm MAOP and take interim action to maintain safety until MAOP is confirmed.[75] The Commission found that this particular provision is different from others in the 2011 Act because it does not require a rulemaking and PHMSA may issue an order at any time without advance notice of a rulemaking proceeding. The Commission also noted that the action PHMSA could require the pipeline to take would be a one-time, non-recurring event, the timing over which the pipeline has little control, which is different from routine, periodic maintenance that the Commission has held is within the control of the pipeline and thus not a force majeure event. The Commission also noted that outages for one-time testing or temporarily reduced operating pressures would not be recurring costs eligible for inclusion in a pipeline's rates in a general § 4 rate case. Finally, the Commission concluded that, although a pipeline's inability to verify MAOP on particular segments of its system may be attributable to a failure of the pipeline to maintain records, on balance it is preferable to include in a tariff a bright-line rule to minimize the need for burdensome case-by-case consideration.[76]

4. Rockies Express Pipeline LLC (RP13-423)

On January 31, 2013, the Commission accepted, subject to further revision, proposed tariff changes filed by Rockies Express Pipeline LLC (REX) concerning reservation charge crediting.[77] REX proposed a provision requiring shippers, in order to qualify for a reservation charge credit, to nominate through the evening cycle. However, shippers that have nominated on another pipeline after being curtailed in the timely cycle do not have to resubmit their nomination but must provide confirmation that another pipeline has scheduled. The Com-

74. Tex. Gas Transmission, LLC, 141 FERC ¶ 61,223 (2012).

75. PHMSA, the Pipeline and Hazardous Materials Safety Administration, is an agency of the Department of Transportation responsible for developing and enforcing pipeline safety regulations. A key element of such regulation is the determination of the maximum allowable operating pressure (MAOP) of the pipeline, based on design parameters, location of the pipeline, and other safety considerations.

76. Orders for similar provisions were issued for *Gulf South Co*., 141 FERC ¶ 61,224 (2012), and *Gulf Crossing Pipeline Co*., 141 FERC ¶ 61,222 (2012).

77. Rockies Express Pipeline LLC, 142 FERC ¶ 61,075 (2013).

mission accepted REX's proposal but required REX to push back the timing of when the shipper has to provide evidence of having submitted a nomination on an alternative pipeline to the end of the day of gas flow rather than during that evening cycle. The earlier requirement might mean a shipper that attempted but failed to schedule on another pipeline could miss out on REX credit through no fault of its own.

REX was also directed to revise its language clarifying that it is exempted from crediting where its failure to deliver was due solely to the conduct of the shipper or operating conditions on upstream or downstream facilities. If REX as well as other parties are unable to perform, force majeure credits would be due to shippers because REX was not ready to perform regardless of the condition on the upstream or downstream pipeline.

The Commission also required REX to modify its tariff to make it clear that the seven-day-before-outage measure of the quantity nominated (and hence eligible for credits) applies only where there is advance notice of force majeure outage and, in the case of an event lasting more than the safe harbor ten-day period, only if there is notice that the event would continue for the day in question. As for REX's proposal to use the same seven-day measure before the announcement of a monthly maintenance schedule, the Commission found it appropriate to allow such "anti-gaming" provision over REX's objections that it never made a specific showing of gaming and its claims that REX is different from Trans-Colorado because of its more frequent maintenance activity.

Finally, the Commission addressed protestors' requests that REX be required to adopt the no-profit form of partial crediting because of the large number of declared force majeure events, almost all of which were less than ten days in length with no credits given. In response to a Commission inquiry, REX reported that it had declared force majeure nineteen times since 2010 and only one event was longer than ten days. After noting that none of the protestors had contested the characterization of these events as force majeure events, the Commission declined to require REX to change its election of the safe harbor approach because the availability of that alternative is consistent with Commission policy.

F. Capital Cost Trackers

1. Columbia Gas Transmission, LLC (RP12-1021)

On September 4, 2012, Columbia Gas Transmission, LLC filed a settlement that proposed to implement a tracking mechanism, dubbed a capital cost recovery mechanism (CCRM), to recover the capital costs associated with modernizing its aging system.[78] The settlement identified specific "Eligible Facilities" projects for a period of 2013 through 2017. The CCRM would recover costs, up to $300 million annually (subject to a 15 percent tolerance), associated

78. Columbia would replace 1,442 miles of pipeline, replace compressors, expand in-line inspection capability, and install modern control systems.

with Eligible Facilities placed in service with the following conditions: (1) Columbia must obtain consensus of 75 percent of shippers (based on billing determinants) to add, remove, substitute, or modify an Eligible Facility; (2) Columbia will expend $100 million for capital maintenance that will not be recouped through the CCRM (the amount less than $100 million spent in a year would go to a reduction to plant investment); (3) Columbia would earn a return on capital costs of 14 percent; (4) in calculating the CCRM rate, customers would be protected by a minimum level of billing determinants, i.e., a billing determinant floor; and (5) the CCRM will be trued up for over- or under-recovery from the preceding year—with shippers protected by negotiated rate contracts being assumed to be at maximum rate and imputed discounted contract revenues if discounted transactions would reduce revenues below that which would result from the billing determinant floor.

The settlement also proposed rate relief for settling parties as follows: (1) $50 million in initial refunds; (2) additional relief from an annual $35 million rate reduction, retroactive to January 1, 2012, plus an additional reduction of $25 million annually beginning January 1, 2014, remaining in effect until the effective date of a subsequent NGA § 4 or § 5 rate change; (3) a revenue-sharing mechanism under which Columbia will refund 75 percent of base rate revenues over $750 million; and (4) a rate moratorium through January 31, 2018, and a requirement to file an NGA § 4 rate filing no later than February 1, 2019.

The only party that opposed the settlement was the Maryland Public Service Commission (MPSC). The MPSC asserted that a surcharge tracker is an inappropriate mechanism to recover capital costs, and challenged the 14 percent rate base multiplier.

On January 24, 2013, the Commission issued an order approving the settlement.[79] As a contested settlement, the Commission made a determination that the settlement was "just and reasonable" based on substantial evidence and a lack of genuine issues of material fact, and approved the settlement for all parties, including the MPSC and the local distribution companies subject to regulation by that agency.

With respect to the MPSC's objection to the CCRM surcharge on policy grounds, the Commission distinguished its rejection of other protested tracking mechanisms. The Commission, citing specific attributes, concluded that Columbia's CCRM provides a reasonable means to recover substantial costs without undercutting incentives to operate efficiently and maximize service to the extent that previously rejected surcharges would have done. First, the Commission noted that the refunds and rate reductions offer shippers relief that could not otherwise be obtained by shippers under NGA § 5 (prospective only), and that this relief assures that base rates, to which the CCRM surcharge will be added, "have been updated in a just and reasonable manner to reflect current circumstances on Columbia's system." Second, the specific identification of Eligible Facilities and

79. Columbia Gas Transmission, LLC, 142 FERC ¶ 61,062 (2013).

Columbia's commitment to spend $100 million for maintenance outside of the CCRM mechanism ensure that the costs that the CCRM mechanism recovers go beyond regular capital maintenance expenditures. Third, the Commission found that the recovery dollar cap and billing determinant floor and imputed revenue for discounted and negotiated rate contracts, were "critically important" because they subject Columbia to a continuing risk of under-recovery, thereby "alleviate the Commission's historic concern that surcharges which guarantee cost recovery are not appropriate for recovering capital cost because they diminish a pipeline's incentive to be efficient and to maximize service provided to the public."[80] Fourth, the Commission found that the CCRM is not permanent and is meant to recover a set amount of costs over a defined period. Finally, the Commission found the settlement to be broadly supported.

As to the objection to the 14 percent rate of return, the Commission found that there was no issue of material fact because the MPSC did not file an affidavit with its comments demonstrating an issue of fact over whether the use of fourteen percent would result in an unreasonable return.

G. Fuel and Other Trackers

1. Columbia Gas Transmission, LLC (RP12-605)

On April 13, 2012, Columbia Gas Transmission filed to implement a new surcharge to recover the costs of certain operational purchases and sales of gas required to ensure sufficient flows of gas into its system in northern Ohio to serve markets in that area and to fill storage fields. Columbia claimed that the influx of Marcellus shale gas into its system has resulted in a significant price discrepancy between its main pooling point and northern Ohio points where it interconnects with Panhandle Pipeline Co. and ANR Pipeline Co., resulting in precipitously low receipts. Columbia claims that arranging third-party transportation to move gas from the southern part of its system to northern Ohio (charged under its existing third-party transportation tracker) is more costly than making purchases of gas and making sales of the resulting oversupply system imbalance and recovering the net cost in a new operational transaction rate adjustment (OTRA) mechanism. Columbia requested that the Commission find that its proposal does not constitute an "unbundled sales service" subject to § 284.286 of the Commission's regulations because these are operational purchases and sales that should not trigger the "independent functioning requirement" of the Commission's standards of conduct. Alternatively, Columbia sought a limited waiver of § 284.286 to allow its transmission function employees to be involved in the sales of gas because they must be involved in the analysis of any bids or offers to make sure that they meet the operational needs of the system. Columbia also sought a waiver of the Commission's prohibition on buy/sell transactions.

80. *Id.* at P 25.

On May 22, 2012, the Commission issued an order approving the proposed OTRA mechanism.[81] The Commission found that this proposal is a just and reasonable solution to an operational problem because it provides a cost-effective mechanism, developed with input and support of customers, for addressing the reduced receipts in northern Ohio, and because the proposal is an interim mechanism that will only be in effect through March 31, 2014. In granting a waiver of its Standards of Conduct, the Commission noted that when it created the "incidental sales" exemption, it relied on commitments that there would be no regular merchant service and characterized the sales as occasional or involving minimal/insignificant volumes. The Commission noted that when faced with the question of characterizing exchanges of gas for the purpose of reducing transportation costs, the Commission determined that such exchanges would not be excluded from the definition of marketing functions.[82] Notwithstanding the similar purpose of the OTRA and the significant volume and transactions taking place on a daily basis, the Commission concluded that unique circumstances, the limited time period, and Columbia's commitment to an open and transparent process warrant a limited waiver of the independent functioning requirement. As for the waiver of its buy/sell prohibition, the Commission stated that the operational transactions Columbia will enter into as part of the OTRA do not appear to be buy/sell transactions. Accordingly, the Commission found that the transactions will not implicate its prohibition against buy/sell transactions.

2. Ruby Pipeline, L.L.C. (RP12-1013)

On September 28, 2012, the Commission issued an order on Ruby Pipeline, L.L.C.'s tracker filing to adjust its "fuel lost and unaccounted for" (FL&U) percentage.[83] Ruby reported an over-collection and, pursuant to its tariff, proposed to cash out the amount owed to shippers. Certain shippers protested the methodology for cash-out, which applied a lowest index price to gas owed to shippers. The Commission accepted Ruby's filing because it followed the provisions of its existing tariff. However, the Commission agreed with protestors that the tariff appears unreasonable because it treats the fuel adjustment as a penalty and allows Ruby to consistently undervalue refunds due shippers—against Commission policy that holds that neither the pipeline nor shippers should gain or lose as a result of fuel tracking. Pursuant to its § 5 authority, the Commission directed Ruby to revise its tariff or show cause why it should not be required to so do.

In its compliance filing, Ruby proposed to use the index price at the two points at which it receives almost all of its gas, weighted for the volumes received at each location. Protestors pointed out that Ruby's proposal does not address the show cause order's concerns because Ruby will gain and shippers will

81. Columbia Gas Transmission, LLC, 139 FERC ¶ 61,141 (2012).
82. Standards of Conduct for Transmission Providers, Order No. 717, FERC Stats. & Regs. ¶ 31,280, at P 93 (2008).
83. Ruby Pipeline, L.L.C., 140 FERC ¶ 61,256 (2012).

lose, based on the higher price Ruby receives at the point of sale. Therefore, according to the protestors, the appropriate price should be the weighted average price Ruby receives for its operational sales. The Commission in a February 8, 2013, order agreed with the protestors that Ruby should not be able to profit because it collected more fuel from its shippers than it needed to operate its system and the reasonable monetary value of such over-recovered gas is reflected in the price at the point of sale.[84]

3. Algonquin Gas Transmission, LLC (RP13-239)

On November 28, 2012, the Commission issued an order accepting and suspending Algonquin Gas Transmission, LLC's fuel tracker filing.[85] A protester objected to Algonquin's determination that certain transportation transactions are no longer backhauls because flows have reversed, and, therefore, a fuel charge applies to such service. The Commission has with a prior fuel filing determined that such reversal of flow and resulting change in fuel charges was a result approved when the Commission certificated Algonquin's HubLine/East to West Project. However, the current order found that it is not clear whether the direction of flows on all parts of Algonquin's system have changed and whether Algonquin's existing definition of backhaul remains just and reasonable, i.e., requires the direction of movement on the mainline be opposite to actual flow "at all times and at all points along the path." Accordingly, the Commission set the matter for technical conference. The fuel tracker was permitted to go into effect on December 1, 2012, subject to refund.

H. Major Tariff/Service Changes

1. Tennessee Gas Pipeline Co. (RP11-1566)

In a November 30, 2010, § 4 rate filing, Tennessee Gas Pipeline Co. proposed to change its scheduling priority for services. First, Tennessee proposed to elevate the priority for firm service from secondary receipt points to primary delivery points to the same level as primary receipt to primary delivery point when a restriction is within the shipper's primary capacity path. The Commission initially rejected this proposal as inconsistent with its policy of affording primary point to primary point the highest priority.[86] Seeking rehearing, certain parties argued that this modification is linked to the principal rationale of the Tennessee rate case—major change in flows and use of the system because of increase in downstream shale gas supplies—and is meant to allow customers to source these new supplies while retaining the ability to deliver during peak constrained periods. The Commission denied rehearing noting that primary point to primary point must be afforded the highest priority but it also clarified that pipelines

84. Ruby Pipeline, L.L.C., 142 FERC ¶ 61,104 (2013).
85. Algonquin Gas Transmission, LLC, 141 FERC ¶ 61,160 (2012).
86. Tenn. Gas Pipeline Co., 135 FERC ¶ 61,208 (2011).

are allowed to establish scheduling priorities that give secondary receipt to primary delivery points priority over primary receipt to secondary delivery points.[87] The Commission noted that when a shipper nominates service from a secondary receipt point that is within the primary path, the pipeline ordinarily should have sufficient mainline capacity to schedule the service to the primary delivery point, and, therefore, elevating such service to the highest priority level should be unnecessary.

Tennessee also proposed scheduling firm transactions using secondary points outside of the primary path by price (sum of reservation rate, commodity rate, fees, and surcharges). The Commission initially rejected the proposal, finding that price valuation based on annual reservation charges bears little relationship to deliveries to secondary markets on a particular day.[88] On rehearing, the Commission stated that while it continues to find Tennessee's proposal unjust and unreasonable because it discriminates against maximum rate short haul shippers, the Commission will clarify its policy because, as Tennessee pointed out, it has previously allowed scheduling of service to secondary points based on price. This clarified policy provides that pipelines may schedule firm secondary service by either the highest percentage of the applicable maximum rate or by the absolute price; however, if scheduled by absolute price, all shippers paying the maximum rate must be scheduled ahead of any discount rate shipper. The Commission stated further that pipelines are allowed to permit discount rate shippers an opportunity to increase their rate to enhance their priority on a particular day and clarified that pipelines may use either the releasing shipper or the replacement shipper's rate.

2. Gulf South Pipeline Co., LP (RP12-74)

On April 30, 2012, the Commission issued an Order on Technical Conference approving Gulf South Pipeline Co.'s proposal to allocate transportation quantities on a daily basis rather than its current practice of allocating on a monthly basis.[89] Gulf South claimed that when it restructured under Order No. 636, it implemented monthly allocation because it did not have the capability of providing daily measurement information but that situation has changed through upgrades in its metering. Gulf South proposed to charge its existing overrun rate for the shipper's use of capacity in excess of the shippers maximum daily quantity (MDQ). Gulf South claimed that this would ensure that customers pay for capacity they use and would eliminate free arbitrage, i.e., overrunning MDQ on individual days of the month without incurring charges based on market prices, which is equivalent to obtaining free parking and lending service. The Commission found that switching to daily allocation is reasonable and does not unduly harm shippers and allows the pipeline to more reliably recover costs from

87. Tenn. Gas Pipeline Co., 139 FERC ¶ 61,050 (2012).
88. 135 FERC ¶ 61,208.
89. Gulf S. Pipeline Co., 139 FERC ¶ 61,086 (2012).

customers that exceed their MDQ. The Commission stated that a pipeline need not demonstrate that its daily allocation proposal is necessary to meet some operational or market need; it is sufficient to show that the proposal will permit better system management going forward. The Commission rejected arguments that daily allocation can only be approved as part of a general § 4 proceeding because the proposed change results in a fundamental realignment of cost.[90] The Commission explained that for changes in the terms and conditions of a tariff that do not implement new services or change rates, it will defer rate-impact review to the next rate case, if the effects on cost and revenue are not substantial.

3. Columbia Gulf Transmission Co. (RP12-843)

On June 29, 2012, Columbia Gulf Transmission Co. filed proposed tariff changes that would provide that when shippers do not choose to process their own gas, it may arrange for the processing of gas flowing on its system and that it would own the extracted components. Columbia Gulf stated that its proposal would address increased production from shale plays, such as the Marcellus and Utica, which tend to have higher Btu and liquid content. A protester raised concerns that Columbia Gulf may use this authority to require shippers to "sign over" processing rights as a condition of access to transportation service or otherwise compel processing of gas that meets its quality specifications. Columbia Gulf responded by stating that it is seeking authority to process gas that has already been accepted on its system, and, therefore, the proposal in no way impacts a shipper's rights to deliver gas into its system.

In approving the proposed tariff changes, the Commission agreed that the proposal does not modify existing gas quality or interchangeability standards or in any other way impact shipper's ability to access Columbia Gulf's system. With respect to a proposal that Columbia Gulf be required to credit revenues from processing, the Commission noted that it has previously held that a pipeline need not include revenue crediting provisions in its tariff absent a specific harm or a showing that the proposal improperly impedes shippers' processing rights.[91]

4. Rockies Express Pipeline LLC (RP11-2096-002)

On October 1, 2012, the Commission issued an Order on Rehearing granting REX's request that it not be required to modify its backhaul rate schedule to allow customers to use secondary points to make forward-haul movements of gas.[92] The Commission found that a prohibition on such backhauls of backhauls, i.e., forward haul under a backhaul service, is appropriate where backhaul service is priced less than the standard firm transportation rate.

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90. Certain parties allege that a substantial quantity of storage operational capacity is allocated to support existing monthly balancing.

91. Panhandle E. Pipe Line Co., 61 FERC ¶ 61,357 (1992), *order on reh'g*, 62 FERC ¶ 61,288 (1993).

92. Rockies Express Pipeline LLC, 141 FERC ¶ 61,006 (2012).

The order denied a shipper's request for rehearing that argued that the Commission's order had not supported its finding that the new backhaul service did not degrade "in any significant way" the rate schedule firm transportation service (FTS) shipper rights. The shipper argued that backhaul service competes with FTS shipper releases of capacity, and, in particular, backhaul from primary points will have a scheduling priority over FTS from secondary points. In denying rehearing, the Commission stated that the shipper had cited no precedent for rejecting a new service on the basis that it would compete with existing customers in the capacity release market, and that, by definition, secondary point nominations have a lower priority than primary points so shippers were never guaranteed access to secondary points.

5. East Tennessee Natural Gas, LLC (RP12-1000)

On October 12, 2012, the Commission issued an order accepting tariff changes proposed by East Tennessee Natural Gas, LLC and three other pipelines regarding when a replacement shipper may be charged the same discounted or negotiated usage or fuel charge as that of the releasing shipper.[93] The proposed tariff provisions

- Allow the replacement shipper acquiring capacity on a temporary basis to request via the pipeline's electronic bulletin board (EBB) to pay the releasing shipper's usage and/or fuel rates. The pipeline will grant such request if it determines in a not unduly discriminatory manner that the potential replacement shipper is similarly situated to the releasing shipper;
- Provide that a denial will be via an e-mail explaining the reason (the recourse rate would apply); and
- Describe the procedure for documentation of the agreement.

Protestors argued that the provisions do not sufficiently describe "similarly situated" and that the timing of such determination would not allow a bidder for capacity to know what rate would apply before the close of bidding. The Commission rejected the protests as a collateral attack on the Commission's selective discounting policy and its order in *Texas Eastern* where it established that pipelines may, but are not required to, pass through discounted or negotiated usage or fuel charges and permitted pipelines to make such decisions on a case-by-case basis in accordance with its selective discounting policy.[94] As for the concerns raised by asset managers as to whether the replacement shipper will likely be similarly situated, the Commission again referred to *Texas Eastern*, in which it stated that the shipper is likely to be similarly situated when the asset manager steps into the shoes of the releasing shipper—e.g., where a releasing shipper was granted a delivery point discount and the replacement shipper provides service

93. E. Tenn. Natural Gas, LLC, 141 FERC ¶ 61,023 (2012).
94. Tex. E. Transmission LP, 129 FERC ¶ 61,031 (2009).

to the releasing shipper at that point. The Commission stated, "we cannot envision a scenario where the asset manager replacement shipper would not be deemed to be similarly situated to the releasing shipper."[95]

6. Gas Transmission Northwest LLC (RP12-15)

On November 6, 2012, the Commission issued an order on rehearing concerning Gas Transmission Northwest LLC's (GTN) proposed tariff language describing mutually agreed-upon pressure commitments to firm shippers. The Commission initially agreed that such commitments could only be entered into where the commitment would not alter available capacity. GTN sought rehearing or clarification. GTN acknowledged that its proposed tariff language would allow agreement that would reduce capacity available on its system by an amount greater than the contract quantity, but that GTN would not be allowed to alter its certificated capacity (i.e., GTN would only be allowed to adjust posted available capacity that is unsubscribed or affect its existing service obligations. In justifying pressure commitments that may reduce available capacity by more than the contract quantity, GTN noted that it has a significant amount of unsubscribed capacity and that such a tariff provision would help in marketing such capacity.

In the instant order, the Commission agreed with GTN, finding that if such pressure commitments enable GTN to obtain a firm shipper it could not otherwise obtain, all customers will benefit from the fixed-cost recovery. However, where such commitment will reduce unsubscribed capacity by more than contract demand, GTN must give notice of such prospective arrangement, thus giving other shippers an opportunity to obtain the capacity without such a pressure commitment. As for a concern raised by a protestor that such a pressure commitment could raise fuel rates if GTN uses more compression to increase pressure to serve such contracts, the Commission deemed such concerns "speculative" and noted that such issues can be raised in fuel adjustment filings.

7. Florida Gas Transmission Company, LLC (RP13-203)

On November 28, 2012, the Commission issued an order approving Florida Gas Transmission Company, LLC's (FGT) proposal to add an additional intraday nomination opportunity to accommodate flow changes for the final six hours of the gas day. This extra nomination opportunity would be available to all firm or interruptible shippers.

A protestor argued that any effort to provide increased services for designated users of the system, such as electric generation loads in this instance, should not affect the service of, or rates paid by, customers that do not require additional flexibility. The protestor claimed that the enhanced service would require software upgrades and operational changes that FGT will seek to

95. *Id.* at P 22.

recover from customers, including those not benefiting from the change in its next rate case. In approving FGT's proposal, the Commission noted that the additional flexibility is being provided at no charge. Further, all customers may take advantage of this flexibility. The Commission stated that it does not require that pipelines scale charges for generally available services on the basis of usage of the service.

I. Abandonment

1. Tennessee Gas Pipeline Co. (CP11-44)

On November 3, 2011, the Commission granted abandonment by sale from Tennessee Gas Pipeline to Kinetica Partners LLC of facilities that the Commission had determined to be primarily gathering facilities, but denied abandonment of facilities determined to be jurisdictional transmission facilities and directed Tennessee to re-functionalize immediately all facilities determined to be gathering.[96] The Commission also rejected a related customer settlement regarding the accounting and rate treatment for the facilities being sold. On rehearing, Tennessee argued that it had only applied for abandonment by sale under § 7(b) and did not request redetermination regarding the jurisdictional function of the facilities. Therefore, according to Tennessee, the Commission acted either arbitrarily and capriciously or beyond its authority under the NGA.[97]

In affirming its prior order, the Commission said that it generally has not analyzed the primary function of facilities as they are currently operating in proceedings where there are no continuity-of-service issues. However, in situations such as this—where the application is protested and the proposed abandonment is to an entity that would be a nonjurisdictional gatherer—its policy is to analyze the current function because, if the facilities are jurisdictional, the pipeline has a greater burden of proof to show that the public convenience and necessity permits the abandonment. Whether facilities subject to a protested abandonment are currently performing jurisdictional transmission is relevant, particularly because the Commission cannot deny a request for authorization to abandon facilities that are determined to be primarily performing gathering. With respect to the directive to re-functionalize those facilities found to be gathering facilities, even if they are not sold, the Commission stated that § 8 of the NGA gives it authority to require pipelines to retain any information the Commission may need to exercise its statutory responsibilities and specifically provides that the Commission may

96. Tenn. Gas Pipeline Co., 137 FERC ¶ 61,105 (2011). The order denied the abandonment by sale of the facilities found to be jurisdictional facilities because Kinetica had not filed an application for certificate authority to acquire and operate those facilities to provide interstate open-access transportation service.

97. Tennessee argued that Kinetica's request for a declaratory order on the jurisdictional status of the facilities required the Commission to determine only what the status would be if operated by Kinetica, and not what the primary function and jurisdictional status of the facilities are as currently operated by Tennessee.

prescribe a system of accounts. The directive to record gathering plant in the appropriate plant account was entirely consistent with this authority. As to Tennessee's argument that the facilities should not be re-functionalized because, as currently operated, they are certificated facilities used to transport gas subject to the jurisdiction of the Commission, the Commission noted that prior to open access unbundling, there was no need to review certificate applications to ascertain whether the facilities included gathering facilities. Consequently, before this proceeding, the Commission never had the occasion to analyze the status of the facilities. As to the application of the primary function test, the Commission disagreed with Tennessee's claim that it might have found none of the facilities to be gathering if it had given sufficient weight to Tennessee's general business activity as an interstate pipeline. The Commission stated that such nonphysical factors cannot be given much weight when physical factors clearly reveal the function of the facilities.

2. Transwestern Pipeline Co. L.L.C. (CP12-94)

On March 21, 2012, Transwestern Pipeline Co. sought authorization to abandon by sale to its affiliate, Lone Star NGL Pipeline, an approximately 59.5-mile-long segment of twenty-four-inch line that will be converted into a natural gas liquids line. Transwestern stated that the segment to be abandoned is entirely looped by a thirty-inch line that it will retain to provide natural gas transportation service.

In granting the abandonment, the Commission determined that continuity of service is assured because all active receipt and delivery points will be relocated to the thirty-inch line and the capacity of that line (500,000 Mcf per day) is well in excess of the present commitment of 250,000 Mcf/day.[98] In response to protests claiming that the facilities to be abandoned will be needed to transport future natural gas production from the Permian Basin, the Commission noted that no shipper claimed that current needs cannot be met and that Transwestern held an open season that resulted in no acceptable bids. The Commission stated that protesters are correct in noting that it considered the possibility in *Northern Natural Gas Co.*[99] that the proposal to take the Matagorda Offshore Pipeline System (MOPS) facilities out of service would make producers reluctant to invest in exploration in that area, potentially precluding as yet undiscovered reserves from development. However, the Commission explained that the greater concern in *Northern Natural* was shutting in current production. Transwestern's abandonment proposal is very different from the MOPS abandonment proposal: the remaining thirty-inch line has capacity significantly in excess of present firm obligations, and, therefore, the abandonment will not result in Transwestern being unable to continue service to existing customers. As to protester claims that the abandonment at fully depreciated cost to an affiliate would give that affiliate an

98. Transwestern Pipeline Co., 140 FERC ¶ 61,147 (2012).
99. 135 FERC ¶ 61,048, *reh'g denied*, 137 FERC ¶ 61,091 (2011).

unfair competitive advantage, the Commission stated that the proposed transfer to an affiliate at net book value is consistent with longstanding Commission policy.

3. Trunkline Gas Co. (CP12-5)

On October 7, 2011, Trunkline Gas Co., LLC filed an application to abandon by sale virtually all of its offshore facilities to Sea Robin Pipeline Co., an affiliated company. In its order approving the abandonment, the Commission emphasized the significance of the lack of protest by long-haul and firm shippers on Trunkline and shippers on Sea Robin.[100] The Commission emphasized the significance of interruptible shippers still having access in dismissing such shippers' concerns over the potential harm they would suffer. Specifically, the Commission found that although rates may increase for these shippers, because the rates will still be jurisdictional cost-based rates, such effects do not warrant a finding that the proposal is not permitted by the public convenience and necessity. The Commission rejected claims that the new arrangement resulted in rate stacking (from shippers paying both Sea Robin rates and the Trunkline rate when gas is delivered onshore) because the new arrangement amounted to a reallocation of costs and a splitting of the cost recovery into two separate approved cost-based rates.[101] The Commission rejected a request that Sea Robin be required to clarify its intent with regard to the jurisdictional status, finding speculation on what future proposals Sea Robin may have for the facilities to be inappropriate.

As for the rates Sea Robin may charge, the Commission denied its proposal to use its existing rate, instead requiring Sea Robin to develop incremental initial rates. The Commission determined that the facilities are stand-alone facilities that are not connected to Sea Robin's existing system. Incremental rates eliminate the possibility of existing customers subsidizing the new customers and vice versa, where there are no operational or service interrelationships that would support such rate treatment. The Commission denied Sea Robin's proposal to charge the users of these facilities its existing hurricane surcharge because the surcharge recovers costs for past hurricane damage and provides no benefit to the new customers on the acquired facilities. Sea Robin may file to recover new eligible costs resulting from future hurricane damage to the facilities.

On February 21, 2013, the Commission issued an order denying rehearing of its order approving abandonment.[102] In denying the rehearing requests of offshore producers, the Commission emphasized that the central focus of an NGA § 7(b) abandonment evaluation is not whether there is any harm to any

100. Trunkline Gas Co., LLC, 139 FERC ¶ 61,239 (2012).

101. The Commission noted that the same reallocation could have been accomplished by Trunkline by splitting its field zone into separate offshore and onshore rate zones in a § 4 rate case, in which case only the shippers using the offshore zone would be paying the higher rate of using both zones.

102. Trunkline Gas Co., 142 FERC ¶ 61,133 (2013).

narrow interest, but rather a broader view that evaluates the harm versus the benefits to the market as a whole.

The Commission stated that it is justified in relying on a lack of opposition from firm customers as persuasive evidence that there will be affirmative benefits to granting the abandonment. The Commission agreed that such customers will benefit from lower rates from the removal of the facilities from rate base in a future § 4 or § 5 rate proceeding.

The Commission rejected the producers' claim of harm from increased rates. The fact that the producers were not paying for the transportation service over Trunkline's offshore facilities did not mean that the service was free. To the contrary, other customers downstream of the pooling points were paying for and subsidizing that transportation. Being required to pay Sea Robin charges does not constitute an additional charge for the same service and the producers have not justified perpetuation of their competitive advantage over producers not enjoying the benefits of services paid by others.

The Commission also stated that it did not agree that interruptible customers require the same amount of protection as firm customers because they do not shoulder the same financial burden. Moreover, investors do not provide the capital necessary for constructing pipelines or continuing operations merely to serve interruptible customers at discounted rates.

The producers had argued that, in making a determination that certain facilities are non-jurisdictional gathering facilities, the Commission had deprived them of their procedural and substantive due process rights and had violated the Administrative Procedure Act because the Commission acted sua sponte and interested parties did not have notice and opportunity to comment. The Commission responded that a data request, which was served on parties, provided notice that the Commission was considering the primary function and the jurisdictional status of the facilities.

4. Southern Natural Gas Co. (CP12-4)

On June 21, 2012, the Commission issued an order approving Southern Natural Gas Co.'s application to abandon 604 miles of offshore and onshore Louisiana pipeline facilities by sale to a newly formed company, High Point Gas Transmission, which would operate the gas supply facilities as interstate transmission facilities.[103] Southern entered into a letter agreement with many of its customers in exchange for support of the abandonment. That agreement provided that Southern would seek regulatory asset recovery of the difference between the net book value of the facilities and the sales price.[104] High Point

103. S. Natural Gas Co., 139 FERC ¶ 61,237 (2012).

104. The net book value is $85 million while the sale price is $50 million. The $35 million would be recorded as a regulatory asset. Because the amortization period (three years) starts before Southern is required (by a prior rate settlement) to file its next § 4 rate case, the asset will be partially amortized before being reflected in customer rates.

proposed to provide firm transportation, interruptible transportation, park and loan service, pooling service, and title transfer service under a new tariff.

Southern claimed that its continued operation of these facilities is inconsistent with its efforts to provide high-value service to its customers, including efforts to diversify source of supply, limit the impact of hurricanes damage of offshore facilities, reduce dependence on Gulf of Mexico supplies, and add interconnections with pipelines with access to shale gas supplies. Southern estimated that current customers would benefit from a $4 million reduction in cost of service when its next § 4 rate case goes into effect, with the savings increasing to $15 million when the regulatory asset is amortized.

In approving Southern's abandonment request, the Commission found that continuity of service will be assured by High Point operating the facilities under Commission open access policies and regulations. While acknowledging that the protestors may not receive the rate reduction benefits of the abandonment, the support of firm shippers on Southern distinguishes this proposal from a rejected proposal where shippers holding the majority of firm capacity rights opposed the abandonment and the cost savings would not be passed on to shippers because of a rate moratorium.[105] The Commission also rejected the rate stacking claims of shippers that would be paying High Point's rates plus Southern's rate when gas is delivered from the High Point system to Southern for downstream delivery. The Commission acknowledged that under Southern's existing rates shippers upstream of Southern's pooling points do not pay for offshore transportation but concluded that does not mean that Southern provided the offshore service for free. Southern charged the shippers downstream of the pool for the upstream service. Thus, although the protestors are correct that they will now be paying both the High Point and Southern rates, that is a change in revenue responsibility, not rate stacking,

As for concerns over negative salvage Southern has been collecting for the subject facilities, the Commission determined that Southern's proposal to reduce its regulatory asset by this amount effectively returns negative salvage collection to its customers.

The Commission also conducted a primary function analysis for the facilities High Point proposes to acquire because they were constructed and certificated without such an analysis, and the possibility exists that some facilities perform a gathering function because of their location in an offshore production area,. The analysis showed that some facilities were gathering facilities while others are currently unused. For accounting and rate purposes, the Commission directed High Point to re-functionalize gathering facilities from transmission to gathering and not to include unused facilities in any initial transportation rate or any gathering service rate it may develop. The Commission also approved postage-stamp rates for High Point.

105. N. Natural Gas Co., 117 FERC ¶ 61,117 (2006).

As a new company providing service on existing facilities already long in service, the Commission stated that it has generally found it appropriate to use the most recent return on equity approved in a litigated § 4 rate case in developing initial rates. That rate is the 12.99 percent approved in *Portland Natural Gas Transmission*.[106] The Commission also approved High Point's use of its equity-thick, anticipated actual capital structure of 70 percent equity–30 percent debt. The Commission stated that this structure is appropriate because High Point is assuming greater than normal risk without firm customers and its operations in the Gulf of Mexico with declining supplies. The Commission also approved a hurricane surcharge tracker as part of High Point's proposed tariff.

5. Panhandle Eastern Pipe Line Company, LP (CP11-546)

On November 15, 2012, the Commission approved Panhandle Eastern Pipe Line Company's application to abandon its Adams Compressor Station in Texas County, Oklahoma.[107] No firm or interruptible shippers are currently being served by the facility; however, certain supplies attach to the Adams Compressor station and are moved by that facility under a no-fee pooling arrangement to downstream pools. Panhandle explained that the two protestors to its abandonment do not pay for this compression service and are subsidized by Panhandle's firm customers. Panhandle argued that these producers and supply aggregators could add compression upstream of the meter station that will remain in operation to deliver the gas at sufficient pressure into the Adams lateral or can reroute their gas on nearby gathering systems to deliver to other receipt points on Panhandle's system.

In approving Panhandle's proposed abandonment, the Commission determined that the abandonment would not "in and of itself result in the shut in of production" because other means of reaching the grid exist; the producers and other interests "will need to make business judgments as to whether it is economically feasible for them to pursue the alternatives."[108] The Commission also disagreed with the protestor's contention that in *Northern Natural Gas Co.* (*MOPS*)[109] it found that an NGA § 4 rate case is the appropriate means for a pipeline to deal with reducing cost rather than a § 7(b) abandonment application. The Commission noted that an approved abandonment is essentially a prerequisite for removal of costs from rates. The Commission explained that it was sensitive to the economic realities faced by pipelines in *MOPS* but continuity of service concerns prevailed.[110] Hence, *MOPS* does not stand for the proposition that it is inappropriate for a company to seek abandonment to reduce costs.

106. 134 FERC ¶ 61,129 (2011).
107. Panhandle E. Pipe Line Co., 141 FERC ¶ 61,119 (2012).
108. *Id.* at P 22.
109. 135 FERC ¶ 61,048 (2011).
110. The circumstances in *MOPS* differed from this case because MOPS shippers had no transportation alternatives for a significant proportion of the gas, whereas here production could be rerouted or field compression can be added. Also, the Commission noted that, in *MOPS*, shippers paid rates, albeit interruptible rates.

J. Infrastructure—Pipeline/Storage

1. Texas Eastern Transmission, LP (CP11-56)

On May 21, 2012, the Commission issued a certificate authorizing Texas Eastern Transmission, LP's New York Expansion project, which will provide 800,000 Dth per day of firm service to the New Jersey and New York metropolitan area from receipt points on Algonquin Gas Transmission, LLC near Ramapo, New York, and Mahwah, New Jersey, and a receipt point on Texas Eastern in Labertville, New Jersey.[111] Approximately 730,000 Dth per day of capacity will be provided through a twenty-year lease of capacity on Algonquin's system. Texas Eastern proposes to construct about twenty miles of new and replacement pipeline at an estimated cost of $789,493,884, and Algonquin would need to install facilities at an estimated cost of $67,524,524 to provide the leased capacity to Texas Eastern. Texas Eastern fully subscribed the project in an open season.

Although the Commission approved the proposed incremental firm rate, it rejected the interruptible (IT) rate, which is derived from that firm rate. The Commission explained that its policy is to require the pipeline to charge its current system IT rate for typical expansions (mainline looping or compression that expands capacity and is integrated with the existing system) because the pipeline is unable to determine whether the capacity available on any day is due to the existing facilities or expansion facilities. In this case, the Commission found that the New York Expansion project is an extension of Texas Eastern's existing system to a new delivery point in Manhattan, together with leased capacity on Algonquin. However, although the capacity extends Texas Eastern's system, the Commission concluded that it will nevertheless be integrated with the existing system. While charging an incremental rate would be inconsistent with its policy, the Commission also found that charging the applicable current zone rate would recover less than half the cost of the project. Accordingly, the Commission stated that it believes Texas Eastern could substantially accomplish its rate objectives in an acceptable manner by creating a new rate zone with separate maximum recourse rates for firm and interruptible service on the pipeline extension to Manhattan. Texas Eastern also proposed an incremental access charge for service on a secondary firm or interruptible basis for non–New York Expansion shippers using the leased capacity and the extension to Manhattan. The Commission rejected the access charge, stating that it has rejected similar access charges to use expansion capacity that is integrated with, and operated as part of, an existing system. But again, the Commission noted, Texas Eastern could propose a new rate zone that would enable it to recover from existing shippers the cost to transport on the extension.

On October 18, 2012, the Commission issued an order denying requests for rehearing of the May 18, 2012, order.[112] On rehearing, the Commission

111. Tex. E. Transmission, LP, 139 FERC ¶ 61,138 (2012).
112. Tex. E. Transmission, LP, 141 FERC ¶ 61,043 (2012).

sustained its invitation to Texas Eastern to create a new rate zone because that approach, with costs fully allocated to service in that zone, would prevent the subsidization by existing shippers of the rates of the shippers using expansion facilities to transport gas on a secondary or interruptible basis to the new delivery points in Manhattan along the new transportation path.

With respect to environmental challenges, the Commission's rehearing order addressed a broad range of requests. With respect to the cumulative impact of the NJ-NY Project and Marcellus Shale production activity, the Commission found no more than an attenuated relationship. The Commission found that this case, like *Sierra Club v. Clinton*,[113] involves new pipeline facilities found to be both physically and in terms of influence separated from production activity. The Commission stated that if two separate actions may proceed independently, the two actions are not conjoined in a cumulative impact analysis: the NJ-NY Project should operate for decades and, due to diverse sources of gas, it need never transport Marcellus supplies. Marcellus production can be expected to go forward for decades with or without the proposed project.

2. Chestnut Ridge Storage LLC (CP08-36)

On August 11, 2011, Chestnut Ridge Storage LLC requested a three-year extension of the August 31, 2011, deadline to complete its Junction Natural Gas Storage Project. The director of the Office of Energy Projects (OEP) issued a letter order denying the requested extension.[114] Chestnut Ridge filed for rehearing and on May 23, 2012, the Commission issued an Order Denying Rehearing and Vacating Certificate.[115]

On rehearing, Chestnut Ridge had objected to OEP taking note of the project's progress, arguing that expecting certificate holders to demonstrate concrete steps toward developing a project constitutes a new standard for granting an extension of time. Chestnut Ridge cited examples of other projects where no showing of progress or steps toward completion were demonstrated in approved extensions and where the sponsors referenced a downturn in the economy and the impact on the gas market as a reason for needing additional time. The Commission's rehearing order clarified its policy/rationale for denying extensions.

First, the Commission explained that the original certificate's time limit for completion is not arbitrarily established. Rather, it is based on the Commission's assessment of circumstances relevant to the specific project: the time needed for the project sponsor to conclude marketing efforts, complete construction, and make the project ready for service; and the time within which the Commission's findings supporting authorization can be expected to remain valid. The Commission stated that, in addition to information and data becoming dated, there could be anticompetitive implications associated with extensions of time. A certificate

113. 746 F. Supp. 2d 1025 (D. Minn. 2010).
114. Chestnut Ridge Storage LLC, Order Denying Request for Extension of Time, Docket No. CP08-36-001 (issued Nov. 2, 2011).
115. Chestnut Ridge Storage LLC, 139 FERC ¶ 61,149 (2012).

holder could thwart competitors, even when it has not started construction, because it could conceivably begin construction at any time with a certificate in hand, The Commission also noted that a certificate holder could constrain landowners from pursuing activities that are incompatible with the project's construction and operation. The Commission explained that, with most of the storage project extensions cited by Chestnut Ridge, construction was underway at the time the request was submitted and the projects were ultimately completed. By contrast, the Commission stated that "recent experience gives us cause to consider whether the same result (ultimate project completion within the extended time period) can be reasonably anticipated when the sponsor of a project which is still in the pre-construction stage seeks additional time based on market-related, as opposed to construction-related, setbacks." Given the potential changes in circumstances that underlay the Commission's original public interest findings and landowner concerns, a change in market is not a premise for putting a project on indefinite hold. It is reasonable for the Commission to weigh the impacts of authorized, but unconstructed, projects against the prospects for the project ever being completed and realizing its anticipated benefits.

Having held that Chestnut Ridge had failed to justify granting the requested extension, the Commission vacated the certificate.

3. Tennessee Gas Pipeline Co., L.L.C. (CP11-161)

On May 29, 2012, the Commission issued a certificate authorizing Tennessee Gas Pipeline Co., L.L.C. to construct and operate its Northeast Upgrade Project. This project essentially loops Tennessee's 300 Line System and would add 636,000 Dth/day of incremental capacity to the existing 300 Line System. The 300 Line System was recently upgraded by the 300 Line Project, which had a separate reliability component and a component to increase capacity by a 350,000 Dth/day incremental expansion (market component).[116] Tennessee calculated a monthly demand charge of $14.909 per Dth that combined the costs and design capacities of the 300 Line Project (market component) and the Northeast Upgrade Project. Tennessee claimed that the Northeast Upgrade Project will build upon the additional capacity created by the market component of the 300 Line Project, which was placed into service on November 1, 2011, and, as a result, the Northeast Upgrade Project costs are far lower than they otherwise would have been. Tennessee argued that absent this approach, Northeast Upgrade Project shippers would inappropriately benefit from the cheap expansibility while the shippers on the Line 300 Project bear all the cost of that construction.

The Commission certificate order rejected Tennessee's proposal because it would result in the total costs of the 300 Line Project market component being recovered in two separate rates at the same time. The Commission stated that although it would have been possible to amend the 300 Line Project rates to

116. Tenn. Gas Pipeline Co., 131 FERC ¶ 61,140 (2010).

reflect the costs of the Northeast Upgrade Project in a § 7 proceeding before that project went into service, once it went into service, the rates associated with that project can only be changed pursuant to NG§ 4 of the NGA.

The environmental review portion of the certificate order extensively discusses whether an environmental assessment (EA) or a more detailed environmental impact study (EIS) should have been prepared. The Sierra Club had argued that the project would significantly affect the quality of the human environment, thus requiring an EIS, because, among other things, the project would encourage rapid development of Marcellus Shale gas and that a more thorough EIS analysis is needed to consider the cumulative impact of the project on Marcellus Shale development. The Commission certificate order found that the EA adequately considered the general development of the Marcellus Shale region in the vicinity of the project, but the Commission was not required to include a more complete discussion of the development of the Marcellus Shale region because that is not causally related to the project, nor reasonably foreseeable. The Commission noted that the EA found that Pennsylvania had forecast 7.5 Bcf/day of production by 2015 and 13.4 Bcf/day by 2020, while the project would only transport 636,000 Dth per day—a very small percentage of the projected growth. Although the Commission conceded that there is a relationship between the project and Marcellus Shale development, given its lack of statutory authority to prevent the impact of wells, gathering lines, roads, and other development regulated by Pennsylvania, this link is not the "close relationship" that the courts have described. The Commission argued that the best analogy to the instant case is *Sylvester v. U.S. Army Corps of Engineers*,[117] where the decision to limit review to the impacts of the construction of a golf course for which the Corps issued a permit, rather than look at the impacts of the larger resort complex, was upheld because, while the golf course and the resort complex would each benefit from the other's presence, each project could exist without the other.

On January 11, 2013, the Commission issued an order on rehearing, clarification, and stay of its May 29, 2012, order.[118] On rehearing, the Commission granted Tennessee's request for clarification that it may file a limited § 4 filing to charge a rate that consolidated the cost of the project with that of the prior expansion.[119]

The Commission denied the Sierra Club's request for stay (no showing of irreparable harm) and to lodge new studies (no compelling showing of good cause). The Commission also denied the Sierra Club's allegation that the Commission impermissibly segmented National Environmental Policy Act (NEPA) review of the impacts of the project from the three other Tennessee projects on the 300 Line. The Commission found that each project is a stand-alone project. The Commission noted that the 300 Line Project was in operation before

117. 888 F.2d 394 (9th Cir. 1989).
118. Tenn. Gas Pipeline Co., 142 FERC ¶ 61,025 (2013).
119. The Commission noted that this is purely a procedural decision and does not address the merits of any such rate redetermination.

the MPP Project application was even filed and concluded that Sierra Club's approach is "unworkable" and would unduly delay infrastructure development. Under the approach, Commission would have to delay environmental review of the 300 Line Project, the NSP Project, and the Northeast Upgrade Project until the MPP Project was proposed. The Commission stated that Sierra Club's arguments are largely premised on the fact that subsequent expansion projects were designed based on the facilities proposed in earlier projects and concluded that the fact that existing and previously proposed infrastructure will impact the design of subsequent capacity merely reflects engineering principles. It does not demonstrate that the projects are connected and cannot move forward independently for purposes of NEPA analysis; each of the projects is designed to provide service to specific customers and can stand alone. The Commission determined that the Sierra Club did not show that the projects were economically interdependent: the only showing was that costs might be lower because of prior construction and no evidence was proffered for the contention that without the cost savings from the 300 Line Project, Tennessee would not have been successful in contracting for the project. The Commission stated that courts have held that improper segmentation is concerned with projects that have reached the proposal stage, which is not the case here; the EA for the 300 Line Project was issued before the certificate proposals for any of the other projects were filed.

The Commission also rejected Sierra Club's claim that the Commission had failed to address the cumulative impact of the project and other projects on the development of Marcellus Shale resources, finding that the project is designed as a high-capacity pipeline supporting Tennessee's entire system (not a gathering system for shale gas), and that development in the Marcellus Shale region will continue without the project and unregulated developers will continue to build new wells and gathering systems to serve shale gas.

4. Dominion Transmission, Inc. (CP12-72)

On December 20, 2012, the Commission approved an application by Dominion Transmission, Inc. (DTI) to construct and operate compression, pipeline, and storage facilities located in Maryland, Ohio, West Virginia, and Pennsylvania (Allegheny Storage Project), which will enable DTI to provide an additional 115,000 Dth/day of firm transportation, 7.5 Bcf of firm storage, and 125,000 Dth/day of storage withdrawal service.[120]

The Allegheny Storage Project faces substantial environmental challenges, particularly from the Town of Myersville, Maryland, where DTI proposes to site a compressor station. The Myersville Citizens for a Rural Community (MCRC) assert that the application should be rejected because the Town Council had denied DTI's zoning application to site the compressor station; without zoning approval, DTI is barred from even applying to the Maryland Department of Environment (MDE) for a Clean Air Act permit. In denying the MCRC request for rejection,

120. Dominion Transmission, Inc., 141 FERC ¶ 61,240 (2012).

the Commission noted that the NGA preempts state and local regulations to the extent they conflict with federal regulation or would delay construction and operation of approved facilities. However, the Commission declined to address the specific claims with regards to MDE action because that would involve the Commission interpreting local, state, and federal laws outside of its jurisdiction. The Commission stated that the state and local agencies retain full authority to grant or deny the air quality permits—“if Maryland rejects DTI’s air quality permit application, or refuses to process it, then it is up to DTI to determine how it wishes to proceed.” The Commission did not elaborate on the available recourse.

K. Infrastructure—LNG

1. The Gas Company, LLC (CP12-498)

On January 17, 2013, the Commission dismissed an application by The Gas Company, LLC for NGA § 3 authorization to operate facilities to receive containers of LNG transported from the Continental United States to Hawaii and re-gasify the LNG for distribution.[121] Gas Co. stated that it plans to purchase twenty International Shipping Organization (ISO) containers, which would be filled in the Continental United States with LNG from domestic sources and transported via container ship to Gas Co.’s existing Pier 38 facilities in Honolulu Harbor. Gas Co. filed an application for § 3 authorization because the EPAct 2005 added a definition of “LNG terminal” that encompassed facilities handling solely domestic gas if the gas has been or will be “transported in interstate commerce by waterborne vessel.” The Commission, in a case of first impression, determined that Gas Co.’s existing pier facilities that will receive, load, and unload the vessels carrying the ISO containers of LNG also handle other products; therefore, in the Commission’s view, they are not “natural gas facilities” as the term is used in the EPAct 2005 definition.

The Commission also found that Gas Co.’s proposed operation will be exempt from Commission NGA jurisdiction because it qualifies as either exempt local distribution under § 1(b) of the NGA or an exempt Hinshaw company under § 1(c). In short, the Commission found that no aspect of Gas Co.’s proposed activity is jurisdictional.

2. Northern Natural Gas Company (CP13-53)

On January18, 2012, Northern Natural Gas Co. filed an application to amend its certificate for an existing Garner Plant LNG facility in order to construct and operate facilities to offload LNG to LNG tractor-trailers for its own operational use and delivery service to third parties. Northern Natural explained that it is conducting an increasing amount of hydrostatic testing. In order to

121. The Gas Co., 142 FERC ¶ 61,036 (2013).

maintain service while testing, it has historically contracted with third parties to purchase LNG and deliver and re-gasify the LNG for injection at the testing sites. In an effort to reduce cost, Northern has purchased two LNG tractor-trailers and vaporization trailers that can hold 850 Mcf each. The offloading facilities at the Garner Plant would, according to Northern Natural, optimize use of the LNG tractor-trailers to support operation and maintenance activity. Northern Natural sought a presumption of rolled-in rate treatment because the primary purpose is to support system operation. However, Northern Natural also proposed to offer delivery service to third parties under a new rate schedule.

L. Infrastructure—Pipeline Export

1. Sabine Pass Liquefaction, LLC (CP11-72)

On January 31, 2011, Sabine Pass Liquefaction, LLC filed an application for authorization under § 3 of the NGA to site, construct, and operate facilities for the liquefaction and export of up to 16 million tons per annum (equivalent to 2.2 Bcf/day) of gas. The facilities will be able to operate simultaneously with the currently operating LNG import facilities.

On April 16, 2012, the Commission issued its § 3 authorization.[122] Given the simultaneous import and export operation, one import customer raised jurisdictional issues concerning the potential for gas liquefied for export being re-gasified and delivered back into the interstate market or imported LNG being comingled in the same tank as domestically sourced LNG. The Commission responded that neither the export nor import affiliates at the facilities have requested or are being granted authority to store interstate gas for reintroduction into the interstate market. With respect to any potential adverse impact that export may have on domestic consumers of gas and on national security, the Commission noted that under authority delegated by the Secretary of Energy, the Commission approves or disapproves of the siting, construction, and operation of facilities but does not authorize the import or export of the commodity itself. DOE's Office of Fossil Energy authorizes the import and export of the commodity and found the export to be not inconsistent with the public interest in a prior order. With respect to environmental issues, the Commission determined that the preparation of an EA, instead of a more comprehensive EIS, was appropriate because all of the proposed facilities would be within the footprint of the existing LNG terminal, which was previously subject to an EIS. With respect to claims that the Commission must consider the indirect impact of the project encouraging additional shale gas production, resulting in increased air and water pollution, the Commission stated that the NEPA/Council on Environmental Quality (CEQ) regulations require consideration of indirect impacts that are "reasonably

122. Sabine Pass Liquefaction, LLC, 139 FERC ¶ 61,039 (2012).

foreseeable." The impact of the project on shale gas development is not reasonably foreseeable. The Commission explained that while the project will support increased shale gas production, no specific shale-gas play can be identified—Sabine Pass will receive gas from multiple interconnected pipelines that cross multiple shale and conventional gas plays—so it cannot estimate how much of the export will come from current shale gas production and how much, if any, would come from new production attributable to the project. The Commission concluded that considering such impacts and developing a meaningful analysis would be "impractical."[123]

On July 26, 2012, the Commission issued an order denying rehearing and stay of its certificate order.[124] On the issue of the indirect impact on shale gas production, the Commission clarified that it did not conclude that it was not "reasonably foreseeable" that the project would induce increased gas production; rather its order stated that it is virtually impossible to estimate how much, if any, of the export volumes will come from existing or new shale gas production, nor the timing and location of any new development. The Commission stated that even if it were confident that the project would induce development in a particular area, the scope and timing of such future wells and the associated development (roads, well pads, and other infrastructure) are unknowable, and, therefore, the Commission is not in a position to provide a meaningful analysis of the potential impacts.

On February 21, 2013, the Commission issued a certificate to Cheniere Creole Trail Pipeline, L.P. authorizing the construction and operation of pipeline facilities that would enable bidirectional flow on its system so that domestic gas can be delivered to Sabine Pass.

2. El Paso Natural Gas Co. (CP12-6, CP12-7)

On October 12, 2012, the Commission issued an order approving El Paso Natural Gas Co.'s (El Paso) proposal to reconfigure its Willcox Compressor Station from mainline service to lateral service to provide additional transportation capacity to Mexico from 208,000 Mcf/day to 446,000 Mcf/day.[125] However, the Commission denied El Paso's request for a predetermination supporting rolled-in rate treatment after determining that the discounted rates will fail to meet annual costs. The Commission granted El Paso's proposal to implement a new fuel charge for the new lateral customers because the reconfiguration is largely a compression-based expansion. However, because existing firm service on the lateral had been served without the use of compression, consistent with its "no-subsidy" requirement, the new charge will not apply to such customers, including overrun and secondary point service. The Commission also rejected El Paso's proposal to

123. The Commission explained that one CEQ principle for such analysis states that "it is not practical to analyze the cumulative effects of an action on the universe; the list of environmental effects must focus on those that are truly meaningful."

124. Sabine Pass Liquefaction, LLC, 140 FERC ¶ 61,076 (2012).

125. El Paso Natural Gas Co., 141 FERC ¶ 61,026 (2012).

charge fuel for IT service because interruptible service on the lateral pre- and post-reconfiguration would be the same service on an integrated facility.

M. Significant FERC Rate Cases

1. El Paso Natural Gas Co. (RP08-426)

On May 4, 2012, the Commission issued Opinion No. 517, which addressed issues that were reserved for hearing from El Paso Natural Gas Co.'s 2006 § 4 rate case and settlement.[126] The first issue concerned the roll-in of the purchase price of a converted oil pipeline. In 2000, El Paso had purchased a 1,088-mile crude pipeline for conversion to natural gas service. The line was separated into three segments, and the purchase price (cost) was allocated to the segments based on mileage. The first segment (Line 2000), which was allocated $93.1 million in purchase cost, was certificated in 2001.[127] In the certificate proceeding to put into service the second segment (Line 1903), El Paso initially sought a predetermination of rolled-in rate treatment for the entire balance of the purchase cost ($36.2 million) but agreed to limit such predetermination to the costs attributable to the 87.8 miles of pipeline ($10.5 million) being placed into service.[128] When El Paso sought to roll in the remaining $25.7 million purchase price in the 2006 rate case, the administrative law judge (ALJ) rejected the proposal because that amount was allocated to the remaining unconverted segment of pipe that was found not to be "used and useful." El Paso argued that the full $36.2 million cost, plus the cost of conversion, is more than $100 million less than the cost of building a new eighty-eight-mile pipeline, and that during the test period, revenues from the line far exceeded the cost of service with the full $36.2 million in rate base. El Paso claimed that in order to purchase the entire pipeline it had to agree to the purchase of unconverted segment; thus, the $25.7 million allocated to that segment is a necessary expense associated with Line 1907. In Opinion No. 517, the Commission affirmed the AJL's disallowance of the roll-in because it is "undisputed" that the segment is not used and useful. The Commission also rejected the system benefits' claim to justify roll-in, stating that although its Certificate Policy Statement does approve rolled-in rate treatment for the entire cost of projects whose costs do not exceed revenues, that principle does not address the determination of a particular asset cost.[129]

For the second issue, Opinion No. 517 upheld the ALJ's adjustment to El Paso's proposed capital structure, which reduced the equity component to reflect removal of a cash management program balance of $615 million and removal of $145 million in undistributed subsidiary earnings. Opinion No. 517 upheld the

126. El Paso Natural Gas Co., 139 FERC ¶ 61,095 (2012).

127. El Paso Natural Gas Co., 95 FERC ¶ 61,176 (2001).

128. The remaining 215 miles of unconverted pipeline (California Segment) were, therefore, allocated the remaining $25.7 million.

129. The asset cost was found to be the actual acquisition cost of the eighty-eight-mile segment: $10.7 million based on the original mileage allocation.

ALJ on both actions, finding that El Paso does not use these monies to provide jurisdictional service to its customers. The Commission rejected El Paso's argument that the Opinion 414 line of cases[130] supported the use of its actual, unadjusted capital structure, finding that those cases only discuss whether it was appropriate to use the pipeline's own capital structure or that of its parent. In this case, all parties had agreed to use El Paso's structure. Instead, what is at issue is whether some elements of that capital structure are not devoted to jurisdictional service and should be excluded. The Commission rejected El Paso's claim that it is Commission policy to require a party seeking to exclude certain items to assume the burden of "tracing" the source of the assets to a specific equity issue. The Commission cited a string of cases where tracing did not take place to demonstrate that tracing is case-specific and not a "controlling factor" with the focus on whether the end result is just and reasonable.[131] In any case, the Commission found that debt tracing is unnecessary because the total amount can be considered equity; once earned, those monies represent additional equity available to the pipeline to dispose of at its discretion.

With respect to the cash management program, the Commission found that by lending funds to its parent, El Paso had limited its own liquidity.[132] Because it was alleged that El Paso had not received adequate compensation for such loans, there was sufficient basis to question the reasonableness of the use of such loan amounts for capitalization purposes, such that "the burden properly shifts to El Paso to demonstrate that its proposed equity ratio is just and reasonable." With respect to claims that "ring-fencing" measures should be adopted for the future to prevent El Paso from unlawfully subsidizing its affiliates while transferring risk to its customers, the Commission affirmed the ALJ's finding that such measures are not needed because the exclusions from the capital structure provide adequate protection of ratepayers.

Opinion No. 517 also affirmed the ALJ's rejection of El Paso's proposal to charge maximum rates for short-term firm, IT, PAL, and authorized overrun equal to 250 percent of the maximum reservation component of recourse rates applicable to long-term firm service, plus the applicable commodity component, and to credit 90 percent of revenues in excess of the firm maximum rate once El Paso collects its annual cost of service. The Commission found that, in proposing short-term rates as part of its § 4 rate case, El Paso had the opportunity to project revenues and allocate costs among services, as required by Order No. 637, but had failed to do so. The Commission found that El Paso had proposed a mix of peak/off-peak rates and term differentiated rates, cherry picking the most favorable aspects, but failed to meet the requirements of each under

130. Transcon. Gas Pipe Line Corp., Opinion No. 414, 80 FERC ¶ 61,157, *order on reh'g*, Opinion No. 414-A, 84 FERC ¶ 61,084, *order on reh'g*, Opinion No. 414-B, 85 FERC ¶ 61,323 (1998), *aff'd sub nom.* N.C. Utils. Comm'n v. FERC, 203 F.3d 53 (D.C. Cir. 2000).

131. El Paso claimed that the lack of record evidence tracing the source of the loan monies should mean the amount should be split along the same debt/equity ratio as its proposed capitalization.

132. The Commission found that the $615 million in the program was not in El Paso's hand at the close of the test year such that the funds were not "available" to El Paso.

Order No. 637. El Paso proposed a maximum peak rate available every day of the year but had not designated any lower off-peak rate, thereby failing the requirement that increases in rates at peak must be offset by decreases in off-peak rates. The Commission also rejected the revenue crediting proposal, finding that Order No. 637 only contemplated revenue crediting for peak/off-peak rates proposed between rate cases where pipelines do not have the opportunity to reallocate costs. Order No. 637 does not contemplate revenue sharing for term-differentiated rates at all: it must be proposed in a § 4 rate case where revenue responsibility is reallocated.

Opinion No. 517 affirmed the ALJ's determination that a 1996 settlement rate cap that applied to the rates of certain shippers, pursuant to article 11.2 of the settlement,[133] should not be eliminated under the *Mobil-Sierra* "public interest" standard. The Commission stated that it cannot find on the record that (1) El Paso's article 11.2 revenue shortfalls, to the extent they occur, have clearly impaired its financial stability or ability to provide service or (2) competitive advantages held by capped rate shippers have resulted in such actual harm to the general public that rescission of article 11.2 is warranted.[134] The Commission agreed with the ALJ that there is insufficient evidence that article 11.2 will impair the financial ability of El Paso to provide service, impose excessive burdens on third parties, or be unduly discriminatory. The Commission found that so long as El Paso agreed to provide service to a discrete set of customers at capped rates, it always faced the prospect of revenue shortfall. As for the argument that article 11.2 distorts natural gas and electric markets by giving article 11.2 shippers a rate advantage, the Commission found that such comments do not chronicle any extraordinary or widespread market dysfunction, but merely reflect the fact that El Paso's various customers take service at varying rates. With respect to El Paso's claim that it can collect shortfalls caused by article 11.2 from other customers, the Commission agreed with the ALJ that El Paso may not reallocate such costs because it had not met its burden under the Commission's Discount Rate Adjustment Policy (discounts required to meet competition) and presented no other viable justification for such reallocation. The Commission determined that article 11.2 was not negotiated to adjust individual customer rates in recognition of competitive alternatives, but, rather, was negotiated as a global settlement to resolve the issue of how to allocate the risks and costs associated with turned-back capacity.

2. El Paso Natural Gas Co. (RP10-1398)

On June 18, 2012, the presiding ALJ issued an initial decision (ID) on El Paso Natural Gas Co.'s § 4 rate increase filing. One of the most significant findings of

133. *See* El Paso Natural Gas Co., 79 FERC ¶ 61,028, *reh'g denied*, 80 FERC ¶ 61,084 (1997) (1996 Settlement Order).

134. According to the Commission, it must presume that the rates in the agreement are just and reasonable, and such presumption can only be overcome if the Commission concludes that the contract seriously harms the public interest.

this massive ID is that El Paso has made a very persuasive case that it should be placed above the recommended proxy group median return on equity. The ALJ found that business risk was particularly high and anomalous because (1) average remaining contract life is appreciably shorter than industry and the proxy group average; (2) low and declining throughput elevate both business and regulatory risks; (3) El Paso has higher gas supply costs and fuel costs than competitors; (4) El Paso faces enhanced competitive/business risk (including regulatory action) in its primary California and Arizona markets; and (5) about 50 percent of its long-term firm capacity is subscribed under "sculpted" contracts (capacity entitlement varying from month to month). The ALJ stated that each factor alone is at the least uncommon but, in the aggregate, they are rare and perhaps unique.

The ALJ approved El Paso's proposal to continue to set rates on a five-zone basis (state boundaries defining zones) with each zone's rate being determined by allocating costs based on the average contract path distance. The ALJ found that El Paso's system is "reticulated," i.e., (web-like with transactions moving in multiple directions) in contrast with "long-line" pipelines (where gas is taken in on one end and delivered on the other end). This makes it impossible to determine the actual sources and delivery paths, i.e., the physical path, for most gas transported and to determine rates on that basis. The ALJ also stated that allocating fixed costs based on capacity rights acknowledges that installed capacity is the major cost driver. As for El Paso's proposal to average the costs for its three western-most zones, California, Arizona, and Nevada, to establish identical rates, the ALJ found the proposal to be completely at odds with nearly every argument El Paso made to support its contract path methodology. The ALJ noted that contract path methodology was supported by El Paso because it still has at least some distance sensitivity but averaging the three states would dampen such sensitivity. The ALJ found that El Paso had not supported what amounts to creating a hybrid rate design—distance-sensitive rates for two zones, Texas and New Mexico, and a postage-stamp rate for California, Arizona, and Nevada.

With respect to the issue of whether El Paso should be allowed a full discount rate adjustment, the ALJ found entirely in El Paso's favor. The ALJ concluded that it is misleading to characterize any proposal to deny El Paso the full test-period discount adjustment as a form of "risk sharing" because such proposals guarantee a shortfall for El Paso. Such proposals reflect retroactive "cost sharing," rather than a prospective sharing of risk going forward. The ALJ stated that forward-looking risk sharing is acceptable because it is axiomatic that a regulated entity is not guaranteed full recovery, but it is equally axiomatic that a regulated entity cannot be constitutionally denied a reasonable opportunity to fully recover its prudent costs.[135] The ALJ found that none of the hearing participants had disputed El Paso's claims that discounting was needed to meet competition; indeed, the record is unequivocal about the need for discounting.

135. The ALJ cited *FPC v. Hope Natural Gas*, 320 U.S. 591 (1944); *Bluefield Water Works and Improvement Co. v. PSC*, 262 U.S. 679 (1923).

The ALJ found that while the Commission's *Policy for Selective Discounting by Natural Gas Pipelines*[136] considers the possibility that full discount adjustment might increase rates to the point they become unjust and unreasonable or unduly discriminatory against captive/recourse rate shippers, none of the cost-sharing proponents had demonstrated that was the case (e.g., no comparison with rate data from other pipelines), and none had provided a rational basis for imposing the discount capacity cost on El Paso.

3. Northern Border Pipeline Co. (RP12-1093)

On December 5, 2012, the Commission issued an order approving a settlement Northern Border Pipeline Co. filed in lieu of its obligation to file a § 4 rate case that arise out of a prior rate case settlement condition.[137] The settlement (1) provides for a reduction in rates; (2) permits Northern Border to make a limited § 4 filing to adjust rates to reflect costs for complying with new regulations and legislation, e.g., greenhouse gas emissions, requirements to use emission control technology issued by EPA, additional pipeline safety requirements issued by DOT, and FERC-mandated initiatives, provided that the cost of service impact exceeds $15 million annually; and (3) provides that Northern Border is precluded from making a general § 4 rate filing before January 1, 2016, and must make such a filing no later than January 1, 2018.

The Commission rejected a provision that would impose the *Mobil-Sierra* public interest standard of review on any future changes to the settlement following its approval.[138] The Commission found no compelling reason to impose the more rigorous application of the "just and reasonable" standard of review to future changes to settlements sought by either the Commission or non-settling third parties.

136. 111 FERC ¶ 61,309, *order on reh'g*, 113 FERC ¶ 61,173 (2005).
137. N. Border Pipeline Co., 141 FERC ¶ 61,190 (2012).
138. United Gas Pipeline v. Mobile Gas Serv. Corp., 350 U.S. 332 (1956); FPC v. Sierra Pac. Power Co., 350 U.S. 348 (1956).