# REPORT OF THE COMPETITION & ANTITRUST COMMITTEE

This report summarizes antitrust and competition developments that occurred in 2012.*


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## I. FILED RATE DOCTRINE COURT CASES

### A. *Simon v. KeySpan Corp.*

Charles Simon filed a class action in the Southern District of New York against KeySpan Corp. (KeySpan) and Morgan Stanley Capital Group, Inc. (Morgan Stanley) on behalf of New York City customers who purchased electricity from Consolidated Edison Company of New York, Inc. (Con Ed) between 2006 and 2009.[1] The complaint alleged a violation of section 1 of the Sherman Act in the form of anticompetitive conduct in the New York City capacity market, where capacity rates are set according to a market-based auction system.[2] In 2006, KeySpan and a rival producer separately entered into offsetting swap and hedge agreements with Morgan Stanley, which created payment obligations to and from Morgan Stanley based on the spread between the auction price and a fixed price delineated in the agreements.[3] The arrangement entitled KeySpan to payments from Morgan Stanley if the auction price exceeded the stipulated fixed price.[4] KeySpan allegedly had an incentive to bid its capacity at a price equal to a bid cap imposed by the Federal Energy Regulatory Commission (FERC).[5] But for the swap and hedge agreements, KeySpan allegedly would have bid its capacity below the cap because new generation capacity was then coming online in New York City.[6] The Department of Justice also investigated this conduct and entered into consent decrees with KeySpan agreeing to disgorge $12 million and Morgan Stanley $4.8 million.[7]

In 2011, the district court granted the defendants' motion to dismiss Simon's complaint, finding that Simon lacked standing as an indirect purchaser and that the filed rate doctrine barred private antitrust suits for damages in wholesale electricity markets.[8] In September 2012, the Second Circuit affirmed,[9] ruling that Simon's federal claims were barred by the Supreme Court's decision in *Illinois Brick Co. v. Illinois*,[10] which limits indirect purchaser standing in suits under the federal antitrust laws.[11] The court noted that indirect purchaser suits could expose defendants to duplicative liability and would

1. Simon v. KeySpan Corp., 694 F.3d 196, 201 (2d Cir. 2012).
2. *Id.* at 199, 201.
3. *Id.* at 199-200. An additional fixed spread of fifty cents per kilowatt hour was built into the fixed price in the swap and hedge agreements to compensate Morgan Stanley. *Id*. at 200.
4. *Id.*
5. *Id.*
6. *Simon*, 694 F.3d at 200.
7. *Id.* at 200 & n.5.
8. Simon v. KeySpan Corp., 785 F. Supp. 2d 120, 134, 138 (S.D.N.Y. 2011).
9. *Simon*, 694 F.3d at 208.
10. Illinois Brick Co. v. Illinois, 431 U.S. 720 (1977).
11. *Simon*, 694 F.3d at 202.

require complex damage calculations that involve "too many 'uncertainties and difficulties.'"[12]

The court ruled that the cost-plus contract exception to the *Illinois Brick* rule did not apply to Simon's claim. An indirect purchaser may bring an antitrust suit under the cost-plus contract exception if it "has agreed in advance to purchase a fixed quantity, paying the direct purchaser's costs plus a predetermined additional fee."[13] Under these circumstances, the defendant can avoid duplicative liability by invoking the pass-on defense, and damages are simpler to compute because the direct purchaser has passed on the entire overcharge to the indirect purchaser.[14] While Con Ed, the direct purchaser, passed on 100% of its capacity costs to its customers, the court observed that Simon was not obligated to purchase a fixed amount of electricity[15] and the overcharge may have led to reduced power consumption by Simon and other class members.[16] Furthermore, absent the overcharge, Con Ed may have obtained a rate increase from the state regulator.[17]

The court also held that the filed rate doctrine barred the plaintiff's suit for damages. The Supreme Court established this doctrine in *Keogh v. Chicago & N.W. Ry. Co.*[18] to prohibit private antitrust suits seeking damages in regulated industries.[19] The court stated that the *Keogh* decision was based on three considerations: the reduced need for antitrust enforcement in regulated industries, the per se legality of regulated rates, and the difficulty of determining whether a lower rate would have received regulatory approval.[20] Permitting parties to challenge rates in court could lead to non-uniform rates and a violation of the non-discrimination principle.[21] The court stated that the filed rate doctrine is an absolute bar if a private antitrust claim could lead to discriminatory rates and undermine the exclusive authority of federal agencies in approving rates.[22]

The court ruled that the filed rate doctrine barred Simon's claim because the FERC "sufficiently safeguarded" the capacity auction.[23] The FERC imposed bid caps on generators whose capacity would be necessary to meet demand.[24] It investigated KeySpan's financial swap and found that it "did not constitute fraudulent market manipulation."[25] Because it concluded that the FERC "tightly controls the auction process and has exercised its ability to undertake individual review of the MBR to ensure that anti-competitive practices did not undermine the process it created," the court refused to second guess the FERC's "carefully

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12. *Id.* at 202 (quoting *Illinois Brick,* 431 U.S. at 731).
13. *Id.*
14. *Id.*
15. *Id.* at 204.
16. *Simon*, 694 F.3d at 203.
17. *Id.*
18. Keogh v. Chicago & N.W. Ry. Co., 260 U.S. 156 (1922).
19. *Simon*, 694 F.3d at 205.
20. *Id.*
21. *Id.*
22. *Id.*
23. *Id.* at 207.
24. *Simon*, 694 F.3d at 207.
25. *Id.*

constructed system" and possibly grant the plaintiff "'greater relief than [he] could obtain from the Commission itself.'"[26]

The court, however, declined to hold that the filed rate doctrine always bars private antitrust suits challenging market-based rates, stating that it was "not announc[ing] a per se rule."[27] It acknowledged that the rationales of *Keogh* are not as relevant to cases in which regulators establish and oversee a market process rather than directly set rates.[28] The court also stated that "antitrust remedies become more necessary as markets become increasingly deregulated by the [market-based rate] system."[29]

### *B. United States v. Morgan Stanley*

In *United States v. Morgan Stanley*, the court approved a settlement between the Antitrust Division of the U.S. Department of Justice and Morgan Stanley, resolving an investigation of Morgan Stanley's alleged facilitation of an alleged illegal swap as a counterparty to an agreement between KeySpan and Astoria Generating Company Acquisition, L.L.C. (Astoria), two electricity generators operating in New York City.[30]

The Consent Decree "requir[ed] Morgan Stanley to disgorge to the United States Treasury $4.8 million in net revenues it earned from the transactions."[31] Pursuant to the Tunney Act, the Justice Department is required to obtain court approval of all consent decrees.[32] In response to a Competitive Impact Statement and proposed consent decree published in the *Federal Register*, as required by the Tunney Act, the Justice Department received formal comments objecting to the proposed consent decree from the New York Public Service Commission (NYPSC) and the AARP on three principal grounds: (1) the "$4.8 million in disgorgement [was] inadequate to deter future [wrongdoing]"; (2) Morgan Stanley [failed to] admit any wrongdoing"; and (3) the disgorged money should be [remitted] to New York City electricity customers," not the U.S. Treasury.[33]

The court rejected all three objections. First, the court found that the disgorgement, which amounted to "22% of Morgan Stanley's net revenues from the transactions" was a meaningful deterrent, observing that this case represented the "first attempt" by the Justice Department "to obtain disgorgement from a financial services firm [using derivatives] to facilitate anticompetitive [conduct]."[34] The court added that it "will not second-guess the wisdom of the [Justice Department's] decision to pursue a disgorgement remedy rather than restitution."[35] Second, in rejecting the commenters' objections to the failure of Morgan Stanley to admit liability, the court noted that "the Clayton Act and the

26. *Id.* (quoting Arkansas La. Gas Co. v. Hall, 453 U.S. 571, 579 (1981)).
27. *Id.* at 206.
28. *Id.*
29. *Id.*
30. United States v. Morgan Stanley, 881 F. Supp. 2d 563, 565-66, 569-70 (S.D.N.Y. 2012).
31. *Id.* at 566.
32. 15 U.S.C. § 16(b)-(c) (2012).
33. *Morgan Stanley*, 881 F. Supp. 2d at 566.
34. *Id.* at 567-68.
35. *Id.* at 568.

Tunney Act do not require an admission of [liability] as a prerequisite to [court] approval" of consent decrees.[36] Third, the court cited concerns that using disgorged funds to compensate New York City electricity customers could (1) violate the Miscellaneous Receipts Act, "which obligates Government officials receiving money for the Government from any source [to] deposit the money in the Treasury";[37] (2) "circumvent the filed rate doctrine;" and (3) incur transaction costs that are avoided by disgorgement to the United States Treasury.[38]

## II. ACQUISITIONS, DIVESTURES, AND MERGERS

### A. *Kinder Morgan's Acquisition of El Paso*

#### 1. Introduction

In October 2011, Kinder Morgan Inc. (Kinder Morgan) made a $21 billion bid for El Paso Corporation (El Paso).[39] Kinder Morgan operated 38,000 miles of pipelines and 180 terminals for natural gas, oil, refined petroleum products, and carbon dioxide in North America while El Paso operated 43,000 miles of natural gas pipeline and gathering assets.[40] The two firms displayed substantial horizontal overlaps at the time of the merger in relevant markets involving the mid-stream segment of their natural gas operations.[41]

On May 1, 2012, the Federal Trade Commission (FTC) issued a complaint finding that the proposed transaction would violate section 7 of the Clayton Act and section 5 of the Federal Trade Commission Act.[42] The FTC's Decision and Order, issued June 12, 2012, required Kinder Morgan to divest three natural gas pipelines, along with other conditions, to address the likely anticompetitive effects of the proposed transaction.[43] On November 9, 2012, the FTC approved the sale of the Kinder Morgan pipeline divestiture assets to Tallgrass Energy Partners LLC.[44]

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36. *Id.*

37. *Id.* at 569 (alteration in original) (quoting 31 U.S.C. § 3302(b) (2012)).

38. *Id.*

39. Michael J. De La Merced & Clifford Krauss, *Kinder Morgan to Buy El Paso for $21.1 Billion*, DEALBOOK.NYTIMES.COM (Oct. 16, 2011, 2:44 PM), http://dealbook.nytimes.com/2011/10/16/kinder-morgan-to-buy-el-paso/.

40. Analysis of Proposed Agreement Containing Consent Orders to Aid Public Comment at 1-2, *In re Kinder Morgan, Inc.*, FTC Docket No. C-4355 (May 1, 2012) [hereinafter Kinder Morgan Analysis], *available at* http://www.ftc.gov/os/caselist/1210014/120501kindermorgananal.pdf.

41. *Id.* at 2. Separate from the proposed acquisition, El Paso also anticipated selling its exploration and production assets. *Id.* at 1.

42. Complaint at 1, *In re Kinder Morgan, Inc*., FTC Docket No. C-4355 (May 1, 2012) [hereinafter Kinder Morgan Complaint], *available at* http://www.ftc.gov/os/caselist/1210014/120501kindermorgancmpt.pdf (citing Clayton Act § 7, 15 U.S.C. § 18, and Federal Trade Commission Act § 5, 15 U.S.C. § 45).

43. Decision and Order at 7, *In re Kinder Morgan, Inc.*, FTC Docket No. C-4355 (June 12, 2012) [hereinafter Kinder Morgan Decision and Order], *available at* http://www.ftc.gov/os/caselist/1210014/120614kindermorgando.pdf.

44. Letter from Donald S. Clark, Secretary, Fed. Trade Comm'n, to Laura A Wilkinson, Esq., Weil, Gotshal & Manges, LLP (Nov. 8, 2012), *available at* http://www.ftc.gov/os/caselist/1210014/121109kindermorganletter.pdf.

### 2. Jurisdiction and Past Natural Gas Pipeline Mergers

The FERC has the authority to regulate interstate natural gas pipeline transportation tariff prices and non-price terms of service. However, the FERC does not have the statutory authority to review mergers or acquisitions of interstate natural gas pipelines for the purposes of determining if the transaction is in the public interest.[45] Rather, "merger review is carried out primarily by the antitrust agencies. This role was decided in . . . *California v. Federal Power Commission*," which held that "the federal courts retained antitrust jurisdiction over natural gas mergers, a finding reinforced two years later in *United States v. El Paso Natural Gas*."[46]

The FTC has assumed the major role of reviewing the legality of natural gas pipeline mergers under section 7 of the Clayton Act and section 5 of the Federal Trade Commission Act. The agency has pursued a rigorous and consistent approach to evaluating the antitrust implications of pipeline transactions.[47] Remedies in past mergers have almost always been structural fixes, including the divestiture of pipelines, terminals, storage facilities, and other related assets.[48]

### 3. Antitrust Analysis

#### a. Relevant Markets

Overlaps between Kinder Morgan's and El Paso's natural gas pipeline transportation and processing assets in Wyoming, Colorado, and Utah set the stage for the FTC's competitive concerns regarding the acquisition.[49] Four Kinder Morgan pipelines and four El Paso pipelines were connected to natural gas production basins within this geographic area.[50] In evaluating whether the merger was likely to substantially lessen competition as a result of horizontal overlaps, the FTC defined a number of relevant markets.

Any pipeline market is typically defined around origin (i.e., supply) and destination (i.e., consumption). In this case, the FTC's complaint defines relevant markets as pipeline transportation of natural gas from wells in five production basins: (1) Denver/Julesburg/Niobrara, (2) Powder River, (3) Wind River, (4) Western Wyoming (including Green River, Red Desert, and Washakie), and (5) Piceance.[51]

The FTC identified a relevant destination market, defined as the transportation of natural gas by pipeline to utilities and other customers located in the Colorado Front Range. This market extends "from the Cheyenne Hub in Weld County, Colorado in the north to Pueblo, Colorado in the south."[52] The

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45. *What FERC Does*, FED. ENERGY REGULATORY COMM'N, http://www.ferc.gov/about/ferc-does.asp (last updated Feb. 3, 2012).

46. Diana L. Moss, *Natural Gas Pipelines: Can Merger Enforcement Preserve the Gains From Restructuring? in* COMPETITION POLICY AND MERGER ANALYSIS IN DEREGULATION AND NEWLY COMPETITIVE INDUSTRIES 39 (Edward Elgar ed., 2008) (citing California v. Fed. Power Comm'n, 369 U.S. 482, 487 (1962) and United States v. El Paso Natural Gas, 376 U.S. 651, 662 (1964)).

47. *Id.*

48. *Id.* at 41-42.

49. Kinder Morgan Complaint, *supra* note 42, at 5.

50. Kinder Morgan Analysis, *supra* note 40, at 2.

51. Kinder Morgan Complaint, *supra* note 42, at 2-4.

52. *Id.* at 4.

FTC's economic analysis notes that this consumption area "overlaps the Denver/Julesburg/Niobrara [p]roduction [b]asin."[53] To meet demand, however, "substantial additional natural gas from other production areas in the [Rocky Mountains]" is required, "particularly in the winter."[54]

The FTC defined two additional relevant markets. "No notice" natural gas delivery service is a premium product designed to accommodate consumers with fluctuating demands such that they cannot give notice to the pipeline. Rather than build expensive storage, utilities rely on interstate pipeline capacity and storage to meet quickly changing demand.[55] The FTC thus defined "no notice" gas delivery service to utility companies and local distribution companies in the Colorado Front Range region as a relevant market.[56] Since only Kinder Morgan and El Paso had facilities to remove natural gas liquids from unprocessed gas before injection into interstate pipelines, natural gas processing in the Wind River Basin was also a relevant market.[57]

b. Theory of Competitive Harm

The FTC's theory of competitive harm in Kinder Morgan-El Paso is not complicated. The Agency was concerned with eliminating anti-competitive direct and substantial existing horizontal competition that created high levels of post-merger concentration and merger-induced increases in concentration. These effects increased the likelihood that the merged firm could "exercise market power unilaterally."[58] That the FTC did not pursue a theory of coordinated effects—unlike some pipeline mergers—reflects the limited competition in the relevant markets affected by the proposed acquisition.

The FTC's economic analysis notes that eliminating competition between the two pipelines would lead "to higher prices for pipeline transportation [to shippers,] to the detriment of producers and consumers of natural gas."[59] The transaction "would [also] eliminate direct competition between [Kinder Morgan and El Paso] processing plants," raising "prices for gas processing[,] to the detriment of producers of natural gas."[60]

Finally, the Analysis explains that only pipelines that serve the Colorado Front Range areas can offer no-notice service.[61] While El Paso then offered no-notice service in the area, Kinder Morgan was likely a potential entrant into the market. The acquisition therefore "would eliminate potential competition for no-notice service[,] to the detriment of utility customers."[62] Moreover, "entry or expansion into relevant markets" was deemed unlikely by the FTC to "be timely,

53. Kinder Morgan Analysis, *supra* note 40, at 3.
54. *Id.*
55. *Id*.
56. Kinder Morgan Complaint, *supra* note 42, at 4.
57. *Id.* at 5.
58. *Id.*
59. Kinder Morgan Analysis, *supra* note 40, at 2.
60. *Id.* at 3.
61. *Id.*
62. *Id*. at 4.

likely, and sufficient in scope to [ameliorate] the harmful anticompetitive effects of the proposed acquisition."[63]

4. Remedy

Consistent with its preference for structural remedies to address competitive concerns in pipeline mergers, the FTC ordered the divestiture of: (1) Kinder Morgan's Rockies Express Pipeline LLC, Kinder Morgan Interstate Gas Transmission Pipeline LLC, and Trailblazer Pipeline Company LLC; and (2) two Kinder Morgan gas processing plants in the Rocky Mountain region, both within 180 days of the acquisition.[64]

Kinder Morgan was also required to provide transitional support, such as the licensing of important intellectual property (e.g., operations software) to the asset purchaser.[65] Finally, the FTC's Decision and Order held that buyers of the assets be allowed to recruit any Kinder Morgan employees engaged with the assets to be sold, and barred Kinder Morgan from attempting to rehire employees hired by the acquirer.[66] Standard compliance reporting and respondent's provision of access to records and information by FTC officials were also included in the Decision and Order.[67]

*B. Update on Duke-Progress Merger Since Last Year's Annual Report*

On June 8, 2012, the FERC issued an order accepting a proposed plan to mitigate the adverse competitive effects stemming from the proposed merger of Duke Energy Corp. and Progress Energy, Inc.[68] The applicants had been directed to submit the plan after the applicants' delivered price test indicated that the merger resulted in severe and systemic failures of the FERC's Competitive Analysis Screen in two markets in the Carolinas: the Duke Energy Carolinas, LLC (Duke Energy Carolinas) and the Carolina Power & Light (Progress Energy Carolinas-East) balancing authority areas.[69] The FERC had rejected an earlier proposal to offer certain quantities of energy from available generation into these markets at cost-based rates with oversight by an independent market monitor on the basis that the proposal did not mitigate the screen failures because, among other things, it did not cede control over the applicants' generation assets.[70]

Under the applicants' latest proposal, they agreed to increase import capability into these markets by constructing seven transmission expansion projects in the region with an estimated cost of approximately $110 million.[71] They further proposed to accelerate the in-service date of a previously planned 230 kV transmission line, which is necessary to support four of the proposed transmission expansion projects, from 2017 to 2015.[72] While the projects are

63. Kinder Morgan Complaint, *supra* note 42, at 5.

64. Kinder Morgan Analysis, *supra* note 40, at 1, 4.

65. *Id.* at 4.

66. Kinder Morgan Decision and Order, *supra* note 43, at 8-9.

67. *Id.* at 10.

68. *Duke Energy Corp.*, 139 F.E.R.C. ¶ 61,194 at PP 86-87 (2012) [hereinafter June 8 Order].

69. *Duke Energy Corp.*, 136 F.E.R.C. ¶ 61,245 (2011).

70. *Duke Energy Corp.*, 137 F.E.R.C. ¶ 61,210 at PP 80, 83, 89, 91-92 (2011).

71. June 8 Order, *supra* note 68, at P 25.

72. *Id.* at P 26.

being built, the applicants proposed to mitigate the screen failures identified by the FERC by making "firm sales of capacity and energy" under agreements with certain unaffiliated sellers.[73] Under these agreements, the buyers were required to take the full amount of energy provided for by each contract at a price tied to the price of natural gas reported at a particular trading hub, subject to *force majeure*, including cases of transmission unavailability.[74] The applicants explained that they had contracted with Potomac Economics to act as an independent market monitor and ensure that the agreements: (1) remain in effect while the transmission expansion projects are being built; or (2) are replaced by agreements with the same terms and conditions.[75]

The applicants maintained that the increase in import capability resulting from the transmission expansion projects would eliminate the failures identified by the FERC's market power screen in the Duke Energy Carolinas balancing authority area and would ultimately result in a market that is less concentrated than prior to the merger.[76] "With respect to the Progress Energy Carolinas-East [balancing authority area]," the applicants stated that the projects "would eliminate the screen failures identified by the [FERC]" except in one season.[77] The applicants argued that this isolated screen failure did not raise competitive concerns but that, if deemed necessary by the FERC, they would "establish a transmission set-aside of 25 MW of firm transmission capacity from the Duke Energy Carolinas [balancing authority area] to the Progress Energy Carolinas-East [balancing authority area]" following the completion of the transmission expansion projects, and that Potomac Economic would monitor compliance with the proposal.[78]

The FERC accepted the proposed permanent and interim mitigation measures with certain revisions and conditions. The FERC found that the "proposed [t]ransmission [e]xpansion [p]rojects [adequately] mitigated the screen failures identified" in its earlier order except in the one season noted by the applicants.[79] As far as this failure was concerned, the FERC noted that its previous Competitive Analysis Screen indicated that the failure of the screen was most severe in this period and, as a result, the FERC found that acceptance of the applicants' mitigation proposal for this period was warranted.[80] The FERC also conditioned its acceptance on a greater role for the independent monitor in assessing the applicants' progress in pursuing the construction of the transmission expansion projects, including a requirement that the monitor provide to the FERC progress reports every three months.[81] The FERC cautioned that it will require a further mitigation plan, including the possibility of asset divestiture, if the applicants fail to complete the projects as promised.[82]

73. *Id.* at P 36 (citation omitted).
74. *Id.* at P 37.
75. *Id.* at P 42.
76. June 8 Order, *supra* note 68, at P 28.
77. *Id.*
78. *Id.* at PP 29-31 (citation omitted).
79. *Id.* at P 87.
80. *Id.* at P 89.
81. June 8 Order, *supra* note 68, at P 91.
82. *Id.*

With respect to the interim mitigation measures, the FERC expressed concern about the fact that the agreements excused the buyers from purchasing energy if transmission service was unavailable. The FERC explained that "if the actual quantity of energy sold is less than the quantities of energy specified in the [agreements], [the applicants] would effectively retain control over the energy, and [that] market concentration levels [would] remain high."[83] To address this concern, the FERC imposed the following conditions: the applicants "cannot use control over their transmission systems to thwart sales" under the agreements and the independent monitor must report "any hours in which buyers do not purchase the full amount of energy" within three days; the applicants cannot have "any priority rights over other potential buyers to repurchase any of the energy and/or capacity sold"; and the applicants cannot "enter into transactions with the counterparties to the [agreements] except on a spot . . . basis."[84] Noting that there had been limited trades at the natural gas hub that the applicants proposed to base the price of energy on in the agreements, the FERC found that the applicants must either limit the price that they pay at that hub or replace that hub with a more liquid trading point.[85] Finally, the FERC required the applicants to post on their electronic board the amount of power that was sold under each agreement every time that they make such a sale and required the independent monitor to oversee the purchases made under the agreements on a daily, ongoing basis and to provide additional information about the transactions in its reports to the FERC.[86]

The FERC found that these conditions adequately mitigate the competitive impact of the merger. Accordingly, the FERC accepted the proposal and directed the applicants to submit a filing indicating whether they would accept these conditions.[87] Shortly thereafter, the applicants submitted a filing indicating that they would accept the conditions outlined in the June 8 Order[88] and the merger was consummated on July 2, 2012.[89] As of December 27, 2012, requests for rehearing of the June 8 Order were pending.[90]

### *C. Exelon-Constellation Merger*

#### 1. Maryland Public Service Commission Approval

In 2011, Exelon Corp. and Constellation Energy Group, Inc. proposed a merger that would have resulted in a single entity owning over 30,000 MW of generation in the PJM market, much of it concentrated in or near Maryland.[91]

83. *Id.* at P 102.

84. *Id.* at PP 103-04.

85. *Id.* at P 105.

86. June 8 Order, *supra* note 68, at PP 106-08.

87. *Id.* at P 113.

88. Duke Energy Corp., Form 8-K Filing with Sec. Exchange Comm'n (June 25, 2012), *available at* http://www.sec.gov/Archives/edgar/data/1326160/000110465912045578/a12-15330_18k.htm.

89. Press Release, Duke Energy, Duke Energy, Progress Energy Complete Merger (July 3, 2012), http://www.duke-energy.com/news/releases/2012070301.asp.

90. Order Granting Rehearing for Further Consideration, FERC Docket Nos. ER12-1338, et al. (Aug. 8, 2012).

91. *In re* Exelon Corp., 295 P.U.R.4th 183, 2012 WL 833884, at *5, *10, *19 (Md. P.S.C. Feb. 17, 2012).

On February 17, 2012, the Maryland Public Service Commission (MPSC) issued an order conditionally approving the merger.[92] The applicants had volunteered plant divestitures and behavioral commitments to mitigate concerns over increased market power in PJM. The MPSC deemed all of those measures to be necessary, and it added more measures of its own as conditions of its approval.[93]

Parties to the proceedings analyzed the market power issues under FERC market power screens as well as under other approaches. The MPSC ruled that it was not bound to follow the FERC's tests and instead examined "all credible evidence related to market power."[94] The MPSC found that market power concerns were significant, and not "minor" as characterized by the applicants' expert. The MPSC cited evidence that increased concentration in eastern PJM capacity markets exceeded the thresholds in FERC market power screens by as much as 238 points (exceeding the 100-point FERC threshold for unacceptable market power), and that market power in those markets was "endemic" according to the PJM Independent Market Monitor (IMM).[95]

The applicants' voluntary mitigation measures were developed in several stages. In their initial application, they offered to divest three coal plants with a combined capacity of 2,648 MW, and to "contractually divest" 500 MW of energy by entering into fixed price power sales of that amount for periods of one year or longer.[96] They also committed to bid all uncommitted capacity into PJM capacity markets at or below PJM- approved price caps.[97]

During the MPSC proceeding, the applicants reached an agreement to address the IMM's continuing market power concerns by ensuring that the divested coal plants would not be sold to an entity with a 3% or greater share of the PJM capacity market, and by accepting limitations on their right to retire capacity. They also agreed to offer all peaking capacity into PJM energy markets at capped prices, and to continue bidding ancillary services into the market.[98]

Finally, during the briefing stage, the applicants agreed with several intervenors to develop 285 to 300 MW of new capacity in Maryland, including 165 MW of solar, animal waste, and other renewable resources to offset the risk that other plants would be retired. This would reduce the risk of harm to consumers by increasing the amount of capacity that the applicants would have to withhold from the market to drive up prices.[99] The applicants also agreed to MPSC authority to enforce their agreement with the IMM.[100]

To protect consumers from "immediate harm," the MPSC said that it would condition its merger approval on the applicants' acceptance of *all* of the measures, and would also require (i) that it be accorded authority to approve any change to the IMM agreement, and (ii) that it have the authority to extend that

92. *Id.* at *1.
93. *Id.* at *1-3.
94. *Id.* at *29.
95. *Id.*
96. *Exelon Corp.*, 2012 WL 833884, at *20.
97. *Id.* at *21.
98. *Id.* at *25.
99. *Id.* at *26-27.
100. *Id.* at *58.

agreement beyond its stated ten-year term if market power concerns remained.[101] With several additional conditions unrelated to market power issues, the MPSC approved the merger.[102]

2. New York Public Service Commission Approval

On December 20, 2011, the New York Public Service Commission (NYPSC) issued an order allowing the merger to move forward without conditions.[103] The NYPSC examined competitive issues from two perspectives, first from within New York itself, and second, from the perspective of spillover effects into New York of the merging parties' enhanced market share in adjoining portions of the PJM market. The NYPSC found that the proposed merger created no "potential for the exercise [of] horizontal market power within New York" because Exelon owned no generation in the state prior to the merger, and it was acquiring only the 4.8% share of that market that Constellation indirectly owned through its control of 50.01% of the Nine Mile Point and Ginna nuclear plants.[104]

The situation in PJM was more complicated. In what the NYPSC called "the PJM Classic market," consisting of the subset of the overall PJM market adjacent to New York, the merger would give the combined companies a 21.3% market share, which the NYPSC said would "create the potential for the exercise of horizontal market power."[105]

Because the New York and PJM Classic markets are interconnected, the NYPSC concluded that higher prices resulting from the exercise of market power in the latter could, in theory, spill over into the former.[106] However, the NYPSC determined that this possibility was remote and did not warrant a more in-depth examination of competitive effects, because: (1) the two markets are managed separately by two independent operators, creating impediments at the boundaries of the markets; (2) physical constraints on interties between the markets limited imports into the New York Independent System Operator, Inc. (NYISO) to 10% of the generation capacity in that market; (3) constraints within PJM itself further restricted the transmission of electricity from units owned by Exelon into the NYISO; and (4) review of the merger by federal and Maryland state authorities was likely to result in measures mitigating any market power in PJM.[107]

The NYPSC determined that there was insufficient evidence of the likelihood of competitive harm to overcome the presumption in its existing policy that mergers involving upstream "owners of New York generat[ing] facilities need not be reviewed [since] the operation of competitive markets, or market mitigation measures that align prices with competitive market outcomes,

101. *Exelon Corp.*, 2012 WL 833884, at *28, *30.

102. *Id.* at *35-48.

103. *Exelon Corp.*, Case No. 11-E-0245, *Declaratory Ruling on Review of a Stock Transfer Transaction*, slip op. at 10-11 (N.Y.P.S.C. Dec. 20, 2011).

104. *Id.* at 1, 11.

105. *Id.*

106. *Id.* at 12.

107. *Id.* at 12-14.

sufficiently protect ratepayers from the exercise of market power."[108] The NYPSC found that the merger did not raise vertical market power concerns, because the merging parties did not exercise control over electric delivery facilities or substantial influence over generation inputs such as fuel; and because the NYPSC retained authority to oversee Constellation's affiliations with power marketers.[109]

3. Federal Energy Regulatory Commission Approval

On March 9, 2012, the FERC issued an order (Merger Order) conditionally approving the merger of Exelon and Constellation.[110] Together, the applicants owned or controlled over 30,000 MW of generation in PJM. While the FERC found that the merger raised horizontal market power concerns in certain PJM submarkets as well as in PJM as a whole, it concluded that those concerns were adequately addressed by generation divestitures and other mitigation measures, most of which the applicants had agreed to in their application and in an agreement with the IMM.[111]

In their initial FERC filing, Exelon and Constellation had identified the relevant product markets for analysis of effects on horizontal market power "as energy, capacity and ancillary services."[112] The relevant ancillary services were "energy imbalance, regulation, synchronized reserve and supplemental reserves."[113]

The applicants specified different geographic markets for each of these products. For energy, they examined the effect of the merger on competition in PJM as a whole, as well as in three geographic submarkets denominated PJM East, AP South, and 5004/5005.[114] They identified these submarkets as the areas in which "prices can diverge due to internal transmission constraints."[115] The FERC agreed with the applicants' position on relevant geographic markets for energy, noting that while it had not previously recognized AP South and 5004/5005 as submarkets, "the frequency of binding constraints on the relevant interfaces that create price separation within PJM lead us to conclude that those markets should be considered separate relevant submarkets."[116] It rejected the Illinois Attorney General's (AG) argument to add Northern Illinois as a relevant submarket, finding that the Illinois AG incorrectly "attribute[d] all energy purchased in [PJM] to two suppliers" and failed to "separate purchases by season or load."[117]

108. *Id.* at 13-14.

109. *Id.* at 14.

110. *Exelon Corp.*, 138 F.E.R.C. ¶ 61,167 at P 2 (2012).

111. *Id.* at PP 49, 93.

112. *Id.* at P 24.

113. *Id.* at P 46.

114. *Id.* at P 26. AP South comprised transmission zones of utilities in New Jersey, Delaware, DC, Virginia and Eastern Pennsylvania. 5004/5005 derived its name from two constrained transmission lines, and overlapped with AP South, with the exception of the transmission zone of a Virginia utility. *Id.* at P 26 nn.19, 20.

115. 138 F.E.R.C. ¶ 61,167, at P 26.

116. *Id.* at P 31.

117. *Id.* at P 33.

For capacity, the applicants identified the relevant geographic markets as the PJM-wide Reliability Pricing Model (RPM) market and two Locational Deliverability Area (LDA) submarkets, the Mid-Atlantic Area Council (MAAC) and the Eastern Mid-Atlantic Area Council (EMAAC).[118] They stated that "ancillary services markets are essentially RTO-wide markets."[119] The Merger Order does not indicate that any other party argued for different or additional geographic markets for these products.

FERC regulations require merger applicants to analyze increases in market shares, as measured by the Herfindahl-Hirschman Index (HHI) that would result in each of the relevant markets "where there is more than a *de minimis* overlap."[120] The applicants supplied this analysis for ten different seasonal on-peak, shoulder, and off-peak time periods.[121] Their analysis showed unacceptable market share increases for energy and capacity (but not for ancillary services) in each of the relevant geographic markets and submarkets.[122] The FERC accepted their analysis.[123]

Exelon and Constellation initially proposed to mitigate these increases through plant divestitures, fixed price power sales contracts, and commitments to bid all uncommitted capacity into capacity markets at capped prices.[124] In addition, they proposed to accept price caps on energy, capacity, and ancillary services provided by the plants to be divested as interim measures until the divestitures were consummated.[125]

Several parties challenged the adequacy of the applicants' mitigation commitments and supporting analysis. Maryland and Pennsylvania (MD/PA) consumer advocates argued that: (i) the applicants "failed to analyze the ability of the combined company to influence market prices based on the specific plants it will own";[126] (ii) the applicants' proposal to mitigate market power through a fixed price power sales contract would not prevent the exercise of market power; (iii) plant divestitures might simply transfer the increase in market power to other entities; (iv) the applicants' own studies showed unacceptable increases in a capacity submarket even after mitigation; and (v) the applicants' attempt to excuse certain increases in market concentration by pointing to the potential for new market entry was unpersuasive.[127] They proposed limiting buyers of divested facilities to entities with small market shares and that the applicants be required to divest an additional 637 MW of generating capacity.[128]

The IMM contended that the competitive issues "could be addressed by an effective mitigation plan."[129] It agreed with the MD/PA consumer advocates that there should be restrictions on what entities could acquire the divested

118. *Id.* at PP 44-45.
119. *Id.* at P 46.
120. *Id.* at P 34 (citing 18 C.F.R. § 33.1 (2011)).
121. 138 F.E.R.C. ¶ 61,167, at P 34.
122. *Id.* at PP 36, 38, 40, 42, 46.
123. *Id.* at P 49.
124. *Id.* at PP 51-53.
125. *Id.* at PP 54-57.
126. 138 F.E.R.C. ¶ 61,167, at P 63.
127. *Id.* at PP 64-67.
128. *Id.* at P 68.
129. *Id.* at P 69.

plants, and it recommended additional divestiture-related conditions.[130] The American Public Power Association (APPA) asked the FERC to undertake a more detailed analysis of potential anticompetitive effects, adding that PJM's capacity market was inherently flawed.[131]

In October 2011, Exelon and Constellation entered into an agreement with the IMM to undertake additional mitigation measures, including commitments not to sell any plants to eight specifically identified entities; to calculate bidding caps using the most current available data; not to retire or uprate units unless specific conditions were met; and to abide by other restrictions with respect to offers from specified plants.[132]

The FERC found that the merger, "as mitigated and conditioned, [would] not harm competition in the relevant . . . markets."[133] It relied in part on the mitigation measures proposed by the applicants, as supplemented in their agreement with the IMM. The FERC added the additional condition that the applicants "appoint an independent entity . . . to certify that [they] have complied with the interim mitigation conditions."[134]

The FERC also agreed with the intervenor, American Antitrust Institute (AAI), that the FERC should analyze the competitive effects of the merger under the terms of its own regulations, and not rely exclusively on the analysis of the IMM, which applied slightly different criteria.[135] The FERC set forth its own analysis in the Merger Order and reaffirmed, based on that analysis, that the mitigation measures were adequate.[136]

The FERC also found that the merger would not adversely affect vertical market power in gas markets because the merged entity would "only control a relatively small amount of natural gas deliverable capacity and storage capacity"; and it was unconcerned about electricity markets both because "[a]pplicants' transmission facilities will continue to be under the operational control of PJM," and because there were no other significant barriers to entry.[137]

4. Department of Justice Approval

On December 21, 2011, the United States Department of Justice (DOJ) filed a complaint alleging that the proposed merger between Exelon and Constellation would substantially lessen competition in the provision of wholesale electricity, in violation of section 7 of the Clayton Act.[138] Simultaneous with that filing, the DOJ filed a proposed Final Judgment reflecting a stipulation by Exelon and Constellation to divest generating plants at three locations.[139] These were the

130. *Id.*

131. 138 F.E.R.C. ¶ 61,167, at PP 70-72.

132. *Id.* at PP 82-85.

133. *Id.* at P 93.

134. *Id.* at P 103.

135. *Id.* at P 95.

136. 138 F.E.R.C. ¶ 61,167, at P 97.

137. *Id.* at P 113.

138. Complaint at 11, United States v. Exelon Corp., 2012 WL 3018030 (D.D.C. May 23, 2012) (No. 1:11-cv-02276), 2011 WL 6401170; 15 U.S.C. § 18.

139. United States v. Exelon Corp., No. 1:11-cv-02276, 2012 WL 3018030, at *1 (D.D.C. May 23, 2012) (the three plants were the Brandon Shores Power Plant, the H.A. Wagner Power Plant, and the CP Crane Power Plant, all in Baltimore, MD).

same plants that Exelon and Constellation agreed to divest in their application for FERC approval in order to mitigate horizontal market power concerns.

On May 23, 2012, the United States District Court for the District of Columbia approved the Final Judgment as proposed by the DOJ.[140]

## III. PROPOSED POLICY STATEMENT OF CAPACITY ON NEW MERCHANT TRANSMISSION PROJECTS AND NEW COST BASED, PARTICIPANT-FUNDED TRANSMISSION PROJECTS

On July 19, 2012, the FERC issued a proposed policy statement on allocating "capacity for new merchant transmission projects and new non-incumbent, cost-based, participant-funded transmission projects."[141] In the Policy Statement, the FERC proposes to allow developers to allocate 100% of the transmission capacity of their projects through bilateral negotiation.[142] The FERC's objective is to ensure continued transparency in the capacity allocation process and prevent undue discrimination in the capacity allocation process while affording developers the flexibility to negotiate bilaterally for the full amount of transmission capacity.[143] Developers would no longer be required to offer all customers the same terms and conditions in a rigid open season process. Rather, non-incumbent transmission developers would have flexibility during the capacity allocation process to negotiate important terms and conditions on a bilateral basis with individual anchor tenants, thereby providing developers the ability to address their unique needs and those of their potential customers.[144]

In the Policy Statement, the FERC proposes to streamline its capacity allocation policies, which have evolved through numerous petitions for declaratory orders that merchant and nontraditional transmission developers have filed. Currently, the FERC evaluates merchant transmission based on a four-factor analysis developed in *Chinook Power Transmission, LLC* (*Chinook*): "(1) the justness and reasonableness of rates; (2) the potential for undue discrimination; (3) the potential for undue preference, including affiliate preference; and (4) regional reliability and operational efficiency requirements."[145] Under the *Chinook* analysis, the FERC relies upon an open season for the initial allocation of transmission capacity and a post-open season report to ensure transparency and prevent undue discrimination.[146] In *Chinook*, the FERC permitted "developers to allocate some portion of capacity through anchor customer presubscriptions, while requiring that the remaining portion be allocated in a subsequent open season."[147] Since *Chinook*, the FERC has ruled on several similar proposals, including a request to allocate "up to [75%] of a

140. *Id.* at *1-2.

141. Proposed Policy Statement, *Allocation of Capacity on New Merchant Transmission Projects and New Cost-Based, Participant-Funded Transmission Projects, Priority Rights to New Participant-Funded Transmission*, 140 F.E.R.C. ¶ 61,061 at P 1 (2012) [hereinafter Policy Statement].

142. *Id.* at P 12.

143. *Id.* at PP 2, 10.

144. *Id.* at P 18.

145. *Chinook Power Transmission, LLC*, 126 F.E.R.C. ¶ 61,134 at P 37 (2009).

146. Policy Statement, *supra* note 141, at P 5.

147. *Id.*

transmission project's capacity to anchor customers."[148] The FERC has permitted participant funding of transmission projects by both incumbent and non-incumbent transmission developers; however, in the Policy Statement the FERC distinguishes between incumbent and non-incumbent developers and does not propose to permit the latter to allocate transmission capacity on a purely bilateral basis.[149]

In the Policy Statement, the FERC states that bilateral negotiation is an "appropriate vehicle for new merchant transmission projects and new non-incumbent, cost-based, participant-funded transmission projects."[150] While the FERC intends that *Order No. 1000*[151] will ensure that transmission needs are identified and addressed through the regional transmission planning process, the FERC recognizes the importance of merchant transmission and cost-based participant-funded transmission projects and the critical role that bilateral negotiations play in providing flexibility for the development of those projects.[152] Accordingly, the Policy Statement would serve as a "roadmap" for developers to pursue projects that, although not ultimately selected in a regional plan for purposes of cost allocation, warrant bilateral negotiations with potential customers.[153]

Under the Policy Statement, developers of such projects will be permitted "to select a subset of customers, based on not unduly discriminatory or preferential criteria, and negotiate directly" with them regarding key terms and conditions when the developers "broadly solicit interest in the project from potential customers, and submit a report to [the FERC] describing the solicitation, selection, and negotiation process."[154] If developers satisfy these two requirements, they may "allocate up to 100[%] of their projects' capacity through bilateral negotiations."[155] The FERC proposes to permit capacity to be allocated to affiliates, but developers must seek FERC approval if an affiliate is to be a customer.[156]

To satisfy the requirement of an open solicitation, the FERC proposes to require developers to issue notice "in a manner that ensures that all potential and interested customers are informed of the proposed project."[157] The notice should include transmission developer points of contact and relevant project dates, and provide technical specifications and contract information including: (1) project size/capacity, (2) end points of the line, (3) projected construction and/or in-service dates, (4) type of line (i.e., DC, AC, bi-directional), (5) a precedent

148. *Id.*

149. *Id.* at P 6.

150. *Id.* at P 10.

151. Order No. 1000, *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, F.E.R.C. STATS. & REGS. ¶ 31,323 (2011), 76 Fed. Reg. 49,842 (Aug. 11, 2011), 136 F.E.R.C. ¶ 61,051 (July 21, 2011), *order on reh'g and clarification*, Order No. 1000-A, 77 Fed. Reg. 32,184 (May 31, 2012), 139 F.E.R.C. ¶ 61,132 (May 17, 2012), *review docketed sub nom.* S.C. Pub. Serv. Auth. v. FERC, No. 12-1232 (D.C. Cir. filed May 25, 2012).

152. Policy Statement, *supra* note 141, at P 10.

153. *Id.*

154. *Id.* at P 2.

155. *Id.* at P 12.

156. *Id.* at P 23.

157. Policy Statement, *supra* note 141, at P 15.

agreement (if developed), and (6) other capacity allocation arrangements.[158] The notice would also specify the criteria for the selection of transmission customers.[159]

To prevent undue discrimination, the FERC proposes to require developers to submit a report detailing the open solicitation process. The report envisioned must be submitted "shortly after" the open solicitation and resulting negotiations.[160] The report must describe "the processes that led to the identification of transmission customers" and subsequent contract execution, "the criteria used to select customers, any price terms, and any risk-sharing terms and conditions that served as the basis for identifying transmission customers" that were selected as against those that were not.[161]

Although the FERC proposes to apply the proposed framework to both merchant transmission projects and non-incumbent, cost-based, participant-funded transmission projects, the Policy Statement retains the distinction between them.[162] While the negotiations between developers and customers could in each case address transmission rates, the FERC's approach to reviewing those rates for merchant and non-incumbent participant-funded transmission developers would remain different. Merchant transmission developers would continue to need to satisfy the four-factor analysis described in *Chinook* for negotiated rates; however, by following the Policy Statement, merchant transmission "developer[s] would be deemed to have satisfied the second (undue discrimination) and third (undue preference) factors of the [*Chinook*] analysis."[163] The FERC will review proposed cost-based rates (including an agreed upon return on equity) for non-incumbent, cost-based, participant-funded transmission projects and will rely upon the criteria proposed in the Policy Statement only to address concerns regarding undue discrimination or preference regarding capacity allocation. Such projects will not be evaluated based on the other aspects of the *Chinook* analysis.[164]

Finally, the FERC proposes not to apply the Policy Statement to evaluate requests for cost-based participant-funded projects submitted by incumbent transmission owners.[165] Rather, the FERC will continue to evaluate such proposals on a case-by-case basis. Unlike non-incumbent developers, incumbent transmission owners have a clearly defined set of obligations under their OATTs. The FERC explains that it would expect that in most cases incumbent transmission owners "will be able to use existing processes set forth in [their OATTs] to allocate capacity on a new transmission facility."[166]

Eighteen sets of comments on the Policy Statement were filed, with the majority of comments noting support for the FERC's proposed policy for allocation of capacity on merchant transmission and cost-based, participant-

158. *Id.*
159. *Id.* at P 16.
160. *Id.* at P 21.
161. *Id.*
162. Policy Statement, *supra* note 141, at PP 24-25.
163. *Id.* at P 12 n.29.
164. *Id.* at P 26.
165. *Id.* at P 27.
166. *Id.*

funded transmission. Several merchant and non-incumbent transmission developers applauded the FERC for proposing reforms that will promote the development of transmission projects by making it easier for developers to respond to unique financing challenges and secure financing to construct transmission projects.[167] However, developers also expressed concerns regarding the confidentiality of reports submitted to describe the open solicitation process.[168] Although acknowledging the need for transparency, the developers were also concerned that the reports on the open solicitation process may include commercially sensitive information or critical energy infrastructure information.[169] The AAI noted concerns that the post-open solicitation reporting requirement could potentially facilitate anticompetitive, collusive behavior among market participants.[170]

Four commenters opposed the adoption of the Policy Statement.[171] Those opposing the Policy Statement expressed concerns that the Policy Statement would frustrate non-discriminatory open access to transmission by providing the incentive and opportunity to discriminate in favor of anchor customers.[172] The APPA also explained that *post hoc* reporting requirements following the open solicitation process do not provide sufficient transparency and will not operate as a deterrent to undue discrimination,[173] especially if developers are permitted to "water down" their reports through requests for confidential treatment.[174] Commenters argued that the section 206 complaint process under the Federal Power Act would be insufficient to protect against undue discrimination by transmission developers because complainants would have the burden of proof.[175] The NJ Rate Counsel recommended placing an affirmative burden on transmission developers to demonstrate that their open solicitation process resulted in a capacity allocation that is not unduly discriminatory.[176] NRECA expressed concerns about permitting merchant transmission development outside

167. Supporting commentors for *Allocation of Capacity on New Merchant Transmission Projects and New Cost-Based, Participant-Funded Transmission Projects, Priority Rights to New Participant-Funded Transmission*, were LSP Transmission Holdings, LLC, Transmission Developers, Inc., TransWest Express LLC, American Electric Power Service Corporation [hereinafter AEP Comments], and Pattern Transmission LP [hereinafter Pattern Transmission Comments]. These comments are available via the FERC's eLibrary by typing "AD12-9" into the docket number query in a general search.

168. *See, e.g.*, AEP Comments, *supra* note 167, at 4; Pattern Transmission Comments, *supra* note 169, at 13-14. *See also* Comments of Edison Electric Institute at 6, *Allocation of Capacity on New Merchant Transmission Projects and New Cost-Based, Participant-Funded Transmission Projects, Priority Rights to New Participant-Funded Transmission*, FERC Docket Nos. AD12-9-000, et al. (filed Sept. 24, 2012).

169. *See, e.g.*, AEP Comments, *supra* note 167, at 5.

170. Comments of the American Antitrust Institute at 10-11, *Allocation of Capacity on New Merchant Transmission Projects and New Cost-Based, Participant-Funded Transmission Projects, Priority Rights to New Participant-Funded Transmission*, Docket Nos. AD12-9-000, et al. (filed Sept. 24, 2012).

171. Opposing commenters included the American Public Power Association [hereinafter APPA comments], the Transmission Access Policy Study Group [hereinafter TAPS Comments], the National Rural Electric Cooperative Association [hereinafter NRECA Comments], and the New Jersey Division of Rate Counsel [hereinafter NJ Rate Counsel Comments]. These comments are available via the FERC's eLibrary by typing "AD12-9" into the docket number query in a general search.

172. TAPS Comments, *supra* note 171, at 5-9; APPA Comments, *supra* note 171, at 8-9.

173. APPA Comments, *supra* note 171, at 5-6.

174. *Id.* at 7.

175. NRECA Comments, *supra* note 171, at 14-15; NJ Rate Counsel Comments, *supra* note 171, at 9-11.

176. NJ Rate Counsel Comments, *supra* note 171, at 10.

of regional planning processes and the risk that merchant transmission projects would compete for rights-of-way with other regionally planned transmission projects and potentially lead to increased costs for load-serving entities and ratepayers.[177] The FERC has not yet issued a final policy statement to respond to these concerns.

## IV. ANALYSIS OF HORIZONTAL MARKET POWER UNDER THE FEDERAL POWER ACT: ORDER REAFFIRMING POLICY AND TERMINATING PROCEEDING

### *A. Introduction*

On February 16, 2012, the FERC issued an order retaining its existing approach to analyzing market power for merger and market-based rate applications.[178] The order followed a March 17, 2011 Notice of Inquiry (NOI),[179] which was prompted by revisions to the Horizontal Merger Guidelines issued by the DOJ and the FTC on August 19, 2010 (2010 HMG).[180] The 2010 HMG replaced guidelines issued by the DOJ and the FTC in 1992 (1992 HMG),[181] on which current FERC merger policy is based. In its NOI, FERC sought comment on five topics:

> (1) whether [it] should adopt the approach of the 2010 [HMG], placing 'less emphasis on market definition and the use of prescribed formula' for assessing a merger's competitive effects; (2) whether [it] should adopt the revised HHI levels of the 2010 [HMG] to screen mergers; (3) whether [it] should adopt any other elements of the 2010 [HMG]; (4) whether process differences between [it] and the [DOJ and FTC] affect . . . the FERC['s adoption of] the 2010 [HMG]; and (5) whether the 2010 [HMG] should have an effect on the FERC's market power analysis in its electric market-based rate program.[182]

Upon review of the seventeen comments that were submitted,[183] the FERC issued the order and terminated the proceeding in the associated docket.[184]

### *B. Merger Policy Issues*

In its 1996 Merger Policy Statement (MPS), the FERC adopted the five-step framework of the 1992 HMG to evaluate the competitive effects of

177. NRECA Comments, *supra* note 171, at 10-11.

178. Order Reaffirming Commission Policy and Terminating Proceeding, *Analysis of Market Power Under the Federal Power Act*, 138 F.E.R.C. ¶ 61,109 (2012) [hereinafter February 16 Order]. Under section 203 of the FPA, Commission authorization is required for public utility mergers. 16 U.S.C. § 824b (2012).

179. Notice of Inquiry, *Analysis of Horizontal Market Power Under the Federal Power Act*, F.E.R.C. STATS. & REGS. ¶ 35,571 (2011), 76 Fed. Reg. 16,394 (Mar. 23, 2011) [hereinafter NOI].

180. U.S. DEP'T OF JUSTICE & FED. TRADE COMM'N, HORIZONTAL MERGER GUIDELINES (2010), *available at* http://www.ftc.gov/os/2010/08/100819hmg.pdf.

181. U.S. DEP'T OF JUSTICE & FED. TRADE COMM'N, HORIZONTAL MERGER GUIDELINES (1992, *rev'd* 1997), *available at* http://www.ftc.gov/bc/docs/horizmer.shtm. The Competition and Antitrust Committee's 2011 Report discussed differences between the 1992 and 2010 HMG. *Report of the Competition & Antitrust Committee*, 32 ENERGY L.J. 159, 168-71 (2011).

182. *Report of the Competition & Antitrust Committee*, 33 ENERGY L.J. 159, 178 (2012) (quoting NOI, *supra* note 179, at P 13).

183. February 16 Order, *supra* note 178, at P 1. The Competition and Antitrust Committee's 2011 Report discussed the NOI and submitted comments. *Report of the Competition & Antitrust Committee*, 33 ENERGY L.J. 159, 177-82 (2012).

184. February 16 Order, *supra* note 178, at P 2.

proposed electric utility mergers.[185] The five steps involve evaluating: (1) concentration in a relevant market; (2) concerns about adverse competitive effects; (3) whether entry would offset or counteract competitive effects; (4) whether the transaction would result in efficiencies; and (5) whether either party to the transaction would fail absent the transaction.[186] To evaluate concentration and identify mergers that clearly do not raise competitive concerns, the FERC adopted a market concentration screen based on the HHI thresholds of 1992 HMG, which is referred to as the Competitive Analysis Screen (CAS) and is described in Appendix A of the MPS.[187]

The NOI identified key features of the 2010 HMG. In particular, the FERC noted that the 2010 HMG modified the HHI thresholds of the 1992 HMG used to classify market concentration and assess a merger's competitive concerns.[188] The FERC explained that relative to the 1992 HMG, "the 2010 [HMG] deemphasize[d] market definition as a starting point" for assessing competitive effects; instead, the 2010 HMG call for a fact-intensive inquiry, using a range of analytical tools, to assess competitive effects.[189] The FERC also noted that the 2010 HMG address the competitive effects of partial acquisitions and minority ownership.[190] Despite the differences between the 1992 HMG and the 2010 HMG, in its Order, the FERC declined to alter its existing merger policy, which remains largely based on the 1992 HMG.

First, the FERC declined to adopt the approach of the 2010 HMG, choosing to retain its existing five-step framework, based on the 1992 HMG, for assessing a transaction's competitive effects.[191] The FERC stated that the five-step framework "remains useful in determining whether a merger will have an adverse impact on competition."[192] In response to comments that the FERC is "overly rigid" in its application of the CAS, the FERC stated that its "current approach is flexible enough to incorporate theories set forth in the 2010 [HMG], while still retaining the certainty that the current approach provides."[193]

Second, the FERC declined to adopt the 2010 HHI thresholds for use in the CAS.[194] The FERC stated that the more stringent thresholds of the 1992 HMG are appropriate given the distinctive characteristics of electricity markets.[195] The FERC also stated that it would be inappropriate to adopt the HHI thresholds of the 2010 HMG without adopting other aspects of the 2010 HMG because it "could undermine the Commission's ability to accurately assess the competitive effects of a merger."[196]

Finally, the FERC declined to adopt any other elements of the 2010 HMG, including the "analysis of partial acquisitions and minority ownership" set out in

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185. *Id.* at P 4.
186. *Id.* at P 4 n.8.
187. *Id.* at P 4.
188. *Id.* at P 8.
189. February 16 Order, *supra* note 178, at P 9.
190. *Id.*
191. *Id.* at P 34.
192. *Id.*
193. *Id.* at P 36.
194. February 16 Order, *supra* note 178, at P 39.
195. *Id.*
196. *Id.*

the 2010 HMG, stating that its current approach is not contrary to the 2010 HMG.[197] The FERC also declined to adopt the analysis of monopsony power set out in the 2010 HMG, noting that its current policy allows for the evaluation of monopsony power, and that the FERC would "continue to consider the issue of buyer market power on a case-by-case basis."[198]

### *C. Market-Based Rate Issues*

"The [FERC] allows sales of electric energy, capacity, and ancillary services at market-based rates if the applicant . . . do[es] not have . . . market power."[199] The FERC has adopted two indicative screens, a market share screen (20% of the relevant market) and "a pivotal supplier screen to identify sellers that raise no horizontal market power concerns and can otherwise be considered for market-based rate authority."[200] "Failing either screen creates a rebuttable presumption that the seller has horizontal market power."[201] If a seller passes both the market share screen and the pivotal supplier screen, "there is a rebuttable presumption that it does not possess horizontal market power."[202] If a seller passes both screens and the HHI is less than 2,500 in the relevant markets, that constitutes "a showing of a lack of market power, absent compelling contrary evidence from intervenors."[203]

In its Order, the FERC declined to modify its current market power analysis for electric market-based rate applications to reflect the 2010 HMG.[204] The FERC stated that "its market-based rate analysis is not explicitly tied to the [1992 HMG]" and that "commenters fail[ed] to identify any feature [in the] guidelines that warrant a change."[205] The FERC rejected arguments that it should increase the existing market share screen threshold. The FERC stated that a conservative approach is appropriate because a firm with a 20% share is not likely to be an insignificant factor in the market, and market power is more likely to be present in electricity markets at low shares because of a low elasticity demand.[206] Moreover, the FERC noted that the HHI threshold it uses as part of a showing of a lack of market power (2,500) is consistent with the thresholds of the 2010 HMG.[207]

## V. ASTORIA PLANT ICAP MARKET MANIPULATION

### *A. Introduction*

In *Astoria Generating Company L.P. v. New York Independent System Operator, Inc.*, the FERC addressed allegations of potential price suppression in

197. *Id.* at P 41.
198. *Id.* at P 42.
199. February 16 Order, *supra* note 178, at P 6.
200. *Id.*
201. *Id.*
202. *Id.*
203. *Id.* at P 7.
204. February 16 Order, *supra* note 178, at P 55.
205. *Id.*
206. *Id.* at P 56.
207. *Id.* at P 55.

the New York City (NYC) installed capacity (ICAP) market of the NYISO.[208] According to the Complainants,[209] the "NYISO improperly implemented its buyer-side market power mitigation provisions" in violation of its "Market Administration and Control Area Services Tariff (Services Tariff)" which could result in "uneconomic entry in the NYC [ICAP] market."[210] The FERC granted in part and denied in part the Complaint.[211]

### *B. Transparency in NYISO's Implementation of Buyer-Side Mitigation Rules*

The Complainants alleged the NYISO's approach to buyer-side mitigation "is inconsistent with the Commission's long held principles that competitive markets benefit from greater transparency wherever possible and that market participants have a right to understand how [the NYISO] will apply its tariffs, including its mitigation measures."[212] The Complainants asserted that "[t]he fact that the Services Tariff contains only limited detail as to how the NYISO is to calculate Offer Floors and make Mitigation Exemption Test determinations does not mean that the NYISO enjoys unfettered discretion to do whatever it pleases" but instead "NYISO is bound to make these determinations in a manner that is consistent with what market participants would reasonably expect in light of the plain English meanings of the terms used in the Services Tariff."[213]

The FERC found that the "NYISO's actions were adequate to meet the requirements of [its] tariff."[214] The FERC explained that it "has recognized that the goal of transparency must be balanced against other goals, such as the protection of commercially sensitive information and administrative efficiency" and found that the "NYISO has properly treated information it is required to keep confidential, i.e., commercially sensitive and proprietary data, as the improper release of this information could cause harm to the individual ICAP suppliers and to a competitive market."[215] But the FERC "agree[d] with Complainants that developers would benefit from examples of how the mitigation and offer floor rules will be applied because increased clarity and a better understanding of how the rules will be applied benefit both new entrants and existing market participants" and directed the "NYISO to provide examples on its website to clarify, in general, how the mitigation exemption test and offer floor calculations are implemented."[216]

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208. *Astoria Generating Company L.P. v. New York Indep. Sys. Operator, Inc.*, 139 F.E.R.C. ¶ 61,244 at P 1 (2012) [hereinafter June 22 Order].

209. Astoria Generating Company, L.P., NRG Power Marketing LLC, Arthur Kill Power LLC, Astoria Gas Turbine Power LLC, Dunkirk Power LLC, Huntley Power LLC, Oswego Harbor Power LLC, and TC Ravenswood (collectively, the Complainants). Complaint Requesting Fast Track Processing, *Astoria Generating Co. v. New York Indep. Sys. Operator, Inc.*, FERC Docket No. EL11-42-000 (filed June 3, 2011, amended June 15, 2011) [hereinafter Complaint].

210. June 22 Order, *supra* note 208, at PP 1, 6.

211. *Id.* at P 1.

212. Complaint, *supra* note 209, at 23.

213. *Id.* at 24 (citation omitted).

214. June 22 Order, *supra* note 208, at P 48.

215. *Id.* at P 49 (citation omitted).

216. *Id.* at P 50.

### *C. NYISO's Use of Inflation Adjustments*

The Complainants asserted that the NYISO "may not escalate its Unit Net CONE calculation for new entrants to reflect inflation" and that "[s]uch an approach cannot be squared with the plain language of the Services Tariff, and will result in under-mitigation of new entrants in violation of the intent and design of the Mitigation Exemption Test and the Offer Floors."[217] The Complainants alleged that, if the NYISO were permitted to calculate Unit Net CONE without reflecting inflation costs, then Unit Net CONE would be "set at an artificially low level (*i.e.*, below true costs)," and "a new entrant could improperly escape mitigation altogether, or its bids could be inadequately mitigated."[218]

While the "NYISO's tariff is silent on whether and how inflation should be included in the calculation of Unit net CONE for purposes of the prong (b) Unit exemption test and Unit Offer Floor,"[219] the FERC stated that,

> because the intent is to compare the Unit net CONE amount stated in one year's dollars to demand curve prices stated in dollars of three to six years in the future, it is necessary to restate, i.e., inflate the Unit net CONE value in order to render a valid comparison in constant 'real' dollar terms.[220]

The FERC found that "an inflation factor should be applied to Unit net CONE as part of the exemption analysis to have a valid comparison of Unit net CONE to each year of the Unit Mitigation Study Period projected demand curve prices" so that "an 'apples to apples' comparison of Unit net CONE and projected demand curve prices can be made."[221] As the "Unit net CONE and projected demand curve prices used in applying the prong (b) Unit exemption test should be inflated by the same inflation rate that is included in the latest effective demand curve escalation factor" which currently is an inflation rate of 1.7%,[222] the FERC directed the NYISO to revise its tariff to use that inflation rate.[223]

The FERC also found the Services Tariff "to be silent on the question of whether, once set, the offer floor applicable to a non-exempt unit should be adjusted annually for inflation and/or changes in effective demand curves after the non-exempt unit enters the ICAP market."[224] The FERC concluded that the offer floor for a non-exempt unit should be adjusted annually for inflation, and not monthly as asserted by the Complainants.[225] The FERC explained that "[w]ithout an inflation adjustment, a static offer floor would understate Unit net CONE over time" and that "[t]his could permit a new entrant to be exempt in monthly auctions leading to a suppression of market clearing prices and permit uneconomic entry into a market."[226] The FERC added that "[t]o maintain

217. Complaint, *supra* note 209, at 26.

218. *Id.* at 25-26.

219. June 22 Order, *supra* note 208, at P 60.

220. *Id.*

221. *Id.*

222. *Id.* at P 62 (citing *New York Indep. Sys. Operator, Inc.*, 134 F.E.R.C. ¶ 61,058 at PP 142, 150 (2011)).

223. June 22 Order, *supra* note 208, at P 63.

224. *Id.* at P 72.

225. *Id.*

226. *Id.* at P 73.

consistency within the buyer-side mitigation rules, [the] tariff revisions should state that inflation will be applied annually to offer floors of a non-exempt unit entering the market, at the inflation rate component of the escalation factor determined in the demand curve process."[227]

### *D. NYISO's Proposed Use of an Outdated Demand Curve for Calculation of Future Capacity Prices*

The Complainants alleged that the NYISO proposed "to base its ICAP price projections on an ICAP Demand Curve first established in 2008 . . . without any changes based on actual increased costs of the proxy unit or inflation . . . to project capacity prices for May 2011 through April 2014."[228] Describing the NYISO's approach as "patently unreasonable" in that it "will result in unreasonably low values that, in turn, could allow new entrants improperly to evade mitigation,"[229] they requested that the FERC "direct the NYISO to use the most recently approved Net CONE values."[230]

The FERC agreed with the Complainants that "it would be unreasonable to compare the Default net CONE value associated with demand curves from one year with the projected ICAP prices based on demand curves of a different year in determining whether a supplier should be exempted from mitigation."[231] The FERC noted that "the mitigation exemption test provisions of NYISO's tariff in fact require a comparison between the average of ICAP spot market auction prices projected for the first year after entry and the Default net CONE projected for that same year."[232] The FERC directed the NYISO "to use values from the same demand curve that is effective at the time it makes an exemption determination in comparing Default net CONE with spot market auction prices."[233]

### *E. NYISO's Review of All New Entrants' Contracts*

The Complainants explained that the "NYISO does not intend to review important contracts underlying the Unit Net CONE calculation, including wholesale power and capacity contracts" and that, without reviewing these contracts, it would be impossible for NYISO "to determine whether new entrants are seeking to artificially lower their Unit Net CONEs by using subsidies or other out-of-market revenues, or even whether they can actually support their claimed costs of construction."[234] The Complainants asked the FERC to direct the NYISO "to require new entrants to provide all contracts necessary for the NYISO to verify their respective estimates of Unit Net CONE" as well as "to identify any arrangements providing implicit or explicit subsidies or that would

227. *Id.* at P 76.
228. Complaint, *supra* note 209, at 31.
229. *Id.*
230. *Id.* at 33.
231. June 22 Order, *supra* note 208, at P 85.
232. *Id.* at P 85 (citation omitted) (citing Services Tariff § 23.4.5.7.2).
233. *Id.* at P 85.
234. Complaint, *supra* note 209, at 39.

otherwise give the new entrant an incentive to bid below costs or that would make it indifferent to ICAP clearing prices."[235]

The FERC denied the Complainants request to direct the NYISO to require new entrants to provide all such contracts and to identify any such arrangements.[236] The FERC disagreed with the Complainants that the "NYISO should consider out-of-market revenues to determine if the supplier has an incentive to understate costs."[237] The FERC explained that the "NYISO's task is to verify a new entrant's Unit net CONE based on cost information supplied by the new entrant" and that "[t]he Services Tariff is explicit that a new entrant that wants to rely on its Unit net CONE must provide all required cost information to NYISO."[238] The FERC therefore did not require the NYISO "to extend its review of a new entrant's Unit net CONE determination to consider out-of-market revenues."[239]

### *F. NYISO's Use of Natural Gas Prices in Unit Net CONE*

The Complainants explained that the NYISO previously "rejected using futures gas prices to estimate energy revenues for purposes of calculating [the] Net CONE" value underlying the demand curves and mitigation exemption test determinations, but then proposed to "calculate [energy and ancillary services] revenues for purposes of making its mitigation exemption determinations based on NYMEX futures gas prices."[240] The Complainants asserted that "such inconsistency will impede the proper functioning of the Buyer-Side Market Power Rules."[241]

The FERC denied the Complainants' request to direct the NYISO "to provide detailed information needed to confirm that the use of natural gas futures prices will not skew its Unit net CONE calculations."[242] The FERC found that the NYISO "justified the use of natural gas futures prices in the calculation of the net energy revenue offset used to determine the Unit net CONE" and "[did] not find it necessary to require NYISO to explain this result further or quantify its impact on Unit net CONE."[243] The FERC also disagreed with the Complainants that NYISO should use historical natural gas prices to determine the Unit net CONE value.[244] The FERC explained that "prong (b) [of the mitigation test] compares average expected capacity revenues over the resource's first three years of operation with Unit Net CONE" and that "[i]t is more important in this context to accurately estimate the individual years' net energy and ancillary service revenues."[245] Thus, "natural gas futures prices are likely to provide the more accurate forecast of future natural gas prices in the

235. *Id.* at 40.
236. June 22 Order, *supra* note 208, at PP 89, 93.
237. *Id.* at P 93.
238. *Id.* (citing Services Tariff § 23.4.5.7.3.6).
239. *Id.*
240. Complaint, *supra* note 209, at 43.
241. *Id.*
242. June 22 Order, *supra* note 208, at PP 97, 105.
243. *Id.* at P 105.
244. *Id.* at PP 108-09.
245. *Id.* at P 109.

near term individual years than would historical natural gas prices" because "a natural gas futures price at any point in time is the price at which market participants are willing to transact at that time for delivery of gas at a specified time in the future."[246]

## VI. EUROPEAN ISSUES

### *A. E.ON Ruhrgas-Appeal of Antitrust Fine*

On June 29, 2012, the European General Court reversed in part a 2009 decision of the European Commission (EC) imposing fines of € 553 million on both E.ON Ruhrgas AG of Germany (E.ON) and GDF Suez SA of France (GDF) for horizontal allocations of gas markets based on the existence of an agreement to preclude competition in Germany from 1980 to 2005 and in France from 2000 to 2005.[247] The Court ruled that the agreement not to compete in Germany was lawful prior to 1998 because the German utility had a *de facto* monopoly that was permissible under German law during that time;[248] and that, as to the French market, the EC failed to cite evidence that the agreement not to compete continued after August 2004.[249] However, the Court sustained the EC's ruling that the market allocations were not legal as ancillary restrictions necessary to give effect to a lawful joint venture.[250]

The market allocations arose out of a joint venture in 1975 between Ruhrgas (subsequently acquired by E.ON) and GDF (which later merged with Suez) to build a pipeline to import Russian gas into Germany and France.[251] As part of the joint venture, the parties entered into side letters on a number of issues, including two which embodied commitments of each not to market gas in the service territory of the other.[252] The pipeline, known as MEGAL, started operating in 1980.[253]

Under a law dating from 1957, German utilities could obtain government permission to operate exclusive territories and to divide markets.[254] Germany repealed that law in 1998,[255] the same year that the European Union (EU) initiated deregulation of natural gas transportation.[256] In France, a 1946 law nationalized the gas distribution business and gave GDF, the nationalized company, a monopoly on gas imports and exports. France repealed the monopoly and opened its gas market to competition in 2003.[257]

246. *Id.*

247. Case T-360/09, E.ON Ruhrgas AG v. Comm'n, http://curia.europa.eu/juris/documents.jsf?num=T-360/09 (June 29, 2012).

248. *Id.* ¶¶ 94-106, 112-16, 155.

249. *Id.* ¶¶ 241-46.

250. *Id.* ¶¶ 62-81.

251. *Id.* ¶ 17.

252. *E.ON Ruhrgas AG*, *supra* note 247, ¶¶ 21-23.

253. *Id.* ¶ 17.

254. *Id.* ¶ 6.

255. *Id.* ¶ 7.

256. *Id.* ¶ 1.

257. *E.ON Ruhrgas AG*, *supra* note 247, ¶¶ 10-12.

Under European competition law, horizontal market allocations are only illegal in markets that are open to actual or potential competition.[258] In its Order imposing the fines, the EC determined that Ruhrgas could have faced competition between 1980 and 1998, because the German government retained the authority in that era to reject utility applications for exclusive territories and agreements not to compete, and had on occasion allowed third parties access to the market.[259] With respect to the French market, the EC determined that while France did not legally abolish the monopoly of GDF until 2003, there was the potential for competition beginning in 2000, the year in which France was required to implement the EU's directive to deregulate natural gas markets.[260] In both the German and French markets, the EC found that the violations in practice continued until 2005, even though the parties had officially annulled the side letters in 2004.[261]

In reversing the EC's decision to impose a fine for the period of 1980 to 1998 in Germany, the Court rejected the EC's reasoning that the German market was open to competition during that period. The Court held that Ruhrgas had a *de facto* monopoly in view of the ease with which it could get permission from the government to exclude competition within its service territory.[262] The EC distinguished instances in which third parties had gained access to the market as atypical and unlikely to be repeated.[263]

In reversing the EC's decision to impose a fine for the period of 2004 to 2005 in France, the Court noted that the EC failed to provide any direct evidence of agreement not to compete during that period, but had instead only inferred such an agreement.[264]

The utilities had unsuccessfully argued before the EC that the commitments not to compete in the side letters should be considered lawful as ancillary restrictions necessary to a lawful joint venture.[265] On appeal, the Court upheld the EC's rejection of this argument.[266] It noted, first, that under European law, ancillary restrictions are not judged under a "rule of reason."[267] The only relevant legal issues were whether they were in fact necessary for the joint venture to proceed and, if so, whether their scope and duration did not exceed what was necessary.[268] Based on evidence that Ruhrgas would have constructed the pipeline by itself if GDF had been unable to participate, the Court found no error in the EC's reasoning on this issue.[269]

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258. *Id.* ¶¶ 84-85.
259. *Id.* ¶¶ 94, 111-13.
260. *Id.* ¶¶ 89-92.
261. *Id.* ¶ 39.
262. *E.ON Ruhrgas AG*, *supra* note 247, ¶¶ 94-116.
263. *Id.* ¶ 112.
264. *Id.* ¶¶ 241-46.
265. *Id.* ¶ 71.
266. *Id.* ¶ 81.
267. *E.ON Ruhrgas AG*, *supra* note 247, ¶ 65.
268. *Id.* ¶¶ 67-68.
269. *Id.* ¶¶ 73-81.

### *B. Gazprom- Investigation of Anticompetitive Practices in Upstream Gas Markets*

On September 4, 2012, the EC began investigating "whether Gazprom, the Russian producer and supplier of natural gas, . . . [is] abusing its dominant market position in upstream gas supply markets in Central and Eastern European Member States in violation of Article 102 of the 2010 Treaty on the Function of the European Union."[270] At issue is whether Gazprom: (1) has been dividing markets by "hindering the free flow of gas across Member States"; (2) may have prevented the diversification of gas supply; and (3) "imposed unfair prices . . . by linking the price of gas to oil."[271]

### *C. Approval of Dong Energy-Boston Holding Offshore Windpark Joint Venture*

On May 10, 2012, the EC approved the formation of a joint venture between Dong Energy and Boston Holding to own Borkum Riffgrund I, an offshore windpark development company.[272] While Dong Energy was involved in Northern European generation and energy markets, Boston Holding was formed by entities with no prior energy market involvement.[273] The EC concluded that the venture did not raise competitive concerns.[274] But the EC reaffirmed its market definition, enforcing that: (1) the development of wind farms in order to sell energy into the wholesale market, and the development of those farms in order to sell them to third parties, are not separate product markets;[275] and (2) geographic markets for wind farm development are essentially national in scope, in view of differences in regulatory frameworks between member states, "the need to have a good network of local business contacts [and the] different administrative steps that need to be taken in the course of the wind-farm development."[276]

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270. Press Release, Eur. Comm'n, Antitrust: Commission Opens Proceedings Against Gazprom (Sept. 4, 2012), *available at* http://europa.eu/rapid/press-release_IP-12-937_en.htm.

271. *Id.*

272. *Dong Energy Borkum Riffgrund I Holdco/Boston Holding Borkum Riffgrund I Offshore Windpark*, Eur. Comm'n Case No. Comp/M.6540, ¶ 47 (May 10, 2012), *available at* http://ec.europa.eu/competition/mergers/cases/decisions/m6540_20120510_20310_2569287_EN.pdf.

273. *Id.* ¶¶ 1-4.

274. *Id.* ¶ 46.

275. *Id.* ¶ 22.

276. *Id.* ¶ 27.

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